A Life Cycle Comparison of Coal and Natural Gas for Electricity Generation and the Production of Transportation Fuels

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When I graduated with my bachelor's degree four and a half years ago, I had already decided that I wanted to go to graduate school in order to get a master's degree, but I was sure I was not interested in pursuing a PhD. I did not think I wanted to commit to years of research and I also did not think I wanted to be a professor (which was the only reason I could think of for being a Doctor of Philosophy). Thankfully, I decided to come and get my master's degree at Carnegie Mellon, where I found a group of people doing great research in a great collegial environment and I was convinced that I had to stay here to get a PhD. Throughout this four and a half years there are many people that have supported me in one way or another and have helped me navigate the good and the not so good of being a graduate student.

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ABSTRACT

Demand for electricity is expected to increase in the next 25 years. Currently, 50% of the electricity generated in the U.S. is produced using coal. Although natural gas has traditionally been used by the commercial, industrial and residential sector, demand for natural gas for electricity generation has increased in the past decade and this growth is expected to continue in the next 25 years. Since demand is growing but North American supply is expected to remain constant, alternative sources of natural gas will need to be developed. LNG has been identified as one alternative, and plans to increase imports of this fuel are underway. In addition, synthetic natural gas.

The demand for natural gas by the transportation sector is currently negligible, but worldwide interest on natural gas-derived transportation fuels (such as natural gas based Fischer-Tropsh Liquids and Compressed Natural Gas) is increasing. The U.S. could either produce these fuels internally, requiring larger imports of LNG, or import them from natural gas-rich countries. Alternatively, the U.S. could produce transportation fuels from coal. Although non-existent in 2005, by 2030 coal-to-liquid-fuel producers are expected to consume as much coal as coke plants. Thus, the production of transportation fuels is an additional end-use where coal and natural gas could compete as the fuel of choice.

The goal of this research is to compare coal and natural gas for use by the electric power sector and for the production of transportation fuels in the next 25 years. This comparison concentrates on the life cycle GHG emissions of these fuels. In addition to comparing natural gas and coal to determine which fuel is better suited for each end-use, a comparison of each end-use will also be performed in order to help determine which is a better use of each fuel.

Two main results arise from this research. First, it was found that in a future where advanced power plant technologies with carbon capture and sequestration are used, coal

and globally sourced natural gas could have very similar life cycle GHG emissions. This begs the question of whether investing billions of dollars in LNG/SNG infrastructure will lock us into an undesirable energy path that could make future energy decisions costlier than ever expected and increase the environmental burden from our energy infrastructure.

Second, it was found that the use of transportation fuels derived from coal and natural gas will not help the U.S. reduce the GHG emissions associated with the life cycle of transportation fuels, and in a worse case scenario, the use of these alternative fuels could in fact increase these GHG emissions. In addition, it was found that there is high uncertainty associated with the energy security benefits that could be associated with the consumption of transportation fuels derived from coal.

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LIST OF ACRONYMS

BOG: Boil-Off Gas CCS: Carbon Capture and Sequestration CTL: Coal-to-Liquids DOE: Department of Energy EIA: Energy Information Administration EPA: Environmental Protection Agency FERC: Federal Energy Regulatory Commission FT: Fischer-Tropsch GREET Model: Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model GTL: Gas-to-Liquids IGCC: Integrated Gasification Combined Cycle kWh: Kilo-Watt hour LNG: Liquefied Natural Gas LNGCC: Liquefied Natural Gas Combined Cycle MCF: Million Cubic Feet MMBtu: Million British Thermal Units MW: Mega-Watt MWh: Mega-Watt hour NG: Natural Gas NGCC: Natural Gas Combined Cycle PC: Pulverized Coal SNG: Synthetic Natural Gas tcf: Trillion Cubic Feet

1 INTRODUCTION AND BACKGROUND INFORMATION

Energy use is everywhere: we turn on the lights in our homes, turn on the furnace in winter and the air conditioner in summer, drive our cars, and without energy we would have no cans to hold our food, no cement or steel for our buildings, or even the flowers on our table. There are major challenges in our current energy systems. Among these, is the issue of climate change. Electricity generation and the consumption of transportation fuels are the largest sources of the greenhouse gas emissions that contribute to climate change. Traditionally, fossil fuels like coal and petroleum have been used in these systems.

The Department of Energy (DOE) estimates that in the coming decades U.S. natural gas demand for electricity generation will increase, even as coal remains the primary fuel used by electric utilities. Estimates also suggest that natural gas supply will increasingly come from imported liquefied natural gas (LNG) (1). Additional supplies of natural gas could come domestically from the production of synthetic natural gas (SNG) via coal gasification-methanation (2).

Just as we are looking for additional sources of natural gas to satisfy the increased demand by electricity generators, we are also searching for alternative transportation fuels that could help us relieve the pressure on oil imports. Hydrogen is often mentioned as the panacea of transportation fuels. We are, however, decades away from the hydrogen economy that some envision. Nearer to commercial realization are transportation fuels derived from coal or natural gas.

Any increased consumption of coal or natural gas will have implications for greenhouse gases (GHG) emissions. Similarly if we want to increase consumption of coal and natural gas, either to generate electricity or to produce transportation fuels, we will have to think about the implications this will have for the availability of resources and in the costs of different fuels and energy sources. It is important to try to figure out what these impacts

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will be in order to better determine which fuel is better suited for a specific use, and also which is a better use of the resources available.

Fossil fuels are the largest energy source in the United States. Petroleum, coal and natural gas account for about 40%, 23% and 24% of the total energy consumed in the U.S., respectively (1). Petroleum is used primarily by the transportation sector (1). Coal is used primarily for electricity generation, producing approximately 50% of generated electricity (1). Approximately 70% of natural gas is used in equal parts by chemical industries and by commercial/residential consumers, while the remaining natural gas is used to produce 18% of U.S. electricity (1).

Recently, concern about greenhouse gas (GHG) emissions has increased. Power generation has been of great concern, as it is the largest GHG emitting sector in the U.S. economy (3). In the early 1990's, the wellhead price of natural gas was low and as a result, there was a surge in construction of natural gas-fired power plants: between 1992 and 2003, while coal-fired capacity increased only from 309 to 313 GW, natural gas-fired capacity more than tripled, from 60 to 208 GW (4). The decision to build these natural gas fired-plants was economically motivated, but is also made sense in the context of reducing GHG emissions, as natural gas has lower combustion emissions than coal (5). The construction and operation of these plants, however, resulted in high natural gas prices but only a minimal gain in emission control (most of these plants are currently operating at low use rates (2)). Today, in order to increase supply and lower fuel cost, there is a growing desire to import natural gas via liquefied natural gas (LNG). By 2030, more than 15% of the U.S. natural gas supply is expected to come in the form of LNG (1). Alternatively, Rosenberg et al. (2) call for congress to promote gasification technologies that use coal to produce synthetic natural gas (SNG). The National Gasification Strategy would allow the U.S. to produce 1.5 trillion cubic feet (tcf) of SNG per year within the next 10 years; equivalent to 5% of expected 2030 supply (1). This would not eliminate the need to import LNG, but it would decrease the amount of LNG required.

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Economics dictate that one solution for the problem of high natural gas prices and underutilization of natural gas-fired capacity is to increase our LNG/SNG consumption. However, this strategy ignores important environmental and technical considerations. Although natural gas combustion air emissions are lower than other fuels, no examination of life cycle emission impacts of increased LNG/SNG consumption for electricity generation, or comparison to the life cycle emissions of other fuels has been done. Without this comparison it is not possible to determine if natural gas really is a better choice for electricity generation.

Environmental life cycle assessment (LCA) is defined as an analysis of the environmental impacts associated with the "cradle-to-grave" cycle of a product. This includes the impacts associated with all the processes through which a product goes, beginning with the extraction of raw materials for production and ending with the disposal of the product. By including all the life cycle stages of the product, impacts that are not included in more traditional, use-phases analysis can be estimated, allowing us to determine cumulative environmental impacts for each product.

While the electric power sector is the largest GHG emitter in the U.S., the second largest source of emissions is the transportation sector (1). The transportation sector is also the largest consumer of petroleum fuels (1). More than 60% of the petroleum consumed in the U.S. is imported from other countries (1), creating concerns for the energy security of the country. The search for sustainable alternative fuels has begun. Two possibilities are liquid fuels produced from coal and natural gas. For example, in 2005 production of liquid fuels from coal in the U.S. was non-existent. By 2011, EIA predicts that, production of these fuels will slowly start increasing so that by 2030 coal-to-liquid-fuel producers will consume about as much coal as coke plants (expected demand by each of these sector is expected to be around 60 million tons of coal, which is still not a very significant amount of coal consumed compared to the demand by electricity generators, 1,570 million tons) (1). EIA forecasts have been known for being overly optimistic in some cases as they ignore things like possible future policy changes, such as GHG controls. These forecasts, however, are the best publicly available forecasts and are used

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throughout this thesis to give context to the numbers that were developed. It should be noted that the use of these forecasts does not change the overall result of the analysis presented here.

Again, a life cycle comparison of the emissions associated with these transportation fuels should be performed. These comparisons can help policy makers define which fuel is best suited for each use, and also which is a better use of each fuel.

This thesis addresses three main research questions: Is it better to use coal or natural gas for electricity generation? Is it better to use coal or natural gas for the production of transportation fuels? And, which is a better use of each fuel, electricity generation or the production of transportation fuels? To answer these questions, this research has been divided into four stages. In the first stage, the life cycle of coal and natural gas are defined and a greenhouse gas (GHG) emission inventory is performed, as presented in Chapters 2. For the second stage, presented in Chapter 3, the emissions previously developed are used to determine life cycle GHG emissions of electricity generated with coal and with globally sources natural gas. Electricity generated in currently operating power plants, as well as electricity generated in advanced power plants with carbon emissions are separated from other combustion products and injected into underground geologic formations such as deep saline formations and depleted oil/gas fields.

Similar in approach to the second stage, the third stage (Chapters 4) consists of a comparison of life cycle GHG emissions of transportation fuels (Fischer-Tropsch (FT) liquid fuels, and compressed natural gas) derived from coal and natural gas. In this stage, an economic analysis of the FT-liquid fuels is performed. Finally, in the fourth stage of this thesis, I perform a brief analysis comparing electricity generation and transportation fuel production. This comparison, concentrates only in emissions of GHG, as seen in Chapter 5.

The result of each of these research stages makes relevant contributions in the context of energy policies in the U.S. By determining whether it is better to use coal or natural gas/LNG/SNG for electricity generation (stage 2), a fundamental question regarding the future consumption of fossil fuels by the U.S. electric industry is answered. The U.S. is currently on a path of increased natural gas consumption (led by increased consumption for electricity generation) that has lead us to the search for alternative sources of natural gas. But what if the use of coal for electricity generation has lower environmental impacts? If we follow the current path without answering this fundamental question, we may find ourselves locked into an undesirable path that might make our future energy choices costlier.

As previously described, transportation fuels derived from coal or natural gas are being considered to replace some of our demand for petroleum-based fuels. Once again, the comparison between transportation fuels derived from coal, and transportation fuels derived from natural gas (stage 2) could help policy makers identify which is an environmentally friendlier and cheaper source for such fuels.

Finally, in the fourth stage, I start to consider the idea of comparing the different uses in order to identify which is a better use of each fuel. As mentioned before, it could be found that coal is better suited to produce transportation fuels than natural gas, but what if this is not the best use of our coal resources? Would it then make sense to use natural gas to produce these transportation fuels?

2 THE LIFE CYCLE OF COAL AND GLOBALLY SOURCED NATURAL GAS AND THE EMISSIONS ASSOCIATED WITH THESE LIFE CYCLES¹

As previously described, environmental life cycle assessment (LCA) is defined as an analysis of the environmental impacts associated with the "cradle-to-grave" cycle of a product. For coal and natural gas, this includes the impacts associated with all the processes through which the fuels go through, beginning with the extraction and ending with the use. By including all the life cycle stages of the product, impacts that are not included in more traditional, use-phases analysis can be estimated, allowing us to determine cumulative environmental impacts for each product. The following sections describe the life cycle of coal, and globally sourced natural gas, as well as the emissions associated with these life cycles. A description of the life cycle of synthetic natural gas (SNG) is also included.

Rosenberg et al. (2) developed a program in which they call for Congress to promote gasification technologies that use coal, biomass, or petroleum coke to produce synthetic natural gas (SNG). The National Gasification Strategy would allow the U.S. to produce 1.5 trillion cubic feet of synthetic natural gas per year, the equivalent of what could be expected to be transported by the Alaska Gas Pipeline (2). This additional domestic supply of natural gas would reduce the need for imports of LNG.

¹ Much of the text from this chapter is based on the following published paper: Jaramillo;, P.; Griffin;, W. M.; Matthews, H. S., "Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation." Environmental Science and Technology 2007, 41, 6290-6296.

2.1 The Life Cycle of Coal, Globally Sourced Natural Gas, and SNG

This section presents a qualitative description of the life cycle of coal and globally sourced natural gas. An understanding of these life cycles was imperative before I could start performing an inventory of the emissions associated with each fuel.

2.1.1 The Life Cycle of Globally Sourced Natural Gas

The natural gas life cycle starts with the production of natural gas and ends at the combustion plant. Natural gas is extracted from wells and sent to processing plants where water, carbon dioxide, sulfur and high molecular weight hydrocarbons are removed. The natural gas then enters the transmission system. In the U.S., this transmission system is the interstate natural gas pipeline network, which consists of thousands of miles of highpressure pipelines that transport the gas from producing areas to high demand areas. Compressor stations that use a turbine or an engine maintain the pressure in these pipes. Historically, the turbines and engines generally ran with a small amount of the gas from the pipeline. With the rising price of gas, growing numbers of pipelines now use electricity to run their turbines and engines. Natural gas can be stored to meet seasonal demand increases or to meet sudden, short-term demand increases. Natural gas is usually stored in underground facilities, such as reconditioned depleted gas reservoirs, aquifers, or salt caverns. Distribution is the final step before consumers use natural gas. Local distribution companies transport natural gas from delivery points along the transmission system to local consumers via low-pressure, small-diameter pipelines. Small compressors are used in the distribution system to maintain the pressure required.

When liquefied natural gas (LNG) is added to the natural gas mix, three additional life cycle stages are created: liquefaction, tanker transport, and regasification. Figure 1 illustrates the total life cycle of natural gas including the LNG stages.



Figure 1: Natural Gas Life Cycle Including LNG.

In the liquefaction process, natural gas is cooled and pressurized to convert it to liquid form, reducing its volume by a factor of 610 (6). These liquefaction plants are generally located in coastal areas of LNG exporting countries. In 2003, 75% of the LNG imported to the U.S. came from Trinidad and Tobago, but this percentage is expected to decrease as more imports come from Russia, the Middle East, and Southeast Asia (7). Dedicated LNG tankers bring this gas to the U.S. According to EIA, there were 151 LNG tankers in operation worldwide as of October 2003. The majority of these tankers have the capacity to carry more than 120,000 cubic meters of liquefied natural gas (equivalent to 2.59 billion cubic feet of natural gas), which is enough gas to supply an average of 31,500 residences for a year (7). Total fleet capacity was expected to have reached 25.1 million cubic meters of liquid (equivalent to 527 billion cubic feet of natural gas) by the end of 2006 (8).

Regasification facilities are the last step LNG must pass through before going into the U.S. pipeline system. Regasification facilities are LNG marine terminals where LNG tankers unload their gas. These facilities consist of storage tanks and vaporization equipment that warms the LNG to return it to the gaseous state. There are currently 5 LNG terminals in operation in the U.S.: Lake Charles, Louisiana; Elba Island, Georgia; Cove Point, Maryland; Everett, Massachusetts; and a recently opened offshore terminal in the Gulf of Mexico. These terminals have a combined base load capacity of 5.3 billion cubic feet per day (about 2 trillion cubic feet per year). In addition to these terminals, there are 45 proposed facilities in North America, 18 of which have already been approved (9). Not all these facilities will be built, as approval from FERC is only a first step toward constructing a terminal. This number, however, shows that there is great interest in the U.S. to start developing the LNG infrastructure.

2.1.2 The Coal Life Cycle

The coal life cycle is conceptually simpler than the natural gas life cycle, consisting of the three steps shown in Figure 2.



Figure 2: Coal Life Cycle.

In the U.S., 67% of the coal is extracted from surface mines, while the remaining 33% is extracted from underground mines (3). Mined coal is then processed to remove impurities. Coal is transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (10). More than 90% of the coal used in the U.S. is used by the electric power sector (11).

2.1.3 The Life Cycle of Synthetic Natural Gas

The life cycle of SNG produced from coal is composed of some stages from the coal life cycle and some stages of the natural gas life cycle, as shown in Figure 3. Coal is mined, processed, and transported to the gasification plant. At this plant, syngas, a mixture of carbon monoxide (CO) and hydrogen (H), is produced. This syngas is then used in a methanation reactor, where CO and H are converted into methane and water. The SNG is then sent to the natural gas transmission, storage and distribution system that delivers it to natural gas consumers.



Figure 3: SNG Life Cycle.

2.2 Calculating the Upstream Emissions of Coal and Globally Sourced Natural gas

In this study, I investigate the life cycle air emissions from coal, and globally sourced natural gas (including North American natural gas, LNG and SNG). The comparison focuses on the use of these fuels for electricity generation and the production of transportation fuels. The emissions from the plants where the electricity and the transportation fuels are produced will be described in following chapters. This section only deals with the method used to calculate the emissions from the upstream of use stages of the fuels, from well/mine to plant.

2.2.1 Upstream Emissions from Natural Gas Produced in North America

During the late 1980s and early 1990s the U.S. Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry (12). This comprehensive study developed hundreds of activity and emissions factors from all areas of the natural gas industry. These factors were developed using data collected from different sectors of the industry as well as from data collected in field measurements. Methane emissions from the U.S. natural gas system given as a percentage of natural gas produced can be seen in Table 1.

In 2003, the total consumption of natural gas in the U.S. was over 27 trillion cubic feet (tcf). Of this, 26.5 tcf were produced in North America (U.S., Canada, and Mexico) (7). This production data was used to develop methane emission factors using the percentage of natural gas lost. It was also assumed that natural gas has an average heat content of 1,030 Btu/ft³ (7), and that 96% of the natural gas lost is methane, which has a density of 0.0424 lbs/ ft³ (12).

Life Cycle Segment	Emissions as a Percentage of Gas Produced
Production	0.38%
Processing	0.16%
Transmission and Storage	0.53%
Distribution	0.35%

Table 1: Methane Emissions from North American Gas Life cycle as a Percentage of Natural Gas Produced (12).

In 1993 the U.S. EPA established the Natural Gas STAR program to reduce methane emissions from the natural gas industry. The program is a voluntary partnership with the goal of encouraging the natural gas industry to adopt practices that increase efficiency and reduce emissions (for example by reducing natural gas leaks in the pipeline system). Consequently, since 1993, a cumulative total of 338 billion cubic feet of methane emissions have been eliminated. In 2003 alone, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (13). These methane emission reductions were combined with the data described above in order to develop a range of methane emissions factors for the North American natural gas life cycle stages.

Note that Table 1 includes an estimate for natural gas losses in the local distribution system. For this research, natural gas used by electricity generators and liquid fuel producers is assumed to be delivered directly through the transmission system, so it does not pass through local distribution companies. Methane lost in this stage is given here for reference, but it was not included in my calculations.

Carbon dioxide emissions are produced from the combustion of natural gas used during various life cycle stages and from the production of electricity consumed during transport. The Energy Information Administration (EIA) provides annual estimates of the amount of natural gas used for the production, processing, and transport of natural gas, as shown in Table 2. Total carbon dioxide emissions were calculated using a carbon content

in natural gas of 31.9 lbs C/MMBtu and an oxidation fraction of 0.995 (3). In addition, according to the Transportation Energy Data Book, 3 billion kWh were used by natural gas pipeline transport in 2003 (14). The average GHG emission factor from the generation of this electricity is 1,400 lbs CO2 Equiv/MWh (15). These CO₂ emissions were added to methane emissions to obtain the upstream GHG emission factors for North American natural gas.

Use (as defined by EIA)	NG Life Cycle Stage	Amount (million ft ³)
Flared Gas	Production	98,000
Lease Fuel	Production	760,000
Pipeline Use	Transmission/Distribution	665,000
Plant Fuel	Processing	365,000

Table 2: Natural Gas Used During the Natural Gas Life Cycle in 2003 (7).

The data shown in Table 2 were also used to calculate SO_x and NO_x emissions from the life cycle. Total emissions from flared gas were calculated using the AP 42 Emission Factors for natural gas boilers (16). A range of emissions from the combustion of the natural gas used during the upstream stages of the life cycle was developed using the AP 42 Emissions Factors for reciprocating engines and for natural gas turbines (16). Emissions from generating the electricity used during natural gas pipeline operations were estimated using the most current average emission factors given by EGRID: 6.04 lbs SO_2/MWh and 2.96 lbs NO_x/MWh (15). Note that EGRID reports emissions of SO_2 only. Other references used in this paper report total SO_x emission. For this thesis, sulfur emission will be reported in terms of SO_x emissions.

It should be mentioned that the pipeline fuel presented in Table 2 includes fuel used by the transmission system and the local distribution system. As previously described, natural gas used by electricity generators is bought directly from the transmission system, so that emissions from the distribution system are not included in this analysis. The same assumption is used for liquid-fuel-producers, which could become large consumers of natural gas. Due to data limitations, I was not able to disaggregate pipeline fuel and electricity consumption between the two systems. To deal with this issue, I use a range of emissions. The minimum value assumes that none of this pipeline fuel is consumed in the transmission system and the maximum value assumes that all is consumed in the transmission system.

In addition to emissions from the energy used during the life cycle of natural gas, SO_x emissions are produced in the processing stage of the life cycle, when hydrogen sulfide (H₂S) is removed from the sour natural gas in order to meet pipeline requirements. A range of SO_x emissions from this processing of natural gas was developed using the AP 42 emissions factors for natural gas processing and for sulfur recovery (16). In order to use the AP 42 emission factors for sulfur recovery, it was found that in 2003 1,945 thousand tons of sulfur were recovered from 14.7 trillion cubic feet of natural gas resulting in a calculated average natural gas H₂S mole percentage of 0.0226. This was then used with the AP 42 emission factors for natural gas processing.

2.2.2 Upstream Emissions from Imported LNG

In 2003, 500 billion cubic feet of natural gas were imported in the form of LNG (7). In 2003, 75% of the LNG imported to the U.S. came from Trinidad and Tobago, but this percentage is expected to decrease as more imports come from Russia, the Middle East, and Southeast Asia (7). According to EIA, the LNG tanker world fleet capacity should have reached 890 million cubic feet of liquid (equivalent to 527 billion cubic feet of natural gas) by the end of 2006 (8). There are currently 5 LNG terminals in operation in the U.S., with a combined base load capacity of 5.3 billion cubic feet per day (about 2 trillion cubic feet per year). In addition to these terminals, there are 45 proposed facilities in North America, 18 of which have already been approved by the Federal Energy Regulatory Commission (FERC) (9).

Due to unavailability of data for emissions from natural gas production in other countries, it is assumed that natural gas imported to the U.S. in the form of LNG produces the same emissions from the production and processing life cycle stages as North American natural gas. Those stages are incorporated for LNG. Most of the natural gas converted to LNG is produced from modern fields developed and operated by multinational oil and gas companies and so it is assumed to be operated in a similar way to those in the U.S.

It is expected that transportation of natural gas from the production field to the liquefaction plant would have similar emissions as pipeline transport of domestic natural gas. But the emission factor for the U.S. system (which is included in the LNG life cycle) is based on total pipeline distances of over 200,000 miles (17). Since LNG facilities are closely pared with gas fields it is expected that the average distance and the range of distances from production field to an LNG facility would be much smaller than 200,000 miles. Also since there was no reliable data for the myriad of fields and facilities and because suspected impact on the overall life cycle would be minimal, this transport from the fields to the liquefaction terminals was ignored. This would slightly underestimate the emissions from the LNG life cycle.

Additional emission factors were developed for the liquefaction, transport, and regasification life cycle stages of LNG. Tamura et al have reported emission factors for the liquefaction stage in the range of 11 to 31 lbs CO₂ equivalents per million Btu (MMBtu) (18). The sources of these emissions are outlined in Table 3.

Liquefaction	Emission Factors (lb CO ₂ Equivalent/MMBtu)			
	Minimum	Average	Maximum	
CO ₂ from fuel combustion	11	12	13	
CO ₂ from flare combustion	0.00	0.77	1.5	
CH ₄ from vent	0.09	1.3	9.8	
CO ₂ in raw gas	0.09	4.0	6.6	

Table 3: Liquefaction Emission Factors (Adapted from Tamura et al (18)).

LNG is shipped to the U.S. via LNG tankers. LNG tankers are the last ship type to use steam turbine technology in their engines. This technology allows for easy use of boil-off gas (BOG) in a gas boiler. Boil-off rates in LNG tankers range between 0.15% and 0.25% per day when loaded (19,20). When there is not enough BOG available, a fuel oil boiler is used to produce the steam. In addition to this benefit, steam turbines require less maintenance than diesel engines, which is beneficial to these tankers that have to be readily available to leave a terminal in a case of emergency (19).

Most LNG tankers currently in operation have a capacity to carry between 4.2 and 5.3 million cubic feet of LNG (2.6 and 3.2 billion cubic feet of gas). There are smaller tankers available, but they are not widely used for transoceanic transport. There is also discussion about building larger tankers (8.8 million cubic feet), however none of the current U.S. terminal can handle tankers of this size (8).

The rated power of the LNG tankers ranges between 20 and 30 MW, and they operate under this capacity around 75% of the time during a trip (21,22). The energy required to power this engine is 11.6 MMBtu/MWh (23). As previously mentioned, some of this energy is provided by BOG and the rest is provided by fuel oil. A loaded tanker with a rated power of 20 MW, and 0.12% daily boil-off rate would consume 3.88 million cubic feet of gas per day and 4.4 tons of fuel oil per day. The same tanker would consume 115 tons of fuel oil per day on they way back to the exporting country operating under ballast conditions. A loaded tanker with a rated power of 30 MW, and a 0.25% daily boil off rate would get all its energy from the BOG, with some excess gas being combusted to reduce risks of explosion (19). Under ballast conditions, the same tanker would consume 172 tons of fuel oil per day.

For LNG imported in 2003, the average travel distance to the Everett, MA LNG terminal was 2,700 nautical miles (7,24). Table 4 provides the distance from LNG exporting countries to two U.S. LNG terminals and the amount of LNG brought from each country

in 2003. These two terminals were chosen because they are two of the largest terminals in the United States and they represent longest and shortest tanker travel distances for which route information is available. In addition, the range of distances provided is also representative of distances LNG would have to travel if a LNG terminal was located in the U.S. West Coast.

Exporting Country	Distance to Lake Charles Facility (nautical miles) (24)	Distance to Everett, MA Facility (nautical miles) (24)	2003 US Imports (million cubic feet NG) (7)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

Table 4: LNG Exporting Countries in 2003.

To estimate the number of days LNG would travel (at a tanker speed of 20 knots (19)), these distances were used. This trip length can then be multiplied by the fuel consumption of the tanker to estimate total trip fuel consumption and emissions, and these can then be divided by the average tanker capacity to obtain an emission factor. Figure 4 shows the emission factors for LNG tanker transport from each country to each of these terminals. Emissions from tanker transport range between 2 and 17 pounds of CO₂ Equivalent per MMBtu of natural gas.



Figure 4: Tanker Emission Factors for LNG Transport from Each Country. The error bars in this figure only represent variability in the LNG tanker operation characteristics.

Regasification emissions were reported by Tamura et al to be $0.85 \text{ lb } \text{CO}_2$ equiv/MMBtu (18). Ruether et al report an emission factor of 3.75 lb CO_2 equiv/MMBtu for this stage of the LNG life cycle by assuming that 3% of the gas is used to run the regasification equipment (25). The emission reported by Tamura et al differs because they assume only 0.15% of the gas is used to run the regasification terminal, while electricity, which may be generated with cleaner energy sources, provides the additional energy requirements. These values were used as lower and upper bounds of the range of emissions from regasification of LNG.

As with the case for carbon emissions, natural gas produced in other countries and imported to the U.S. in the form of LNG is assumed to have the same SO_x and NO_x emissions in the production, processing, and transmission stages of the life cycle as for natural gas produced in North America. Emission ranges for the liquefaction and regasification of natural gas were calculated using the AP 42 emission factors for reciprocating engines and natural gas turbines (16). It is assumed that 8.8% of natural gas is used in the liquefaction plant (18) and 3% is used in the regasification plants (25). Emissions of SO_x , and NO_x from transporting the LNG via tanker were calculated using the AP 42 emission factor for natural gas boilers and diesel boilers, as well as the tanker fuel consumption previously described.

2.2.3 Upstream Emissions from Coal

Greenhouse gas emissions from the mining life cycle stage were developed from methane releases from mines and from combustion of fuels used at mines. EPA estimates that methane emissions from coal mines in 1997 were 75 million tons of CO_2 equivalents, of which 63 million tons of CO_2 equivalents came from underground mines and 12 million tons of CO_2 equivalents came from surface mines (3). CO_2 is also emitted from mines through the combustion of the fuels that provide the energy for operation. The U.S Census Bureau provides fuel consumption data for mines in 1997 (26). These data can be seen in Table 5. Fuel consumption data were converted to GHG emissions using the carbon content and heat content of each fuel and an oxidation fraction given in EPA's Inventory of U.S. Greenhouse Gas Emissions Sources and Sinks (3) and shown in Table 6, below. Emissions from the generation of the electricity consumed were calculated using an average 1997 emission factor of 1400 lbs CO_2 equiv./MWh (15). These total emissions were then converted to an emission factor using the amount of coal produced in 1997 and the heat content of this coal (Table 7)

Mine Type Fuel Oil (1,000 bbl)		Gas	Gasoline	Electricity		
while Type	Total	Distillate	Residual	(10^{9} ft^{3})	(10^6 gal)	(10^6 KWh)
Surface	8,280	7,524	756	0.7	30	42,474
Underground	801	656	145	0.5	4	7,123

Table 5: 1997 Fuel Consumption at Coal Mines (26)

Fuel Type	Carbon Content of Fuel lb/MMBtu Fuel	Heat Content of Fuel (MMBtu/bbl - MMBtu/MMcf)	Fraction Oxidized
Distillate	43.98	5.825	0.99
Residual	47.38	6.287	0.99
Gas	31.90	1,030	0.995
Gasoline	42.66	5.253	0.99

 Table 6: Carbon Content, and Heat Content of Different Fuels (3).

 Table 7: 1997 Coal Production Data (27).

Mine Type Coal Produced (1,000 tons)		Heat Content of Coal (Btu/lb)
Surface	669,273	9,626
Underground	420,657	11,944
Total	1,089,930	10,520

Emissions from the transportation of coal were calculated using the EIO-LCA tool developed at Carnegie Mellon University (28). In order to use this tool, economic values for coal transportation were needed. In 1997, the latest year for which the EIO-LCA tool has data, 84% of coal was transported via rail, 11% via barge, and 5% via truck. The cost for rail transport, barge, and truck transport was 13.9 mills/ton-mile, 9.5 mills/ton-mile, and 142.7 mills/ton-mile respectively (10). For a million ton-miles of coal transported, EIO-LCA estimates that 43.6 tons of CO₂ equivalents are emitted from rail transportation, 5.89 tons of CO₂ equivalents from water transportation, and 69 tons of CO₂ equivalents from truck transportation (28). These emissions were then converted to an emission factor by using the average travel distance of coal in each mode (796, 337, and 38 miles by rail, barge, and truck respectively), the weighted average U.S. coal heat content of 10,520 Btu/lb (27) and the coal production data for 1997, shown above.

The energy consumption data used to develop carbon emissions from the mining life cycle stage were used to develop SO_x and NO_x emission factors for coal. AP 42

emissions factors for off-road vehicles, natural gas turbines, reciprocating engines, light duty gasoline trucks, large stationary diesel engines, and gasoline engines were used to develop this range of emission factors (16,29). In addition, the average emission factors from electricity generation in 1997 (3.92 lbs NO_x/MWh and 7.86 lbs SO_2/MWh (15)) were used in order to include the emissions from the electricity used in mines.

 SO_x and NO_x emissions for coal transportation were again calculated using EIO-LCA (28). EIO-LCA estimates that a million ton-miles of coal transported via rail results in emissions of 0.02 tons of SO_x and 0.4 tons of NO_x . A million ton-miles of coal transported via water would emit 0.07 tons of SO_x , and 0.36 tons of NO_x . Finally, a million ton-miles of coal transported via truck would emit 0.06 tons of SO_x , and 1.42 tons of NO_x (28). These data were added to emissions from mines to find the total SO_x and NO_x emission factors for the upstream stages of the coal life cycle.

2.2.4 Upstream Emissions from SNG

Performance characteristics for two SNG plants are given in Table 8. Using the efficiencies given here, emissions from coal mining, processing and transportation previously obtained were converted to pounds of CO₂ equiv./MMBtu of SNG. The data were also used to calculate the emissions at the gasification-methanation plant using a coal carbon content of 0.029 tons/MMBtu and a calculated SNG storage fraction of 37% (3). Finally, the emissions from transmission, storage, distribution and combustion of SNG are the same as for all other natural gas.

	Case 1 (30)	Case 2 (31)
SNG Output (1. mcf/day and 2. MMBtu/hr)	250	1,739
Efficiency without CCS (HHV)	57%	60%
Efficiency with CCS (HHV)	50%	52%

Table 8: SNG Plant Performance Ch	naracteristics
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In order to develop the SO_x and NO_x emissions from the life cycle of SNG, the emissions from coal mining and transport developed in the previous section in pounds per MMBtu of coal were converted to pounds per MMBtu of SNG using the efficiencies previously discussed. In addition, the emissions from natural gas transmission and storage were assumed to represent emissions from these life cycle stages of SNG. The emissions from the gasification-methanation plant were taken from emission data for an Integrated Coal Gasification Combine Cycle (IGCC) plant, which operates with a similar process. Bergerson (32) reports SO_x emissions factors from IGCC between 0.023 and 0.15 lbs/MMBtu coal (0.026 to 0.17 lbs/MMBtu of coal if there is carbon capture), and a NO_x emission factor of 0.0226 lbs/MMBtu coal (0.0228 lbs/MMBtu of coal if there is carbon capture). These were converted to lbs/MMBtu of SNG using the same efficiencies previously described.

2.2.5 Summary of Emissions from Fuel Upstream Stages

Table 9 summarizes air emission factors for all fuels. The emission factors presented in this section are the average emission rate relative to units of fuel produced, without considering the efficiency of using these fuels. These emission factors can later be used to develop total inventories of air emissions from the annual consumption of each fuel.

Note that there are two different emission factors for SNG. In one case, no carbon capture and sequestration (CCS) is performed at the gasification-methanation stage. When CCS is performed at the gasification-methanation plant, an energy penalty is incurred. It was assumed that the energy penalty observed at IGCC plants with CCS (16%) is representative of the energy penalty at the SNG gasification-methanation plant (33). CCS could also be performed at power plants, as discussed in the next chapter.

It is also very important to note that the emission factors shown in Table 9 are not comparable to each other, since one Btu of coal does not generate the same amount of
electricity or liquid fuels as one Btu of natural gas or SNG. These emission factors can be transformed to comparable units, namely lbs/MWh of electricity produced or lbs/bbl of liquid fuel, by taking into consideration the efficiency of use.

 Table 9: Upstream Air Emission Factors (units: lbs/MMBtu of Fuel Produced)

Pollutant	North American Natural Gas		LN	LNG Coal		bal	SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
GHG (CO ₂ Equiv.)	15.3	20.1	29.6	72.3	8.2	16.4	240	286	45.2	65.2
SO _x	0.006	0.030	0.016	0.145	0.007	0.029	0.051	0.316	0.064	0.400
NO _x	0.009	0.342	0.022	0.831	0.030	0.535	0.090	0.234	0.104	0.253

Figure 5 through Figure 7 show the allocation of GHG emissions reported in Table 9 for each life cycle stage for globally sourced natural gas.



Figure 5: North American Gas Life Cycle GHG Emission Factors (Units: lbs CO₂ Equivalent/MMBtu).



Figure 6: LNG Life Cycle GHG Emission Factors (Units: lbs CO₂ Equivalent/MMBtu).



Figure 7: SNG Life Cycle GHG Emission Factors (Units: lbs CO₂ Equivalent/MMBtu).

3 COMPARING COAL AND GLOBALLY SOURCED NATURAL GAS FOR ELECTRICITY GENERATION²

The previous chapter summarized the mine/well-to-plant emissions of coal and globally sourced natural gas. These emissions were given in units of pounds per million Btu of fuel. Since the efficiency of coal and natural gas power plants are different, the emission factors reported in Chapter 2 are not comparable. In this chapter, the emissions previously developed are used to determine life cycle GHG emissions of electricity generated with coal and with globally sources natural gas in order to better understand which fuel is better suited for this use.

In 2006 total electricity generation in the U.S. was approximately 4,000 billion kWh. GHG emissions from this sector accounted for approximately 35% of the total U.S. GHG emissions. That year, 49% of electricity generation was fueled by coal, while 20% was fueled by natural gas (34). Assuming no significant policy changes, by 2020, DOE/EIA expects that generation will increase to 4,750 billion kWh, with coal fueling 52% of this generation, and natural gas fueling 16%. In this forecast, after 2020, the percentage generation fueled by natural gas starts to decrease and by 2030 natural gas fuels 11% of the total generation of 5,400 billion kWh. By then, coal fuels almost 60% of this generation. Although the percentage generation fueled by natural gas total natural gas generation fueles almost 60% of this generation. Although the percentage generation fueled by natural gas in this forecast decreases in the next 25 years, total natural gas generation increases from 500 billion kWh in 2005 to 610 billion kWh in 2030 (1). GHG emissions from this sector are also expected to increase in the next 20 years. As mentioned before, some assumption in the EIA forecasts can be questionable, and they are used here to help "paint a picture" of the energy future. The specific numbers in these forecasts, however, do not change the results of the analysis presented in the following paragraphs.

² Much of the text from this chapter is based on the following published paper: Jaramillo;, P.; Griffin;, W. M.; Matthews, H. S., "Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation." Environmental Science and Technology 2007, 41, 6290-6296.

The previous chapter summarized the upstream of combustion emissions of coal and globally sourced natural gas. The combustion of these fuels for electricity generation adds 120 pounds of CO_2 Equivalents per MMBtu to the life cycle of globally sourced natural gas (domestic natural gas, LNG, and SNG), and 205 pounds of CO_2 Equivalents per MMBtu to the life cycle of coal. To complete the life cycle picture of the fuels, SO_x and NO_x emissions at the power plant need to also be included, as described in the following sections.

Coal and natural gas power plants have different efficiencies, so one MMBtu of coal does not generate the same amount of electricity as one MMBtu of natural gas/LNG/SNG. For this reason, emission factors previously reported were converted to pounds of pollutant per MWh of electricity generated. This conversion is done using the efficiency of natural gas and coal power plants. I analyzed the case where electricity is generated in currently operating coal and natural gas power plants, and in case where they are used in advanced technology power plants.

3.1 Comparing Fuel Life Cycle Emissions for Fuels Used at Currently Operating Power Plants

Figure 8 shows the distribution of the efficiencies of currently operating power plants, obtained using the cumulative distribution function of EIA 2003 electricity generation data for all utility plants (35). As illustrated in Figure 8, the median efficiency for natural gas plants is higher than the median efficiency for coal plants. These ranges of efficiencies were used to convert the emission factors previously presented (in lbs/ MMBtu of fuel) to lbs/MWh.



Figure 8: Efficiencies of Natural Gas and Coal Plants. The ranges presented in this figure represent the 5th and 95th percentile of the cumulative distribution function of EIA 2003 electricity generation data for all utility plants (35).

The life cycle GHG emissions factors of natural gas, LNG, coal and SNG described in before were converted to a lower and upper bound emission factor from coal and natural gas power plants using these efficiency ranges. Figure 9 shows the final bounds for the emission factors for each fuel cycle. The life cycle for each fuel use includes fuel combustion at a power plant. The combustion only emissions for each fuel are shown for comparison. The solid horizontal line shown represents the current average GHG emission factor for U.S. electricity generation (15). Note that in this graph no carbon capture and storage (CCS) is performed at any stage of the lifecycle. A scenario where CCS is performed at power plants as well as in gasification-methanation plants will be discussed in the following section.



Figure 9: Fuel Combustion and Life Cycle GHG Emissions for Current Power Plants. The ranges presented in this figure represent the variability/uncertainty associated with the upstream emissions of coal and natural gas, as well as the variability of the efficiency of the power plants that use these fuels.

It can be seen that combustion emissions from coal-fired power plants are higher than from natural gas: the midpoint between the lower and upper bound emission factors for coal combustion is approximately 2,100 lbs CO₂ Equivalents/MWh, while the midpoint for natural gas combustions is approximately 1,100 lbs CO₂ Equivalent/MWh. This reflects the known environmental advantages from combustion of natural gas over coal. Figure 9 also shows that the life cycle GHG emissions of electricity generated with coal is dominated by combustion and adding the upstream life cycle stages does not change the emission factor significantly, with the midpoint between the lower and upper bound life cycle emission factors being 2,270 lbs CO₂ Equivalent/MWh. For natural gas-fired power plants the emissions from the upstream stages of the natural gas life cycle are more significant, especially if the natural gas used is synthetically produced from coal (SNG). The midpoint life cycle emission factors for domestic natural gas is 1,250 lbs CO₂ Equivalent/MWh; for LNG and SNG it is 1,600 lbs CO₂ Equivalent/MWh and 3,550 lbs CO₂ Equivalent/MWh, respectively. SNG has much higher emission factors than the other fuels because of efficiency losses throughout the system. It is also interesting to note that the range of life cycle GHG emissions of electricity generated with LNG is

significantly closer to the range of emissions from coal than the life cycle emissions of natural gas produced in North America. The upper bound life cycle emission factor for LNG is 2,400 lbs CO₂ Equivalent/MWh, while the upper bound life cycle emission factor for coal is 2,550 lbs CO₂ Equivalent/MWh.

In order to compare emissions of SO_x and NO_x from all life cycles, the upstream emission factors and the power plant efficiencies previously discussed are used. Emissions of these pollutants from coal and natural gas power plants in operation in 2003 were obtained from EGRID (36). Table 10 shows life cycle emissions for each fuel obtained by adding the combustion emissions from EGRID to the transformed upstream emissions. The current average SO_x and NO_x emission factors for electricity generated in the U.S are also shown (15).

1	Fuol	SO _x (lbs	s/MWh)	NO _x (lbs/MWh)		
I uci		Min	Max	Min	Max	
Current Electricity Mix		6.04		2.96		
Coal	Combustion	1.54	25.5	2.56	9.08	
	Life cycle	1.60	25.8	2.83	9.69	
Natural	Combustion	0.00	1.13	0.12	5.20	
Gas	Life cycle	0.04	1.49	0.17	9.40	
LNG	Life cycle	0.094	2.93	0.25	15.4	
SNG	Life cycle	0.30	3.88	0.65	8.08	

Table 10: SO_x and NO_x Combustion and Life cycle Emission Factors for Current Power Plants

It can be seen that coal has significantly larger SO_x emissions than natural gas, LNG, or SNG. This is expected since the sulfur content of coal is much higher than the sulfur content of other fuels. SNG, which is produced from coal, does not have high sulfur emissions because the sulfur from coal must be removed before the methanation process.

For NO_x , it can be seen that the upstream stages of domestic natural gas, LNG and even SNG make a significant contribution to the total life cycle emissions. These upstream NO_x emissions come from the combustion of fuels used to run the natural gas system: for domestic natural gas, production is the largest contributor to these emissions; for LNG most NO_x upstream emissions come form the liquefaction plant; finally for SNG most upstream NO_x emissions come from the gasification-methanation plant.

3.2 Comparing Fuel Life Cycle Emissions for Fuels Used with Advanced Technologies

According to the U.S. DOE, by 2025 65 GW of inefficient facilities will be retired, while 260 GW of new capacity will be installed (11). Advanced pulverized coal (PC), integrated coal gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) power plants could be installed. PC, IGCC and NGCC plants are generally more efficient (average efficiencies of 39%, 38% and 50%, respectively (33)) than the current fleet of power plants. In addition, CCS could be performed with these newer technologies. Experts believe that sequestration of 90% of the carbon will be technologically and economically feasible in the next 20 years (5,33). Having CCS at PC, IGCC and NGCC plants decreases the efficiency of the plants to average of 30%, 33% and 43% respectively (33).

Figure 10 was developed using the revised efficiencies for advanced technologies and the GHG emission factors (in lbs/MMBtu) described in the Chapter 2.2. This figure represents total life cycle emissions for electricity generated with each fuel. The emissions for each technology are shown with and without CCS. In the case of SNG with CCS, capture is performed at both the gasification-methanation plant and at the power plant. The solid horizontal line shown represents the current average GHG emission factor for electricity generation in the United States (15). The upper and lower bound emissions in this figure are closer together than the upper and lower bounds in Figure 9, because only one power plant efficiency value is used, while for Figure 9 the upper and

lower bound efficiency from all currently operating power plants was used (this is especially obvious for the domestic natural gas (NGCC) cases). It can be seen that, in general, life cycle GHG emissions of electricity generated with the fuels without CCS would decrease slightly compared to emissions from current power plants (due to efficiency gains). The most efficient natural gas plant currently in operation, however, could have slightly lower emissions than the lower bound for NGCC, LNGG, and SNGCC, due to efficiency differences. Three of the cases, however (PC, IGCC, and SNGCC), would still have higher emissions than the current emissions from power plants. If CCS were used, however, there would be a significant reduction in emissions for all cases. In addition the midpoint between upper and lower bound emissions from all fuels are closer together, as can be seen in Figure 11. This figure also shows how the upstream from combustion emissions of fuels become significant contributors to the life-cycle emission factors when CCS is used.



Figure 10: Fuel GHG Life Cycle Emissions Using Advanced Technologies. The ranges presented in this figure only represent the variability/uncertainty associated with the upstream emissions of coal and natural gas. PC: Pulverized Coal. IGCC: Integrated Gasification Combined Cycle. NGCC: Natural Gas Combined Cycle. LNGCC: Liquefied Natural Gas Combined Cycle. SNGCC: Synthetic Natural Gas Combined Cycle. CCS: Carbon Capture and Sequestration.



Figure 11: Midpoint Life Cycle GHG Emissions Using Advanced Technologies with 90% Carbon Capture and Sequestration. The error bars presented in this figure only represent the variability/uncertainty associated with the upstream emissions of coal and natural gas. PC: Pulverized Coal. IGCC: Integrated Gasification Combined Cycle. NGCC: Natural Gas Combined Cycle. LNGCC: Liquefied Natural Gas Combined Cycle. SNGCC: Synthetic Natural Gas Combined Cycle.

The results presented in Figure 11 can be very dependant on the CCS rate. The CCS rate where electricity generated with LNG would have same life cycle GHG emissions as electricity generated with coal in an IGCC plant was determined. To do this, the IECM software (37) was used to determine the relationship between the carbon capture rate and the efficiency of the plant. IECM does not have data for an SNG plant, so it was not possible to include SNG in the calculation. Figure 12, shows the results of a regression relating CCS rate and efficiency.



Figure 12: CCS Rate and Efficiency of IGCC and NGCC Plants (37).

Equation 1, which uses the regression equations shown in Figure 12, was used to calculate the CCS efficiency where LNG in a NGCC plant and coal in an IGCC plant would have the same life cycle GHG emissions.

Equation 1: CCS Rate where IGCC and LNGCC Have Same Life Cycle GHG Emissions

$$\frac{\left[(9,46.67)(x)+7,113.8\right]\left[(120)(x)+y\right]}{1,000} = \frac{\left[(1,503.8)(x)+9,202.8\right]\left[(205)(x)+z\right]}{1,000}$$

where x is the CCS rate, y is the upstream GHG emission factor of LNG in lb/MMBtu, and z is the upstream GHG emission factor of coal in lb/MMBtu. Since there is a range of y and z values (as described in Chapter 2), x at which both sides of the equation are equal (and above which IGCC will have lower life cycle GHG emissions than LNGCC) will vary throughout this range, as shown in Table 11.

Upstream En	nission Factors	CCS Rate above which
(lbs CO ₂ Eq	uiv. /MMBtu)	IGCC < LNGCC
У	Z	X
46.5	11.6	79%
29.57	8.2	88%
72.27	16.4	66%
72.27	8.2	59%
29.57	16.4	95%

Table 11: CCS Rate above which Coal in IGCC has Lower Life Cycle GHGEmission Factors than LNG in a NGCC

Life cycle emissions of SO_x and NO_x for electricity generated using advanced technologies were found using the same procedure as for conventional power plants. Table 13 was developed using the upstream SO_x and NO_x emission factors for coal and globally sourced natural gas obtained in the Chapter 2.2, and the combustion emissions reported by Bergerson (32) for PC and IGCC plants and by Rubin et al for NGCC plants (33). These reported combustion emissions are presented in the Table 12.

 Table 12: Combustion Emissions from Advanced Power Plants.

Fuol/Pollutont	SO _x (lb	s/MWh)	NO _x (lbs/MWh)		
r'uci/i onutant	Min	Max	Min	Max	
PC w/o CCS	0.17	1.28	1.16	2.00	
PC w/ CCS	0.00	0.01	1.56	3.00	
IGCC w/o CCS	0.20	1.30	0.20	0.20	
IGCC w/ CCS	0.24	1.52	0.20	0.20	
NGCC w/o CCS	0.00	0.00	0.24	0.24	
NGCC w/ CCS	0.00	0.00	0.29	0.29	

Fuel		SO _x (lbs	s/MWh)	NO _x (lbs/MWh)		
	I uci		Max	Min	Max	
Current Electricity Mix		6.	04	2.96		
	PC w/o CCS	0.24	1.54	1.42	2.46	
Coal	PC w/ CCS	0.08	0.34	1.90	3.61	
	IGCC w/o CCS	0.27	1.57	0.47	0.70	
	IGCC w/ CCS	0.32	1.83	0.54	0.78	
Natural	NGCC w/o CCS	0.04	0.20	0.30	2.57	
Gas	NGCC w/ CCS	0.05	0.24	0.36	3.01	
	NGCC w/o CCS	0.25	1.04	0.39	5.89	
LNG	NGCC w/ CCS	0.30	1.23	0.46	6.91	
SNC	NGCC w/o CCS	0.35	2.15	0.88	1.85	
SNG	NGCC w/ CCS	0.45	2.80	1.03	2.18	

Table 13: SO_x and NO_x Life cycle Emission Factors for Advanced Technologies

As can be seen from Table 13, if advanced technologies are used, a significant reduction of NO_x and SO_x emissions could result, even if CCS is not available. It is interesting also to note that a PC plant with CCS could have lower life cycle emissions than an IGCC plant with CCS. In the PC case all sulfur is removed through flue gas desulphurization. The removed sulfur compounds are then solidified and disposed of or sold as gypsum. In an IGCC plant with CCS, sulfur is removed from the syngas before combustion. In these plants, however, instead of solidifying the sulfur compounds removed and disposing them, the elemental sulfur is recovered in a process that generates some additional SO_x emissions (32). For NO_x , only LNG has higher life cycle emissions than what is generated at current power plants.

3.3 Discussion of Results

In this chapter, I analyzed the effects of the additional air emissions from the LNG/SNG life cycle on the overall emissions from electricity generation in the U.S. It was found that with current electricity generation technologies, natural gas life cycle GHG emissions are generally lower than coal life cycle emissions, even when increased LNG imports are included. However LNG imports decrease the difference between GHG

emissions from coal and natural gas. SNG has higher life cycle GHG emission than coal, domestic natural gas or LNG. It is also important to note that upstream GHG emissions of NG/LNG/SNG have a higher impact in the total life cycle emissions than upstream coal emissions do on coal's total life cycle emissions. This is a significant point when considering a carbon-constrained future in which combustion emissions are reduced.

For emissions of SO_x , it was found that with current electricity generation technologies, coal has significantly higher life cycle emissions than any other fuel due to very high emissions at current power plants. For NO_x, however, this pattern is different. I find that with current electricity generation technologies, LNG could have the highest life cycle NO_x emissions (since emissions from liquefaction and regasification are significant), and that even natural gas produced in North America could have very similar life cycle NO_x emissions to coal. It is important to note, that while GHG emissions contribute to a global problem, SO_x and NO_x are local pollutants and U.S. policy makers may not give much weight to emissions of these pollutants in other countries.

In the future, as newer generation technologies and CCS are installed, the overall life cycle GHG emissions from electricity generated with coal, domestic natural gas, LNG or SNG would be similar. Most important is that all fuels with advanced combustion technologies and CCS have lower life cycle GHG emission factors than the current average emission factor from electricity generation. For SO_x it was found that coal and SNG would have the largest life cycle emissions, but all fuels have lower life cycle SO_x emissions than the current average emissions from electricity generation. For NO_x, LNG would have the highest life cycle emissions and would be the only fuel that could have higher emission than the current average emission factor from electricity generation, even with advanced power plant design.

I suggest that advanced technologies are important and should be taken into account when examining the possibility of doing major investments in LNG or SNG infrastructure. Power generators hope that the price of natural gas will decrease as alternative sources of natural gas are added to the U.S. mix, so they can recover the

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investment made in natural gas plants that are currently producing well under capacity. I suggest that these investments should instead be viewed as sunk costs. Thus, it is important to re-evaluate whether investing billions of dollars in LNG/SNG infrastructure will lock us into an undesirable energy path that could make future energy decisions costlier than ever expected and increase the environmental burden from our energy infrastructure.

This analysis was performed from a U.S. perspective, however some general ideas can be summarized for other countries. From the perspective of countries rich in coal but without natural gas resources, the conclusion does not change: It is better to promote clean coal technologies for electricity generation than to import LNG. This is not the case for countries that have readily available domestic supply of natural gas that does not have to be converted into LNG for transport. In these countries, natural gas based electricity is better, in terms of GHG emissions, than coal. It is harder to extend the results of this U.S.-centric analysis to countries that do not have coal or natural gas, as both fuels would have to be transported via ocean tanker/barges. I would presume, however, that since the energy density of coal is higher than the energy density of LNG, the emissions associated with the oceanic transport would have a lower contribution to the life cycle of coal than to the life cycle of LNG. I would even venture to say that with advanced coal technologies with 90% CCS, electricity produced with imported coal would still have lower life cycle GHG emissions than electricity produced with imported LNG. Future analysis could be performed to verify this hypothesis.

4 COMPARING COAL AND GLOBALLY SOURCED NATURAL GAS FOR THE PRODUCTION OF TRANSPORTATION FUELS

This chapter describes the third stage of this research, where I explore whether is better to use coal or natural gas for the production of transportation fuels by comparing the life cycle GHG emissions of Fischer-Tropsch (FT) liquid fuels, and compressed natural gas.

EIA's forecasts suggest that by 2030, petroleum demand in the U.S. will be 27 million barrels per day, 73% of which will be used by the transportation sector. By that same year, over 70% of petroleum and petroleum related products will be imported from oilrich countries, some of which have highly volatile political and social situations (1). In addition to this dependency on a foreign fuel, petroleum combustion from the transportation sector is and will remain one of the largest sources of CO₂ emissions in the country. EPA estimates that in 2002, 31% of the total U.S. CO₂ emissions came from the transportation sector (3). These numbers are mentioned here as a reference, they do not, however, affect the conclusions that will be presented in this chapter.

4.1 Comparing Coal and Globally Sourced Natural Gas for the Production of Fischer-Tropsch Fuels

As a response to concerns about consumption of petroleum, interest on alternative fuel sources for the transportation sector has risen. Transportation fuels produced from coal or natural gas via the Fischer-Tropsch (FT) process have been suggested as an alternative source. The U.S. is rich in coal and the technology to produce coal-to-liquid (CTL) fuels already exists and it has been widely used in South Africa since the 1970s. Natural gas is not as abundant in the U.S. as coal, but it is perceived to be less carbon intensive.

Construction of plants to produce gas-to-liquid (GTL) fuels for export is being considered in Qatar and Malaysia (38).

CTL fuels, and to a lesser extent, GTL fuels, could help reduce the U.S. dependence on foreign sources of petroleum. It is not clear, however, what the impacts of consumption of these fuels would be on efforts to reduce greenhouse gas (GHG) emissions. In this chapter a life cycle analysis is performed in order to help answer this question. Direct air emissions from the processes during the life cycle will be considered, as well as emissions from the combustion of fuels and electricity used to run the processes. A comparison with petroleum-based fuels will be presented, in order to have a better understanding of the advantages or disadvantages of using coal and natural gas to produce transportation fuels.

4.1.1 Life Cycle of FT-Liquid Fuels

There are several pathways for the production of FT-fuels for U.S. consumption, and so there are several life cycles to consider. The life cycle of FT-fuels produced from coal starts with the coal mining and processing. The coal is then transported to the CTL plant, where the coal is gasified to produce syngas (CO and H₂). Syngas is converted by the FT-process to transportation compatible liquid fuels, diesel and gasoline. The efficiency of the process, types and amount fuels produced, can be influenced by catalyst choice (39). From the CTL plant, the gasoline and diesel produced are transported to fueling stations, after which the fuels are used in standard petroleum-based gasoline and diesel vehicles.

For GTL fuels, the life cycle starts with the extraction and processing of natural gas. If domestic natural gas is used for the production of GTL fuels, the natural gas is delivered to the GTL plant via pipeline. At the GTL plant, syngas is produced through a combination of steam methane reforming and non-catalytic partial oxidation. Just like in the CTL plant, the syngas is then converted into gasoline and diesel in a FT-reactor. The diesel and gasoline are then transported to consumers and combusted in vehicles. The life cycle of GTL fuels produced in foreign countries and delivered to the U.S. would be similar to the life cycle of GTL fuels produced with domestic natural gas, except for the need to transport the refined diesel and gasoline to the U.S. Here it was assumes that transportation would occur via ocean tanker.

GTL fuels could also be produced in the U.S. using imported liquefied natural gas (LNG). If LNG is used, there are additional stages in the life cycle of the GTL fuels. After the natural gas is extracted and processed in a foreign country, it is liquefied, transported via tanker to the U.S. and regasified. It is then placed in the U.S. transmission system that delivers it to the GTL plant. Figure 13 graphically shows the life cycle stages of FT-fuels. Notice that this figure includes the life cycle stages upstream from the FT-Plant, which were described in detail in Chapter 2.



Figure 13: Life Cycle of FT-Liquid Fuels from Coal and Natural Gas

The analysis presented here includes five pathways for FT-liquid production and supply: two coal-to-liquid (CTL) pathways and three gas-to-liquid (GTL) pathways, as described in Table 14.

Pathway	Description
Benchmark CTL Plant	In this pathway slightly more diesel (53 %)
	than gasoline (44%) is produced. The rest
	is propane (39).
Maximum Gasoline Production CTL	The CTL plant in this pathway is upgraded
Plant	with catalysts that transform some diesel
	and waxes produced in the conventional
	plant into additional gasoline changing the
	product ratio from the benchmark CTL
	plant to 20% diesel, 73% gasoline and, 7%
	propylene and propane (39).
GTL Plant: Domestic Natural Gas	The conventional GTL plant, produces
	62% diesel, 35% gasoline, and 3% propane
	(39). This plant is built in the U.S. and fed
	with domestic natural gas.
GTL Plant: LNG	The conventional GTL plant as above but it
	imported LNG as a feedstock.
Imported GTL fuels	The conventional GTL plant is built in
	Qatar or Malaysia and the refined fuels are
	imported by the U.S.

Table 14: FT-Liquid Production and Supply Pathways

The boundary of this life cycle analysis includes GHG emissions from the production, processing, and transport of the feedstock fuels (coal and globally sourced natural gas). It also includes the emissions at the FT-plant, the life cycle emissions from the electricity used in the plant, emissions from transporting the refined products, and the liquid fuel combustion emissions. This analysis does not include emissions related to the construction of the plants or any other infrastructure.

The method for calculating emissions from the production, processing and transport of coal, domestic natural gas, and LNG was described in Section 2.2. Values used for emissions from mining, processing and transporting coal range between 8.21 and 16.4 pounds of CO₂ equivalents per million Btu (lb CO₂ equiv./MMBtu). For domestic natural gas, the upstream use emissions ranged between 15.0 and 20.0 lb CO₂ equiv./MMBtu. For LNG these emissions ranged between 30.0 to 72.1 lb CO₂ equiv./MMBtu (40). For the case where the GTL fuels are produced in Qatar or Malaysia, the emissions for domestic natural gas are assumed to be representative of the emissions from production, processing, and transport of the gas used at these foreign plants. All these feedstock emission factors are converted to lb CO₂ equiv./MMBtu of FT-liquid by using the efficiencies of FT-plants.

Table 15 shows the inputs and outputs from these CTL and GTL plants. The data were used to estimate the GHG emissions from the plants. The benchmark design CTL plant produces slightly more diesel than gasoline with an overall energy efficiency of 54% high heating value (HHV). This benchmark CTL plant can be modified to upgrade some of the diesel and waxes to produce more gasoline, slightly lowering the overall energy efficiency to 52% HHV. Note that Illinois No. 6 coal was used in the Department of Energy studies to model the CTL plants (39), and all the analysis performed is based on the production of CTL fuels with higher energy content coal such as this. If waste coal, which has a lower heat content, were used to produce CTL fuels, the results of the analysis presented here would differ. In a GTL plant more diesel than gasoline is produced, and the plant has an overall efficiency of 55% HHV.

		CTL		
INPUTS		Benchmark Design	Maximum Gasoline Production	GTL Plant
Coal (tons/day	r)	18,575	18,575	0
Natural Gas (MMc	ef/hr)	0	0	17
Methanol (tons/d	lay)	0	209	0
Butanes (tons/da	ay)	320	440	35
Purchased Electricity (no CCS) (MWh/day)		1,300	1,350	-590
Purchased Electricity	Min	3,180	3,230	-155
(90% CCS) (MWh/day)	Max	4,590	4,630	170
		CTL		
OUTPUTS		Benchmark Design	Maximum Gasoline Production	GTL Plant
Propylene (MMBti	ı/day)	0	12,300	0
Propane (LPG) (MMBtu/day)		7	6,120	6,550
Gasoline (MMBtu/day)		115,000	187,000	145,000
Diesel (MMBtu/c	lay)	137,000	52,000	231,000
Carbon Lost (tons	/day)	7,820	7,815	1,825

Table 15: Inputs and Outputs of CTL and GTL plants (39)

CTL and GTL plants are perfect candidates for carbon capture and sequestration (CCS). For both plant designs, CO_2 passing from the gasification reactor for a CTL plant or the steam methane reformer for a GTL facility will interfere with the downstream FTreaction. Thus, all designs necessarily separate CO_2 from the gas stream before it enters the FT-reactors. Only the addition of CO_2 compression is required to make the facilities CCS capable.

The Benchmark CTL plant design, without CCS, purchases electricity from the grid, while the GTL plant design generates enough electricity for its own use, and some excess power is sold (39). Installing CO₂ compression in these plants in order to achieve 90% CCS would demand additional power: between 80 and 140 MWh per metric ton of CO₂

compressed (41). Table 15 shows electricity purchases for the different plants for two cases: no carbon capture and storage (CCS), and with CCS. In addition to the direct power requirements of the plant (as shown in Table 15), 9% losses from the transmission of this power (42) are added to obtain the total power generation requirements for CTL and GTL plants. Emissions from the life cycle production of this power are also included in the analysis (this electricity life cycle includes the emissions from the upstream stages of the life cycle of the fuels used as described in Chapter 2, and the emissions from the combustion at currently operating power plants). Currently, approximately 50% of the U.S electricity is generated with coal, 20% with natural gas, and the rest with low-carbon sources (43). Using this electricity generation mix and the emission factors given in Chapter 3, the electricity life cycle emission factor is found to be between 1,310 and 1,375 pounds of CO₂ equivalents per MWh. This range is used to find what I call worstcase scenario emissions from CTL and GTL production. These are not really the worstcase emissions, since I could assume that the electricity comes from the oldest, most inefficient coal power plants. This latter, however, might be a very extreme assumption that would be hard to defend, so the more conservative assumption is used. In the bestcase scenario, it is assumed that the power purchased by CTL and GTL plants is generated using zero-carbon sources, such as nuclear or carbon free renewables.

In a GTL plant without CCS, surplus power can be sold. In this case the plant would receive an emission offset. Emission offsets are given as a credit for replacing grid electricity that may be generated with more carbon intensive resources. This emission offset is calculated by subtracting the emissions allocated (as described below) to the electricity generated at the plant from the emissions that would result if the same electricity were generated with the average power mix.

Adding the emission factors from the production, processing, and transport of the feedstock fuels to the emission factors from the FT-plants and from the electricity used at these plants results in a "well-to-plant" emission factor. Since CTL and GTL plants produce different products in different amounts, allocation of emissions must be performed. CTL and GTL plants are similar to petroleum refineries, and they produce the

same liquid fuels that are produced in a petroleum refinery. Wang et al (44) have studied allocation methods in petroleum refineries. They suggest allocation should be performed based on energy and mass data for specific refining processes within a refinery. They argue that this allocation method accounts for differences in energy use and emissions associated with the production of the different products at each refining stage, differences that are ignored in a refinery-level allocation. However, process specific data for CTL and GTL plants is not widely available and is likely proprietary in most cases. For this analysis, some process level data was available (39) but it was incomplete, resulting in a detailed mass balance but no detailed energy balance. For this reason, the refinery level allocation used by Argonne's Greenhouse gases, Regulated Emissions, and Energy Use in Transportation (GREET) model was used (44,45). Refinery level allocation can be performed based on mass, volume, energy content, or market value of the products. Allocation based on all these parameters was considered for this study. Figure 14 and Figure 15 show the results of several allocations to diesel and gasoline of the well-toplant emissions (for plants with no CCS that use the current electricity mix). In the GTL plant, electricity is a co-product and for the purpose of allocation has essentially no mass and occupies no volume, so allocation by mass and volume was not possible. Average 2006 price data for co-products comes from the U.S Department of Energy (46,47): \$2.13/gallon of gasoline, \$2.08/gallon of diesel, \$1.36/gallon of liquid petroleum gases (LPGs), and 8.37 cents/kWh of electricity.

As can be seen in Figure 14 and Figure 15, the units used for allocation had minimal impact on the allocation results. The same allocation results are observed (but not shown) for the case where CCS is performed at the plant and the electricity purchased is produced with a low-carbon source. Thus, for the rest of the analysis allocation is based on energy content of the products.



Figure 14: Allocated Well-to-Plant Emissions – Gasoline



Figure 15: Allocated Well-to-Plant Emissions – Diesel

Emissions from liquid fuel transport and liquid fuel combustion must be added to the allocated well-to-plant emissions in order to obtain the full life cycle, "well-to-wheel"

emissions. Liquid fuels in the U.S. are transported via barges, pipeline, rail, and truck. Table 16 shows the percentages of fuel transported by each mode. Notice that these percentages can be derived either by weights transported (as done in the GREET model (45)) or by ton-mile transported, without any significant changes in the results. Total emissions from liquid fuel transport within the U.S. are calculated by multiplying the energy intensity of each mode by the average distance traveled and the carbon content of the fuel used to power the mode, and divided by the energy content of the fuel transported. Table 16 shows the values of these parameters. Note that several energy intensities are given for each mode. They were used to develop ranges of emissions from transportation. One set comes from the assumptions in the GREET model (45), the other comes from the latest Transportation Energy Data Book (14). The distances traveled and the fuels used to power each mode come from GREET (45).

	Trin	Energy Intensity (Btu/ton-mile)		Distance		% Fuels Transported	
Mode	Description	GREET	Trans. Energy Book	Traveled (miles)	Fuels Used	Weight	Ton- miles
Barges	Full Load	403	417	520	100% Diesel	220/2	61%
Darges	Back Haul	307	417	520	10070 Diesei	5570	0170
Pipeline	One Way	253	256	400	20% Diesel, 50% Residual Oil, 30% Natural Gas	60%	29%
Rail	One Way	370	344	800	100% Diesel	7%	4%
Truck	Both Ways	1,028	543	30	100% Diesel	100%	6%

 Table 16: Liquid Fuel Transportation Assumptions (14,45)

In the case where GTL fuels are produced in other countries and imported by the U.S., tanker transport has to be included. Qatar and Malaysia are the two countries that have started investing in a GTL production infrastructure (38), so it was assumed that GTL liquids would be imported from these two countries. The GREET model assumes the energy intensity of petroleum product tankers to be 32 Btu/ton-mile, with diesel fuel

providing this energy (45). Alternatively, the method for calculating ship transport emissions presented by Trozzi et al (48) is used to produce a range of tanker emissions. According to Trozzi et al, a tanker with a bulk weight of 100,000 tons consumes approximately 95 tons of diesel fuel per day and emits 7,000 pounds of CO_2 equivalents per ton of fuel consumed. It was also assumed that such tankers traveling from Qatar and Malaysia travel at an average speed of 14 knots (48).

Gasoline and diesel produced from coal and natural gas have a carbon content of 44.2 and 41.9 pounds of carbon per million Btu, respectively, and an energy content of 0.11 and 0.13 million Btu per gallon, respectively (49). This data was used to determine the emission at the combustion stage.

Figure 16 and Figure 17 show the worst-case well-to-wheel GHG emission factors for gasoline and diesel produced with coal and natural gas. In this worst-case scenario, CCS is not available at the FT-plants. In addition, the current U.S. fuel mix for electricity generation (50% coal, 20% natural gas, and 30% low-carbon sources (43)) is assumed. These graphs include well-to-wheel emission factors for conventional petroleum-based gasoline and diesel, adapted from the GREET model (45) for the assumed vehicle characteristics.

As can be seen in Figure 16 and Figure 17 gasoline and diesel produced from coal could emit more than double the life cycle GHG emissions of petroleum-based gasoline and diesel. If domestic natural gas were used to produce gasoline, or if natural gas-based gasoline is imported from Qatar or Malaysia, an increase in emissions would be seen: between 20% and 30%. If LNG is used, an increase of around 50% in emission factors for both gasoline and diesel could be observed.



Figure 16: Worst-Case, Well-to-Wheel GHG Emissions for Gasoline. These worst-case emission factors assume no CCS at the FT-Plant and the use of electricity from the grid. The error bars presented in this figure only represent the uncertainty/variability associated with the upstream GHG emissions of coal and natural gas. CTL: Coal-to-Liquids. GTL: Gas-to-Liquids. NANG: North American Natural Gas



Figure 17: Worst-Case, Well-to-Wheel GHG Emissions for Diesel. These worst-case emission factors assume no CCS at the FT-Plant and the use of electricity from the grid. The error bars presented in this figure only represent the uncertainty/variability associated with the upstream GHG emissions of coal and natural gas. CTL: Coal-to-Liquids. GTL: Gas-to-Liquids. NANG: North American Natural Gas Figure 18 and Figure 19 show the best-case well-to-wheel GHG emission factors for gasoline and diesel produced with coal and natural gas. In this best-case scenario, CCS is available at the FT-plants. In addition, a low carbon electricity source is assumed. It is unlikely, that such a source of electricity would be used at FT-plants. This assumption is used, however, to show what could be the best GHG emission reduction achievable with FT-fuels. In all cases, except when LNG is used as a feedstock, a very slight reduction (less than 4%) in emissions associated with the life cycle of gasoline could be observed. In the case of diesel, the use of coal or domestic natural gas could imply a slight increase of less than 3% in GHG emissions compared to petroleum-based diesel. Diesel and gasoline produced from LNG would have higher life cycle GHG emissions than current petroleum-based fuels.



Figure 18: Best-Case, Well-to-Wheel GHG Emissions for Gasoline. These best-case emission factors assume 90% CCS at the FT-Plant and the use of lowcarbon electricity. The error bars presented in this figure only represent the uncertainty/variability associated with the upstream GHG emissions of coal and natural gas. CTL: Coal-to-Liquids. GTL: Gas-to-Liquids. NANG: North American Natural Gas



Figure 19: Best-Case, Well-to-Wheel GHG Emissions for Diesel. These bestcase emission factors assume 90% CCS at the FT-Plant and the use of low-carbon electricity. The error bars presented in this figure only represent the uncertainty/variability associated with the upstream GHG emissions of coal and natural gas. CTL: Coal-to-Liquids. GTL: Gas-to-Liquids. NANG: North American Natural Gas

4.1.2 The Economics of FT-Liquid Fuels from Coal and Natural Gas

In the previous section, it is shown that the use of CTL and GTL fuels is not an emission reduction strategy: at best these fuels would have basically the same life cycle GHG emissions as petroleum-based fuels; LNG derived fuels would likely increase emissions. Energy prices and energy security are, however, two other factors that are leading the U.S. to consider these alternative transportation fuels. CTL fuels and GTL fuel plants have not been built in the U.S. and the international experience with these plans has been very limited. For this reason, real-life cost data for these plants is not widely available and for this analysis only rough estimates and ranges are available. Table 17 shows a levelized cost estimate for these plants, and the assumptions used to develop these costs. Prices for coal and natural gas used were the average price paid by industrial consumers in June 2007. Fixed operation and maintenance (O&M) costs for the plants were obtained

assuming they are 4% of the capital costs (50) and adding an electricity cost based on the electricity consumed by the plants (as presented in Table 15) and a purchase price of electricity of \$0.06/kWh (46,47) . In the CTL plant the increased use of electricity in the CCS plant increased the O&M by 50%. In the GTL plant no significant change is observed because the increase in the electricity demand in a CCS plant is not very significant. Increase in electricity price would increase the O&M costs, however the change is not very significant compared to changes in coal and natural gas prices, so these numbers were assumed to remain constant. A capital charge factor of 15% was used. This charge factor is the same number used by Rubin et al when they calculated the levelized cost of electricity from IGCC plants and NGCC plants (33). Capital costs for the plant were obtained from Tullo, DOE, and SasolChevron (51-53). Fuel costs were obtained from DOE (37,54).

	CTL	CTL	GTL	GTL
	Plant	Plant	Plant	Plant
	(no CCS)	(w/ CCS)	(no CCS)	(w/ CCS)
Plant Capacity Factor	85%	85%	85%	85%
Plant Cost (\$/daily bbl) (51-	\$70.000	\$00,000	\$20,000	\$20,000
53)	\$70,000	\$90,000	\$20,000	\$30,000
Fixed O&M Cost (\$/bbl)	\$10	\$15	\$5	\$5
Price of Feedstock Fuel (\$/ton	\$50	\$50	¢o	¢o
coal or \$/MCF of NG) (37,54)	\$30	\$30	φο	фо
Feedstock Fuel Cost (\$/bbl)	\$18.5	\$18.5	\$73.5	\$73.5
Capital Charge Factor	15%	15%	15%	15%
Levelized Cost (\$/bbl)	\$62	\$77	\$88	\$93
Levelized Cost (\$/gallon)	\$1.5	\$1.8	\$2.1	\$2.2

Table 17:	Levelized	Cost of CTL	and GTL	Fuels
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The levelized costs are not very useful by themselves. They are only meaningful for comparing these CTL and GTL fuel costs with the cost of the fuels they are meant to replace: petroleum-based gasoline and diesel. Even though GTL and CTL plants produced different liquid fuels that could be sold at different prices, with the available data I could only develop an average cost per gallon of liquid fuel produced. To compare

this average number to petroleum diesel and gasoline, an average price for these petroleum-based fuels was developed. Using historic crude oil price data and historic prices of gasoline and diesel (55,56), a regression was performed to relate the average price of EIA's "refiner product to sale for re-sellers" of both gasoline and diesel (used as a proxy for refiner gate prices, as suggested by the DOE) to the refiner acquisition price of crude oil (the price refineries pay for crude oil, which is representative of the market price of crude oil). Figure 20, below, shows the result of this regression. From this regression it was found that at a refiner acquisition cost of \$65 bbl (June 2007 price (56)) the average price of gasoline and diesel is \$2.12 per gallon. Based on these June 2007 prices, CTL liquids could be cheaper than petroleum-based fuels. The cost of GTL fuels would be very similar to the cost of petroleum-derived fuels.



Figure 20: Average Price of Refiner Product to Sale for Re-Sellers vs. Refiner Acquisition Cost

A carbon tax applied to all these fuels (CTL, GTL and petroleum-derived fuels) based on their mid-point life cycle GHG emissions, as reported in the previous sections, would affect the economics of CTL and GTL fuels as compared to petroleum-derived fuels. Figure 21 through Figure 23 show the carbon tax that would be required for petroleumderived fuels to have the same price as CTL and GTL fuels at June 2007 energy prices (\$50/ton coal, \$65/bbl of oil, and \$8/MCF of natural gas). If carbon capture and sequestration is not available at FT-liquid plants, at a carbon tax larger than \$40/ton CO₂, CTL fuels would become more expensive than petroleum-based fuels. For GTL fuels (from any source) any carbon tax would make GTL fuels more expensive than petroleum-based fuels.

If the FT-fuels were produced in the most optimistic scenario previously described (with CCS and using low carbon sources of electricity), CTL fuels would be slightly cheaper than petroleum-derived fuels at any given carbon tax (the graph was extended to \$200/ton CO_2 to confirm that these remained true at very high carbon taxes), GTL fuels produced with domestic sources would have the same price as petroleum-derived fuels, and GTL fuels produced using imported LNG would be more expensive than petroleum-derived fuels.



Figure 21: CTL vs. Petroleum Fuels: June 2007 Energy Prices (\$65/bbl Oil and \$50/ton Coal) and a Carbon Tax.



Figure 22: Domestic NG-GTL vs. Petroleum Fuels: June 2007 Energy Prices (\$65/bbl Oil and \$8/MCF Natural Gas) and a Carbon Tax.



Figure 23: LNG-GTL vs. Petroleum Fuels: June 2007 Energy Prices (\$65/bbl Oil and \$8/MCF Natural Gas) and a Carbon Tax.

The economics of CTL and GTL fuels will vary depending on the price of natural gas, the price of coal, the price of oil, and the carbon tax. The figures presented in Appendix A show the results of a sensitivity analysis performed. Table 18 shows a summary of some results from the Appendix. In this table the feedstock prices (coal or natural gas) required for FT-liquids to be more expensive than petroleum-based fuels are shown for three different carbon taxes and three different oil prices. CTL fuels produced without CCS are not economic at low oil prices, regardless of the carbon price. At high oil prices, CTL become more economically feasible, however if the carbon tax is too high, the economic benefits of high oil prices are reduced. For CTL and GTL fuels produced with domestic resources in the best scenario (CCS and renewable electricity), the carbon tax has no effect on the feedstock prices required for FT-fuels to be more expensive than petroleum-based fuels. The cause of this insensitivity to carbon prices is that in this bestcase scenario, the life cycle emissions from CTL fuels, GTL fuels produced with domestic, and petroleum-based fuels are basically the same. For LNG based GTL fuels, the prices of natural gas do not get unrealistically high before petroleum-fuel are cheaper, even at high oil prices.

Table	18: Feedstock I	Fuel Prices to A	Achieve Break	xeven Cost o	f FT-Fuels	and
	Petroleum-Bas	ed Fuels at Se	veral Carbon	Taxes and C	Dil Prices	

Carbon	Oil	Coal Price (\$/ton)		Domestic (\$/M	NG Price ICF)	LNG Price (\$/MCF)		
Tax (\$/ton)	Price (\$/bbl)	Worst Emissions	Best Emissions	Worst Emissions	Best Emissions	Worst Emissions	Best Emissions	
\$20	\$40	\$0	\$0	\$4.5	\$4	\$4	\$3.5	
	\$80	\$150	\$140	\$10	\$10	\$10	\$9.5	
	\$120	\$300	\$290	\$16	\$15.5	\$15.5	\$15.5	
	\$40	\$0	\$0	\$3.5	\$4	\$2.5	\$2.5	
\$80	\$80	\$60	\$140	\$9.5	\$10	\$8.	\$8.5	
	\$120	\$200	\$290	\$15	\$15.5	\$14	\$14.5	
	\$40	\$0	\$0	\$2.5	\$4	\$0.5	\$1.5	
\$140	\$80	\$0	\$140	\$8.5	\$10	\$6.5	\$7.5	
	\$120	\$120	\$290	\$14.5	\$15.5	\$12.5	\$13.5	

4.1.3 Replacing Petroleum-Derived Fuels with FT-Liquids

So far I have presented the climate change implications of CTL and GTL fuel production use as well as a brief analysis of the economic implications of these fuel. When looking at increasing the production of these alternative fuels, it is also important to consider the impacts this would have in the consumption levels of the feedstock fuels. As an extreme scenario, I have looked at how much coal or natural gas would be required if the U.S. were to replace petroleum-derived fuel demand between 2010 and 2030. The demand projections from the 2007 Annual Energy Outlook were used (1). Forecasting energy demand is a complicated task and forecasts can be very inaccurate, however, the DOE forecasts were used because they are publicly available and used extensively for energy research.

When looking at a CTL plant, there are two options: one, we could build the maximum gasoline production plant, in which case I look at a scenario where we replace 100% of the projected annual demand for petroleum-based gasoline and approximately 50% of the projected diesel demand for each year. Alternatively, the benchmark CTL plant design could be built in order to replace 100% of the projected annual demand for petroleum-based diesel, and approximately 45% of the projected annual demand for petroleum-based gasoline. When considering using GTL liquids, I looked at a scenario in which we replace 100% of the projected annual demand for petroleum-based diesel, and approximately 30% of the projected annual demand for petroleum-based gasoline. These replacement scenarios are better described in Figure 24.



Figure 24: Average Annual Replacement of Petroleum-Derived Fuels by FT-Fuels 2010-2030

Figure 25 and Figure 26 show the increase in coal or natural gas consumption that would be required. It can be seen that by 2030 total coal consumption (obtained by adding the 2007 Annual Energy Outlook projections (1) and the amount for coal need for the CTL plants) would be more than double the projected coal consumption for that year; total natural gas consumption (obtained by adding the 2007 Annual Energy Outlook projections (1) and the amount of natural gas need for the GTL plants) would also be more than double the projected natural gas consumption. The U.S. domestic natural gas supply is not expected to increase in the coming decades, so if GTL plants were to be built, the supply for these plants would likely come from imported sources such as LNG. U.S. coal reserves, on the other hand, are reported to be abundant, often quoted to last 250 years at current consumption rates (57). A 2007 report by the National Research Council (57), states that although coal reserves are probably sufficient to meet coal demand at current rates for the next century, it is not possible to confirm the 250 year supply of these resources in centuries to come becomes more uncertain.


Figure 25: Comparison of Projected Coal Consumption, 2010-2030



Figure 26: Comparison of Projected Natural Gas Consumption, 2010-2030

In addition to coal or natural gas, FT-liquid plants could use significant amounts of electricity, especially if carbon capture and sequestration is performed. Figure 27 shows the increased electricity demand that would result if we wanted to replace petroleum-based and gasoline with CTL and GTL fuels produced in plants with carbon capture and sequestration. It can be seen that GTL fuels would not have a visible impact in electricity demand. CTL fuels, on the other hand, would increase demand for electricity by 400 to 500 billion kWh. This might not seem very significant, however it should be noted that in the best-case scenario for FT-production (which gives us the lowest life cycle GHG emissions, and on which these electricity demand numbers are based), this electricity would have to be produced with a low carbon source. The 2007 Annual Energy Outlook projects that by 2030 total electricity generated with low carbon sources (nuclear and renewable sources) will be around 1,400 billion kWh; so the demand from CTL plants would require electricity from this sources to be 30% to 35% higher than is projected.



Figure 27: Total Electricity Demand Including Demand for Best-Case FT-Liquid Production

4.1.4 Discussion of Results

Alternative transportation fuels are being considered in order to reduce the U.S.'s dependence on foreign sources of petroleum. At the same time concern over GHG emissions is increasing, and emission reduction strategies are being considered. Liquid fuels from coal would provide some energy security, as they use a domestic resource. CTL fuels might also help maintain lower transportation fuel prices. But, as this analysis shows, increased used of these fuels would not contribute to significant reductions of GHG emissions. In addition, if a life cycle carbon tax is established, the economic advantage of these CTL fuels over petroleum-derived fuels is greatly reduced. Additionally, any effort to increase production with CTL fuels would imply significant increases in coal consumption, leading to more rapidly decreasing reserves.

Liquid fuels from domestic natural gas would produce a very slight reduction in GHG emissions (less than 5% at best), and would even help reduce our dependence on foreign sources of fuel. It is unlikely, however, that domestic natural gas could be used to produce GTL fuels. Supply of domestic natural gas is already limited, so these fuels would have to come from foreign sources, which would maintain our dependence on foreign fuels (and increase emissions if LNG is used). Additionally, it is not clear that these fuels would help maintain lower liquid fuel prices. If the U.S. has the goal to increase its energy security and at the same time significantly reduce its GHG emissions, neither CTL or GTL consumption seem like the path to follow.

Similarly to the comparison of coal and natural gas for electricity generation, the comparison presented in this chapter is U.S.-centric. The FT-plant characteristics, however, are based on ASPEN PLUS models, not on specific plants (no FT-Liquids plants have not been built in the U.S). Therefore FT-plants with these characteristics could be built anywhere in the world. As a result, the primary conclusion from this comparison can be extended to other countries that might be thinking about increasing consumption of CTL and GTL fuels: these fuels do not provide emission reductions compared to petroleum-derived fuel.

4.2 Compressed Natural Gas

I have discussed producing transportation fuels from natural gas via the Fischer-Tropsch reaction. Natural gas can also be used as a transportation fuel by compressing it and using it in a compressed natural gas (CNG) vehicle. In this section, I perform a brief analysis comparing CNG to FT-liquids. This comparison concentrates on life cycle GHG emissions only.

4.2.1 The Life Cycle of Compressed Natural Gas

The life cycle of CNG is very similar to the life cycle of natural gas used for electricity generation; only an extra life cycle stage, compression, must be added before the natural gas is used in the vehicle. This compression is performed at the re-fueling stations after the natural gas is delivered via the natural gas transmission system. The GHG emissions from natural gas production, processing, transmission and combustion developed in Chapters 2.2 and 3 are used. Additional emissions from the compression of the natural gas were developed using the compression energy consumption given in the GREET model (45). Compression can be done either by an electric compressor that would use 10 kWh per MMBtu of natural gas compressed or by a natural gas compressor that would use 90,500 Btu of natural gas per MMBtu of natural gas compressed. These compressor types were used to develop a range of emissions from compression. The emissions from electric compressors are the life cycle GHG emissions of the current electricity mix (including the 9% losses in the transmission of electricity), used in the FT-liquid analysis (between 1,310 and 1,375 pounds of CO₂ equivalents per MWh). Alternatively, the emissions from natural gas powered compressors are the emissions from the combustion of the natural gas used, as well as the upstream emissions of natural gas reported in Chapter 2.2. Using this data, I find that the range of life cycle emission of compressed natural gas derived from either a domestic supply or from imported LNG, as shown in Figure 28. It is important to note that the opportunity of performing carbon capture at a

production plant is not available in the CNG life cycle. Therefore for CNG, like for petroleum-based fuels, there are no worst-case/best-case production scenarios.



Figure 28: Life Cycle GHG Emissions of CNG. The error bars presented in this figure represent the uncertainty/variability associated with the upstream emissions of natural gas. NA-NG: North American Natural Gas. LNG: Liquefied Natural Gas.

4.2.2 Comparing CNG to FT-Liquids and Petroleum-Based Fuels

The life cycle GHG emissions of CNG given in Figure 28 are reported in units of pounds per MMBtu of CNG used. In order to compare these emissions to the life cycle emission of FT-liquids and petroleum-based fuels, the efficiency of the CNG vehicles must be taken into account to produce a life cycle emission factor in units of pounds per mile driven. Currently in the U.S. there are not many CNG vehicles, so EPA has very limited fuel efficiency data. For this analysis the official EPA efficiency of a 2007 CNG Honda Civic was used. This vehicle has a combined (city and highway) efficiency of 32 miles

per gasoline gallon equivalent. A gasoline gallon equivalent is approximately 125,000 Btu; so the efficiency of this vehicle is 3,900 Btu per mile.

In order to perform the CNG/FT-liquid/petroleum-based fuel comparison, the life cycle emissions of FT-liquids and petroleum-based fuels reported in the previous chapter must also be converted into pounds per mile driven using the efficiency of diesel/gasoline-powered vehicles. The 2007 Honda Civic, with an official EPA efficiency of 34 miles per gallon (58), was chosen to represent a conventional gasoline car. In the U.S., the Honda Civic for diesel is not available. Volkswagen diesel vehicles (the only diesel vehicles currently available in the U.S.) have 40% increased efficiency over their gasoline versions (59). For this reason, an efficiency of 47 miles per gallon was used for the diesel vehicle.

Figure 29 and Figure 30 show the resulting life cycle emissions of gasoline, diesel and CNG. The highlighted bars in the graphs show the life cycle emissions from conventional petroleum-based gasoline and diesel. In Figure 29, the life cycle emissions of the FT-liquids are the worst-case scenario emissions described in Chapter 4. This figure shows that CTL fuels have significantly higher emissions than CNG. GTL fuels, have slightly higher life cycle emissions than CNG. Finally CNG produced from domestic resources has lower emissions than petroleum-based gasoline, but higher emissions than petroleum-based diesel. In Figure 30, the life cycle emissions of the FT-liquids are the best-case scenario emissions. Comparing these best-case emissions with the emissions from CNG it can be seen that all fuels have relatively the same life cycle emission factors, with LNG derived fuels, having the highest ones.

Worst Case Gasoline vs. CNG



Life Cycle GHG Emissions (Ib CO2 Equiv/100 160 140 120 100 miles 80 60 40 20 0 Benchmark CTL-Maximum GTL-NANG GTL-LNG Imported GTL Petroleum NA-CNG LNG-CNG CTL Plant Gasoline Based Production

Worst Case Diesel vs. CNG

Figure 29: Comparing Life Cycle Emissions of Worst-Case FT-liquids, Petroleum-based Fuels, and CNG.

The worst-case gasoline/diesel emissions assume no carbon capture and sequestration and current grid electricity. The error bars presented in this figure only represent the uncertainty/variability associated with the upstream GHG emissions of coal and natural gas. CTL: Coal-to-Liquids. GTL: Gas-to-Liquids. NANG: North American Natural Gas. LNG: Liquefied Natural Gas. NA-CNG: North American Based Compressed Natural Gas. LNG-CNG: Liquefied Natural Gas Based Compressed Natural Gas

Best Case Gasoline vs. CNG





Figure 30: Comparing Life Cycle Emissions of Best-Case FT-liquids, Petroleum-based Fuels, and CNG.

The best-case gasoline/diesel emissions assume 90% carbon capture and sequestration and the use of a zero-carbon source of electricity. The error bars presented in this figure only represent the uncertainty/variability associated with the upstream GHG emissions of coal and natural gas. CTL: Coal-to-Liquids. GTL: Gas-to-Liquids. NANG: North American Natural Gas. LNG: Liquefied Natural Gas. NA-CNG: North American Based Compressed Natural Gas. LNG-CNG: Liquefied Natural Gas Based Compressed Natural Gas

4.2.3 Discussion of Results

As previously mentioned, when comparing CNG produced with domestic natural gas with the best-case production scenario for FT-fuels produced with domestic resources, the life cycle emissions would be approximately the same. The investments to develop a CNG infrastructure were not analyzed, although they would probably be lower than the investments required for FT-Liquid production, since no centralized production plants would be required. It could be argued, that a new fleet of vehicles would need to be produced, but the same could be argued if we wanted to use GTL for personal transportation. Since GTL plants are better suited for diesel production, the passenger fleet vehicle would have to be replaced with diesel-powered vehicles.

The U.S., however, already has a limited amount of natural gas and it is unlikely that any transportation fuels would be produced with domestic resources. If the U.S. was committed to increasing the production of natural gas-based transportation fuels, LNG would be needed, and if LNG is used no significant reductions in emissions or dependence on foreign sources of fuels would be observed.

5 COMPARING ELECTRICITY GENERATION AND THE PRODUCTION OF TRANSPORTATION FUELS

The previous chapters compared the use of natural gas and coal for a specific use (electricity generation or liquid fuel production). Such comparisons can help us understand which of these two fuels is better suited for each use. It does not tell us, however, which is a better use of the fuel. In other words, the comparisons presented do not tell us if it is better to use coal for electricity or coal for the production of transportation fuels. Such a comparison is not easy. Although in both cases coal is used for energy production, a Btu of electricity is used very differently than a Btu of gasoline. In this chapter, a comparison of coal/NG uses is presented. Here I concentrate on comparing GHG emissions produced in each use. These emissions have been normalized to the energy content of the fuel used; so they are presented in terms of pounds of CO_2 equivalents per million Btu of fuel used. Other parameters that could be included in a comparison of end use are: What is the resource depletion potential of each use? Are there viable alternative fuels that can meet the energy demands of the sector?

5.1 Comparing Coal for Electricity Generation and for the Production of Transportation Fuels

Figure 31 shows the life cycle GHG emissions of coal used for the production of diesel, gasoline and electricity. It can be seen that if CCS were not available, using coal for any of these purposes would basically generate the same life cycle GHG emissions. This is because a Btu of coal will always have the same carbon content, regardless of the use. The same is not true in the case where CCS is available. When using coal for electricity, CCS performed at the plant can capture roughly 90% of the carbon in the coal. When producing transportation fuels, however, even if 90% CCS is available at the FT-plant, most of the carbon in the coal is transferred to the liquid fuels, which are then combusted



(without CCS) in regular vehicles. Thus, the effective CCS rate when producing liquid fuels is approximately 50%

Figure 31: Life Cycle GHG Emissions of Coal Consumption. The error bars presented in this figure represent the uncertainty/variability associated with the upstream GHG emissions of coal.

5.2 Comparing Natural Gas for Electricity Generation and the Production of Transportation Fuels

Similarly to the comparison of coal for electricity generation and coal for the production of transportation fuels, Figure 32, shows the comparison of uses of domestic natural gas. In this graph the use of Qatari or Malaysian natural gas for the production of liquid fuels that are then imported to the U.S. are also included. CNG is included for completeness. Because in the CNG life cycle there is no opportunity for CCS, no bar is shown for a CCS scenario. Notice than CNG has slightly higher life cycle GHG emissions than FT-liquids and than electricity. Even though the carbon content of natural gas is constant regardless of how it is used, the use of electricity in the CNG life cycle adds some carbon

to the life cycle of this natural gas. If CCS is available, it is better to use the natural gas to produce electricity.



Figure 32: Life Cycle GHG Emissions of "Domestic" Natural Gas Consumption. The error bars presented in this figure represent the uncertainty/variability associated with the upstream GHG emissions natural gas. NA-NG: North American Natural Gas. GTL: Gas-to-Liquids. CNG: Compressed Natural Gas

Figure 33 shows the comparison of consumption of imported natural gas. In this figure, imported GTL fuels are also included. Notice that if no CCS is available, it is better to produce liquid fuels than to produce electricity when using LNG. This was also observed, to a smaller extent, in the comparisons of domestic natural gas consumption (Figure 32). The slight advantage of GTL fuels over electricity is because GTL plants without CCS also generate electricity, and the emissions shown below only represent the emissions allocated to the production of the diesel and the gasoline. If CCS is available, however, it is better to use these imported resources to produce electricity, where the capture rate is 90% (compared to the effective CCS rate of GTL fuels of approximately 25%).

The most significant result from the graph is that when no CCS is available, importing refined GTL fuels has the lower life cycle GHG emissions of all the consumption

alternatives. This is significant because Qatar has significant stranded natural gas resources. Thus, the better way (in terms of GHG emissions) for Qatar to export these resources to the U.S. market in the next 20 years (a period during which CCS will probably not be available) is to produce GTL fuels rather than shipping LNG. This decision however, must be weighted against the potential to be locked in a path that does not give the best life cycle GHG emissions once CCS becomes available.



Figure 33: Life Cycle GHG Emissions of Imported Natural Gas Consumption. The error bars presented in this figure represent the uncertainty/variability associated with the upstream GHG emissions natural gas. LNG: Liquefied Natural Gas. GTL: Gas-to-Liquids. CNG: Compressed Natural Gas

6 CONTRIBUTION, GENERAL CONCLUSIONS AND FUTURE WORK

6.1 Research Questions and Contribution Revisited

This research was divided in four stages as described in Chapter 1. This work seeks to answer three key questions about coal and natural gas consumption: Is it better to use coal or natural gas for electricity generation? Is it better to use coal or natural gas for the production of transportation fuels? And finally what is a better use of each fuel? Answering these questions can help the U.S. prioritize efforts in the development of such resources.

The analysis shows that with current technology it is better to use natural gas (even if it is imported LNG) than coal to generate electricity. In a future of advanced power plant technologies and CCS, however, coal will likely be better suited for electricity generation than LNG.

When comparing the use of coal and natural gas for the production of transportation fuels, it was found that GTL fuels have lower life cycle GHG emissions than coal, if CCS is not available. If CCS is available, however, CTL and GTL fuels basically have the same life cycle GHG emissions, and GTL fuels derived from natural gas imported in the form of LNG are worse than CTL fuels. In addition, it was found that replacing petroleum-derived fuels with CTL or GTL fuels would not result in a reduction of GHG emissions associated with transportation fuels. A different story emerges when considering costs of production. Based on current energy prices, CTL fuels have better economic performance than GTL fuels. The result is very uncertain, however, as there is large variability and volatility associated with future energy prices. Therefore, this analysis shows that it is difficult to answer the second question put forth: Is it better to

use coal or natural gas for the production of transportation fuels? It was found, however, is that neither CTL nor GTL fuels are good replacements for petroleum-derived transportation fuels.

Answering the third question, what is a better use of each fuel, was more challenging than expected. This analysis is limited to a comparison of life cycle GHG emissions associated with each use and it was found that it is better to use coal to produce electricity than to produce transportation fuels. For North American natural gas, it can be said that it is also better to use it for electricity generation than for the production of transportation fuels. Interestingly, the answer is not the same when looking at stranded natural gas from foreign countries like Qatar. It is currently better to use that natural gas to produce GTL fuels that can then be imported by the U.S., than to produce LNG that would then be used for electricity generation in the U.S. In a future that contains CCS, however, it will be better to import the LNG for electricity generation.

Although, these results help answer key questions, new questions and challenges regarding the future use of resources were identified, as will be discussed in the next section.

6.2 Conclusion and Discussion

A discussion of the specific results obtained in each separate analysis was presented in each of the previous chapters, and summarized in the previous section. In this section, I present some general conclusions and thoughts that result from the entire thesis effort.

One of the most important results of this thesis is that life cycles matter. The research of Bergerson (32), Marriott (60), and other colleagues has also shown this. It is still important to repeat this conclusion: Life cycles matter. When comparing coal and natural gas for electricity generation, if we only look at the GHG emissions from the power plant, natural gas looks like a much better fuel choice, regardless of the source of this

natural gas. Looking at the life cycle however, has allowed us to see that these benefits at the combustion plant are reduced by the emissions from other stages of the life cycle. Looking at the life cycle also allowed us to identify that in a future where emissions from the power plant are reduced, the benefits of natural gas over coal are not very significant, especially if the natural gas has to be imported in the form of LNG. Similarly when comparing CTL fuels, GTL fuels and petroleum-derived fuels, if we concentrated on combustion emissions, we would not realize that CTL fuels and GTL fuels could actually increase the GHG emissions associated with transportation fuels. If we looked only at combustion emissions, we might erroneously conclude that the emissions from CTL fuels, GTL fuels and petroleum-derived fuels would be approximately the same. So once again, an important conclusion of this research is that life cycles matter!

Since life cycles matter, it is important that utility companies and oil companies be encouraged to make decisions based on the life cycle of the fuels. Policy tools, such as a carbon tax based on the life cycle GHG emissions of these fuels, would encourage consumers of coal and natural gas to make life cycle based decisions and should be identified.

Decisions about our energy future cannot be made in a vacuum. In this thesis, I find that in the years before CCS is available to reduce emissions from power generation plants, electricity produced with globally sourced natural gas could help the U.S. reduce the life cycle emissions associated with electricity generation. CCS will probably not be available in the next 15 to 20 years, which means that switching from coal to natural gas (even if it is LNG) now, could give us 20 years of GHG emission reductions. To do this, however, we would need to build the entire infrastructure to allow us to import LNG, and this would require significant investments. In 20 years, when CCS becomes available, and the life cycle GHG emission of electricity from LNG could be worse that the life cycle emissions from coal electricity, what are we going to do with all the infrastructure we would have built? Are we going to keep importing LNG to generate electricity just because we have made all the investments in the infrastructure? How do we balance shorter-term benefits with longer-term costs? I think that part of this balancing act is to

look at other alternatives that would allow us to have GHG emission reductions in the next 20 years, without locking ourselves in a future of higher long-term costs. For example, as I said, CCS is not expected to become widely available before at least 15 years. The reasons for this delay in implementation are more economical and political than technical. Based on the technical status, CCS is ready for implementation. Therefore, the question is not whether we should make major investments in LNG infrastructure that could help us decrease emissions for the next 20 years while we wait for CCS, but should we have policy measures that encourage investment in CCS implementation as soon as possible? Other policies should be established to encourage improvements in efficiency in our current energy system and to decrease demand for electricity, among others.

Similarly, I find that the use of CTL fuels is not a GHG emission reduction strategy. They could however, allow us to reduce our dependence on foreign sources of fuels. They could also help us maintain lower transportation fuel prices. There is, however, a lot of uncertainty associated with the energy security benefits and cost benefits of CTL fuels. It has recently been reported that although there are probably enough coal resources to meet our demand (at current consumption levels) for the next century, it is not possible to determine the validity of the generally quoted statement that says we have 250 years of coal at current rates. If consumption rates increase, the uncertainty associated with how many years of coal are available grows. Additionally, it is unclear that coal prices will remain low with increased consumption and uncertain reserves. If coal prices increase, the economic advantages of CTL fuels over petroleum-derived fuels decrease. A carbon tax derived from the life cycle GHG emissions associated with transportation fuels, could also diminish the economic advantages of CTL fuels. How do we make a decision about these fuels given this uncertainty? Once again, it is important to realize that this decision should not be made in a vacuum. The goal of energy security is an important one, but CTL fuels may not be the only path that leads to energy security. We need to investigate if there are other paths to energy security that should be pursued before going down the coal-to-liquid path. And most importantly, how can we promote the development of those other alternatives now?

This analysis tells us that GTL fuels do not give us emission reductions compared to petroleum-derived fuels, and they do not provide significant economic benefits. They also do not contribute to energy security, since these fuels would likely come from foreign sources of natural gas. There are places in the world, however, that have enormous amount of natural gas, but not enough demand. Qatar is one of these countries, and they are looking at ways to exploit these resources. They could do this by developing the infrastructure to export LNG, or they could produce GTL fuels for export. It is found that in terms of GHG emissions, in a near future that does not have CCS, it would be better that they export the GTL fuels rather than the LNG. Exporting these fuels would increase the life cycle GHG emissions associated with the consumption of transportation fuels, and would not help decrease our dependence on foreign fuels. How do we stop these countries from developing projects that might not make much environmental sense? We have heard that Exxon-Mobil decided not to invest in GTL fuels in Qatar because they did not make economic sense. We might find that this will lead to investments in LNG infrastructure that may make more economic sense but have worse environmental implications. What is the role of U.S policy makers when dealing with issues like these? Maybe by looking at our own energy future in a holistic way, not just as an issue of whether we use one fuel or the other, we can influence the market and the way other countries make decisions about their own investments in energy infrastructure.

6.3 Future Work

The basis of all the analysis presented in this thesis is the development of emission factors for the upstream stages of the life cycles of coal and natural gas. Publicly available information was used to develop these numbers, and I feel the results obtained are quite robust. In the future, however, more data can become available. The U.S. EPA, for example, has started working on updating the study on methane emissions from the U.S. natural gas system. Some corporations have also shown interest in providing us data for future LNG liquefaction and re-gasification technologies. Similarly, more detailed

data on the performance characteristics of SNG plants may become available in the future. Future work would involve incorporating all these new data into the analysis.

Throughout the thesis I mentioned that if the U.S. seeks to increase its consumption of natural gas it would have to depend on imports of LNG. For this to happen, the LNG infrastructure would need to be developed. Expanding my work to characterize the infrastructure that would be required and the investments associated with this infrastructure could be useful.

In the analysis for GTL and CTL fuels co-product energy and emission allocation had to be performed. This allocation was performed using refinery-level data. It was mentioned that a better method is to perform allocation at each refining stage. The data to do this was unavailable, but in the future, an analysis of the effects such an allocation method has on the results could be performed as data becomes available.

An initial goal of this thesis was to determine the best use of each fuel (coal and natural gas). In the brief analysis performed, I looked at which use would have the lowest life cycle GHG emissions. This single attribute comparison is definitely insufficient to answer the question. In the future, it will be important to think about a better method to compare different uses. A complication that was found in trying to answer this question is how to deal with comparing two products that are used in completely different ways. For this thesis, GHG emissions are very important, so I concentrated on looking at the emissions produced for using one unit of each fuel to produce the different products. Someone else might think the efficiency of producing the two products should be compared. If this were done, they would find that it is more energy efficient to produce CTL fuels (efficiency above 50%) than to generate electricity with coal (efficiency of 40%, at best). But if we used our coal to produce CTL, how would we generate electricity? Are there enough alternative resources to meet our electricity demand? If we are truly committed to figuring out what is the best use of a resource, we will need to think about incorporating all these questions into the analysis.

It is important that the comparative framework developed here be expanded to include other energy resources. For example, coal and natural gas for transportation are compared here. How do these fuels compare with increased fuel efficiency in the current vehicle fleet, and to plug-in hybrids, and to bio-fuels? Expanding this research to include these other options can be a significant step towards prioritizing efforts that will lead to a more sustainable energy future.

Finally, it is important to identify policy tools that can be used to promote a more sustainable energy future. A carbon tax based on the life cycle GHG emissions associated with the use of each fuel can help lead utilities and industries to consider the life cycle impacts of their consumption. It could also promote the implementation of carbon capture and sequestration. Questions need to be answered about this tax. For example, how should this tax be managed and how would taxes on imported fuels be designed? Besides a carbon tax, what other policy tools are available? How would CTL and GTL fuels be affected by regulations to increase fuel efficiency of vehicles? What kind of other financial tools should be used to discourage CTL and GTL projects and encourage CCS?

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APPENDIX A: SENSITIVITY ANALYSIS OF FT-LIQUIDS ECONOMICS

As mentioned in Section 4.1.2, the economics of CTL and GTL fuels will vary depending on the price of natural gas, the price of coal, the price of oil, and the carbon tax. The figures presented in this appendix show the results of a sensitivity analysis performed. Each graph was developed for a given carbon tax. The y-axis shows the difference between the price of the petroleum-derived fuels and the CTL/GTL fuel. The x-axis shows the varying prices of coal/natural gas. Finally the contour lines represent a given crude oil price.

No Carbon Tax



Figure A 1: Worst-Case CTL Life Cycle Emissions, No Carbon Tax



Figure A 2: Best-Case CTL Life Cycle Emissions, No Carbon Tax



Figure A 3: Worst-Case GTL Life Cycle Emissions, No Carbon Tax



Figure A 4: Best-Case GTL Life Cycle Emissions, No Carbon Tax

Carbon Tax of \$20/ton CO₂



Figure A 5: Worst-Case CTL Life Cycle Emissions, \$20/ton CO₂



Figure A 6: Best-Case CTL Life Cycle Emissions, \$20/ton CO₂



Figure A 7: Worst-Case Domestic GTL Life Cycle Emissions, \$20/ton CO₂



Figure A 8: Best-Case Domestic CTL Life Cycle Emissions, \$20/ton CO₂



Figure A 9: Worst-Case LNG-GTL Life Cycle Emissions, \$20/ton CO₂



Figure A 10: Best-Case LNG-GTL Life Cycle Emissions, \$20/ton CO₂

Carbon Tax of \$60/ton CO₂



Figure A 11: Worst-Case CTL Life Cycle Emissions, \$60/ton CO₂



Figure A 12: Best-Case CTL Life Cycle Emissions, \$60/ton CO₂



Figure A 13: Worst-Case Domestic GTL Life Cycle Emissions, \$60/ton CO₂



Figure A 14: Best-Case Domestic GTL Life Cycle Emissions, \$60/ton CO₂



Figure A 15: Worst-Case LNG-GTL Life Cycle Emissions, \$60/ton CO₂



Figure A 16: Best-Case LNG-GTL Life Cycle Emissions, \$60/ton CO₂

Carbon Tax of \$100/ton CO₂



Figure A 17: Worst-Case CTL Life Cycle Emissions, \$100/ton CO₂



Figure A 18: Best-Case CTL Life Cycle Emissions, \$100/ton CO₂



Figure A 19: Worst-Case Domestic GTL Life Cycle Emissions, \$100/ton CO₂



Figure A 20: Best-Case Domestic GTL Life Cycle Emissions, \$100/ton CO₂



Figure A 21: Worst-Case LNG-GTL Life Cycle Emissions, \$100/ton CO₂



Figure A 22: Best-Case LNG-GTL Life Cycle Emissions, \$100/ton CO₂

Carbon Tax of \$140/ton CO₂



Figure A 23: Worst-Case CTL Life Cycle Emissions, \$140/ton CO₂


Figure A 24: Best-Case CTL Life Cycle Emissions, \$140/ton CO₂



Figure A 25: Worst-Case Domestic GTL Life Cycle Emissions, \$140/ton CO₂



Figure A 26: Best-Case Domestic GTL Life Cycle Emissions, \$140/ton CO₂



Figure A 27: Worst-Case LNG-GTL Life Cycle Emissions, \$140/ton CO₂



Figure A 28: Best-Case LNG-GTL Life Cycle Emissions, \$140/ton CO₂