# Comparative Analysis of the Production Costs and Life-Cycle GHG Emissions of FT Liquid Fuels from Coal and Natural Gas

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Liquid transportation fuels derived from coal and natural gas could help the United States reduce its dependence on petroleum. The fuels could be produced domestically or imported from fossil fuel-rich countries. The goal of this paper is to determine the life-cycle GHG emissions of coal- and natural gas-based Fischer–Tropsch (FT) liquids, as well as to compare production costs. The results show that the use of coal- or natural gas-based FT liquids will likely lead to significant increases in greenhouse gas (GHG) emissions compared to petroleum-based fuels. In a best-case scenario, coal- or natural gas-based FT-liquids have emissions only comparable to petroleum-based fuels. In addition, the economic advantages of gas-to-liquid (GTL) fuels are not obvious: there is a narrow range of petroleum and natural gas prices at which GTL fuels would be competitive with petroleum-based fuels. CTL fuels are generally cheaper than petroleum-based fuels. However, recent reports suggest there is uncertainty about the availability of economically viable coal resources in the United States. If the U.S. has a goal of increasing its energy security, and at the same time significantly reducing its GHG emissions, neither CTL nor GTL consumption seem a reasonable path to follow.

## 1. Introduction

By 2030, petroleum demand in the United States is projected to be 27 million barrels per day, 73% of which will be used by the transportation sector. Over 70% of petroleum and petroleum-related products will be imported from oil-rich countries, some of which have volatile political and social situations (*1*). In addition to dependency, petroleum combustion from the transportation sector is and will remain one of the largest sources of $CO_2$ emissions in the country. EPA estimates that in 2006, 26% of the total U.S. $CO_2$ emissions came from the transportation sector (*2*).

As a response to concerns over petroleum consumption, interest in alternative transportation fuel has risen. One alternative is fuels produced from coal or natural gas via the Fischer–Tropsch (FT) process (*3*). The U.S. is rich in coal and the technology to produce coal-to-liquid (CTL) fuels already exists and has been in widespread use in South Africa since the 1980s (*3*). Natural gas is limited in the U.S., which in 2007 imported 3.8 billion cubic feet from Canada and Mexico, and with ever increasing imports of LNG (LNG imports increased from 5.8 to 7.7 billion cubic feet between 2006 and 2007) (*4*). Domestic natural gas production is predicted to be flat or decreasing in coming decades. Natural gas, however, is less carbon intensive than coal, and gas-to-liquid fuels (GTL), especially if foreign sourced, could be another alternative. GTL fuels are currently produced in Qatar and Malaysia (*3, 5*).

CTL fuels, and to a lesser extent GTL fuels, would reduce the U.S. dependence on foreign sourced petroleum by directly substituting for gasoline or diesel (*3*). It is not clear, however, what impacts production and consumption of these fuels would have on greenhouse gas (GHG) emissions. In this paper we perform a life-cycle analysis of GHG emissions from coal- and natural gas-derived liquid fuels in order to help answer this question. In addition a brief economic analysis will be presented. A comparison with petroleum-based fuels is included, in order to have a better understanding of the advantages or disadvantages of using coal and natural gas as a feedstock for transportation fuels.

## 2. Life-Cycle of FT Liquid Fuels

There are several pathways for the production of FT fuels for U.S. consumption, and so there are different life-cycles stages to consider in this analysis. The life-cycle of FT fuels produced from coal starts with coal mining and processing. Coal is then transported to the CTL plant, where it is gasified to produce syngas (CO and $H_2$). Syngas is converted by the FT process to a synthetic crude, which is then further refined into liquid fuels such as diesel and gasoline. The efficiency of the process, and types and amount of fuels produced, can be influenced by catalyst choice (*6*). 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 steam methane reforming and noncatalytic partial oxidation. As in the CTL plant, the syngas is then converted into a synthetic crude that is further refined into gasoline and diesel. 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, but with the need to transport the refined diesel and gasoline to the U.S. This study 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 S1 in the Supporting Information graphically shows the life-cycle stages of FT fuels.

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**TABLE 1. Process Inputs and Outputs of CTL and GTL plants (*6, 8*)**

| | CTL plant | | |
|---|---|---|---|
| | base-case design | maximum gasoline production | GTL plant |
| **inputs** | | | |
| coal (metric tons/day) | 16,875 | 16,875 | 0 |
| natural gas (million $m^3$/hr) | 0 | 0 | 0.6 |
| methanol (metric tons/day) | 0 | 190 | 0 |
| butanes (metric tons/day) | 290 | 400 | 32 |
| purchased electricity (no CCS) (MWh/day) | 1,300 | 1,350 | −590 |
| purchased electricity (90% CCS) (MWh/day) min | 3,180 | 3,230 | −155 |
| max | 4,590 | 4,630 | 170 |
| **outputs** | | | |
| propylene (TJ/day) | 0 | 11.7 | 0 |
| propane (LPG) (TJ/day) | 7 | 5.8 | 6.2 |
| gasoline (TJ/day) | 109 | 177 | 77 |
| diesel (TJ/day) | 133 | 49 | 137 |
| carbon lost (metric tons/day) | 7,094 | 7,076 | 1,651 |

For more information on the life cycle of coal and natural gas, see Jaramillo et al. (*7*).

## 3. Methods for Calculating Life-Cycle GHG Emissions

This analysis includes five pathways for FT liquid production and supply: two coal-to-liquid (CTL) pathways and three gas-to-liquid (GTL) pathways. We consider as a base case a CTL plant that produces 53% diesel, 44% gasoline, and 3% propane (*6, 8*). A second CTL plant design maximizes gasoline production. The product mix is changed to 20% diesel, 73% gasoline, and 7% propylene and propane (*6, 8*).

A conventional GTL plant produces 62% diesel, 35% gasoline, and 3% propane (*6, 8*). These plants can be fueled with domestic natural gas or with imported LNG. In the third GTL pathway considered, the conventional GTL plant is built in Qatar or Malaysia, and the U.S imports the refined fuels.

The boundary of this life-cycle analysis includes GHG emissions from the production, processing, and transport of the feedstock fuels. It also includes the emissions at the FT plant (which includes the refining of the synthetic crude produced in the FT reactor into liquid fuels), the life-cycle emissions from the electricity used in the plant, emissions from transporting the refined products, and the liquid fuel combustion emissions. It does not include emissions from the construction of any infrastructure.

Emissions from the production, processing, and transport of coal, domestic natural gas, and LNG were obtained from Jaramillo et al. (*7*). Values used for emissions from mining, processing, and transporting coal range between 3.5 and 7.0 g of $CO_2$ equivalents per megajoule (g $CO_2$e/MJ). For domestic natural gas, the upstream use emissions range between 6.5 and 8.6 g $CO_2$e/MJ. For LNG these emissions range between 13 and 31 g $CO_2$e/MJ (*7*). 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, as suggested by Jaramillo et al. (*7*). All these feedstock emission factors are converted to g $CO_2$e/MJ of FT-liquid by using the efficiencies of FT plants (*6, 8*).

Table 1 shows the process inputs and outputs from these CTL and GTL plants. The data were used to estimate plant GHG emissions by calculating the energy and carbon dioxide balances. The base-case CTL plant produces slightly more diesel than gasoline with an overall energy efficiency of 54% high heating value (HHV). This base-case CTL plant can be modified to produce more gasoline, slightly lowering the overall energy efficiency to 52% HHV. Note that this analysis uses Illinois number 6 coal as the feedstock for the CTL plants (*6, 8*). In a GTL plant more diesel than gasoline is produced, and the plant has an overall efficiency of 55% HHV (*6, 8*).

$CO_2$ is generated in these plants in the syngas production stage. Since $CO_2$ will interfere with the FT reaction, all FT plant designs 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 carbon capture and sequestration (CCS) capable.

CTL plants without CCS purchase electricity from the grid, while GTL plants generate enough electricity for their own use and sell some excess power (*6, 8*). Installing $CO_2$ compression to achieve 90% CCS would demand additional power: between 80 and 140 MWh per metric ton of $CO_2$ compressed (*9, 10*). Table 1 shows electricity purchases for the different plants for two cases: with and without CCS. Note that in the case where there is CCS, a range of power requirements is used since there is uncertainty in the amount of power needed to compress the $CO_2$, as previously noted.

In addition to the direct power requirements of the plant, 9% losses from the transmission of this power (*11*) 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. The electricity life cycle includes the emissions from the upstream stages of the life cycle of the fuels used and the emissions from the combustion at currently operating power plants. Currently, approximately 50% of U.S electricity is generated with coal, 20% with natural gas, and the rest with low-carbon sources (*12*). Using this electricity generation mix and the emission data given by Jaramillo et al. (*7*), the electricity life-cycle emission factor is between 600 and 620 kg $CO_2$e/MWh. This range is used to find the high-emissions scenario from CTL and GTL production. In the low-emission scenario, it is assumed that the power purchased by CTL and GTL plants is generated using low-carbon sources, such as nuclear or carbon free renewables. As a bounding low-emission scenario, we model these electricity sources as zero-carbon, even though there really is not an absolute zero-carbon electricity source.

In a GTL plant without CCS, surplus power can be sold. In this case the plant could 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.

**TABLE 2. Liquid Fuel Transportation Assumptions (*13, 14*)**

| mode | trip description | energy intensity (kJ/metric ton-km) GREET | trans. energy book | distance traveled (km) | fuels used | % fuels transported weight | metric ton-km |
|---|---|---|---|---|---|---|---|
| barges | full load | 291 | 301 | 837 | 100% residual oil | 33% | 61% |
| | back haul | 222 | | | | | |
| pipeline | one way | 183 | 185 | 645 | 20% diesel, 50% residual oil, 30% natural gas | 60% | 29% |
| rail | one way | 267 | 249 | 1,287 | 100% diesel | 7% | 4% |
| truck | both ways | 743 | 393 | 48 | 100% diesel | 100% | 6% |

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, allocation of emissions must be performed. A discussion about allocation issues can be found in the Supporting Information. For the rest of the analysis allocation based on energy content of the products is used.

Emissions from liquid fuel transport and liquid fuel combustion must be added to the allocated well-to-plant emissions in order to obtain the "well-to-wheel" emissions. Liquid fuels in the U.S. are transported via barges, pipeline, rail, and truck. Table 2 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 (*13*)) or by metric ton-km 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 2 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.

In the case where CTL fuels are produced in other countries and imported by the U.S., tanker transport is included. Qatar and Malaysia are the two countries that are investing in a GTL production infrastructure (*3*), so it was assumed that GTL liquids would be imported from these countries. The GREET model assumes the energy intensity of petroleum product tankers to be 23.3 kJ/metric ton-km, with residual fuel providing this energy (*13*). Alternatively, the method for calculating ship transport emissions presented by Trozzi et al. (*15*) is used to produce a range of tanker emissions. Using this method a tanker with a bulk weight of 90,720 t traveling at 14 knots has an energy intensity of 15.6 kJ/metric ton-km (*15*). Residual fuel was also assumed to provide this energy.

Gasoline and diesel produced from coal and natural gas have a carbon content of 19 and 18 g of carbon per megajoule, respectively, and an energy content of 31 and 36 megajoule per liter, respectively (*8*). These data were used to determine the GHG emissions from combusting these fuels.

## 4. Results of Life-Cycle GHG Analysis

Figure 1 shows the high-emissions scenario well-to-wheel GHG emission factors for gasoline. The error bars presented in these figures represent the uncertainty/variability in the upstream emission factors of coal, natural gas, and electricity reported by Jaramillo et al. (*7*), as well as variability in the emissions from liquid fuel transport. The high-emissions scenario uses the current U.S. fuel mix for electricity generation (50% coal, 20% natural gas, and 30% low-carbon sources (*12*)) and does not consider CCS for the FT plants. The figure shows the emissions for petroleum gasoline adapted from the GREET model (*13*) as a comparison to the GTL and CTL gasoline. A similar value was found for diesel and is shown in Figure S4 in the Supporting Information.

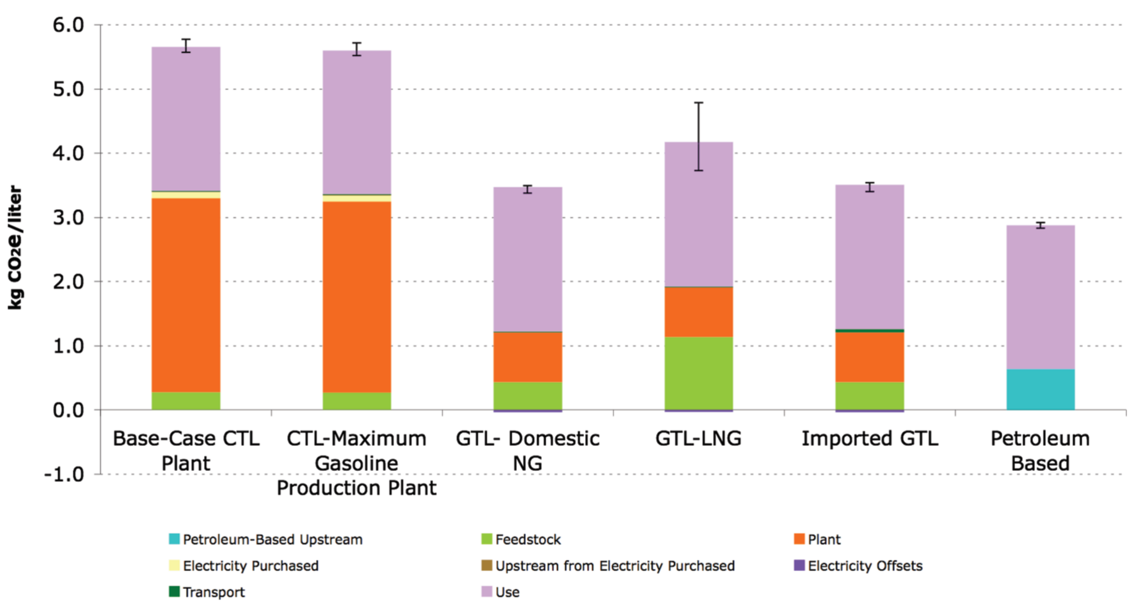


**FIGURE 1. Comparison of well-to-wheel GHG emissions for gasoline produced from coal and natural gas (high-emissions scenario).**

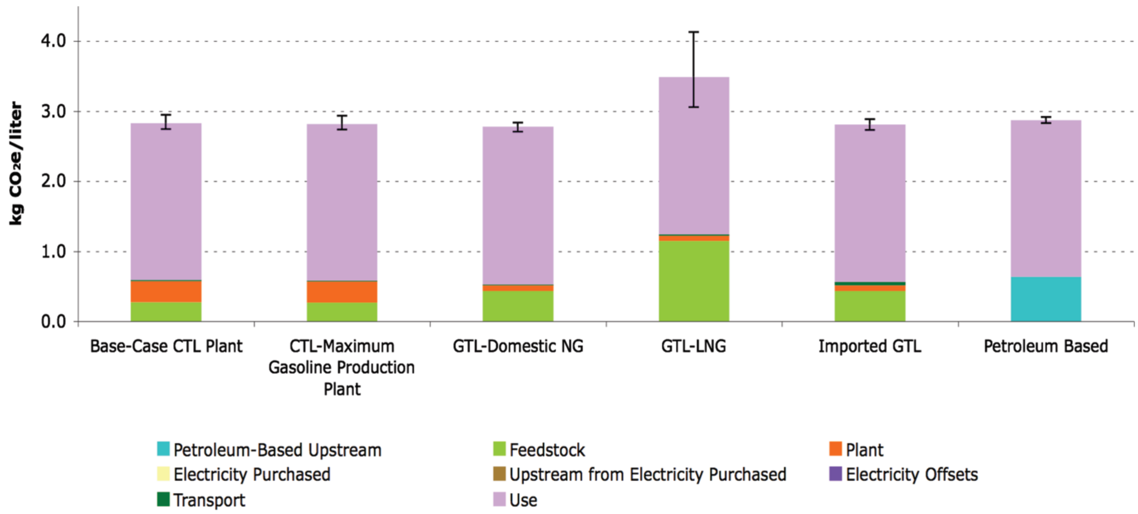


**FIGURE 2. Comparison of well-to-wheel GHG emissions for gasoline produced from coal and natural gas (low-emissions scenario).**

As can be seen in Figure 1 and Figure S4 in the Supporting Information, gasoline and diesel produced from coal could emit about double the GHG emissions of petroleum-based gasoline and diesel. If domestic natural gas were used to produce gasoline, or if natural gas-based gasoline were imported from Qatar or Malaysia, an increase in emissions of 20−25% would be seen. If LNG is used, an increase of around 50% in emission factors for both gasoline and diesel could be observed.

Figure 2 shows the low-emissions scenario well-to-wheel GHG emission factors for gasoline produced with coal and natural gas. Figure S5, in the Supporting Information, shows a comparable figure for diesel. Here all FT plants use CCS and a low-carbon source of electricity. These assumptions are used to show a potential lower bound for GHG emissions. As in the figures for the high-emissions scenario, the error bars represent the uncertainty/variability in the upstream emission factors of coal natural gas, and electricity reported by Jaramillo et al. (*7*), as well as variability in the emissions from liquid fuel transport.

As can be seen in the figure, all cases, except when LNG is used as a feedstock, show slight reductions (less than 4%) in emissions to the life-cycle of petroleum gasoline. In the case of diesel, the use of coal or domestic natural gas could result in a slight increase of less than 5% 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.

The FT technology is constantly evolving and it could be expected to attain greater conversion efficiencies with time, particularly for coal, which is less developed. Thus, the efficiency required for CTL and GTL fuels to achieve the same life cycle GHG emissions as petroleum-based fuels (breakeven) was calculated, as described in the Supporting Information. This calculation shows that if a CTL plant (without CCS and powered with current electricity) converts 100% of the energy in the coal into liquid fuels, the life-cycle GHG emissions of these fuels would still be higher than the life-cycle GHG emissions of petroleum-based fuels. With CCS removing 90% of the process-generated $CO_2$ and low carbon sources providing the plant's electricity, in a CTL the breakeven conversion efficiency is 55%. GTL plants (without CCS and powered with current electricity) that use domestic resources and have a conversion efficiency of 70% would achieve breakeven. With CCS and low-carbon sources of electricity, the efficiency for breakeven drops to 55%.

## 5. The Economics of FT Liquid Fuels

In the previous section we show that CTL and GTL are not a GHG emission reduction strategy: at an extremely optimistic scenario, these fuels have life-cycle GHG emissions similar to those of petroleum-based fuels, and LNG-derived fuels would increase emissions. Energy prices and energy security are, however, two other factors leading the U.S. to consider these alternative transportation fuels. No GTL or CTL fuel plants have been built in the United States and the international experience with these plants has been limited to few countries. Actual cost data for operating plants is not widely available; only rough estimates and ranges are available. Table 3 shows levelized cost estimates for these plants, and the assumptions used to develop these costs. The price for coal used was the spot price for Illinois number 6 coal in March 2008 (*16*). The price for natural gas used was the average price paid by industrial consumers in March 2008 (*17*). Fixed operation and maintenance (O&M) costs for the plants were obtained assuming they are 4% of the capital costs and adding an electricity cost based on the electricity consumed by the plants (as presented in Table 1) and a purchase price of electricity of $0.06/kWh (*18*). In the CTL plant the additional use of electricity in the CCS plant (CCS plants consume 35−65 additional KWh per barrel of liquid fuel) increased the O&M by 50%. In the GTL plant no significant change is observed in the O&M cost because even though the plant may need to start purchasing electricity (about 5 kWh per barrel of liquid fuel) instead of producing enough on site, this purchase is not significant (less than $0.5 per barrel). Increased electricity cost would increase the O&M costs, but the change would not be 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 value is used by Rubin et al. to calculate the levelized cost of electricity from IGCC plants and NGCC plants (*19*).

The levelized costs are not useful by themselves. They only have meaning when comparing CTL and GTL fuel costs with the cost of the fuels they are meant to replace−petroleum-based gasoline and diesel. GTL and CTL plants produce different liquid fuels that could be sold at different prices. To develop a separate cost for producing diesel and gasoline at these plants, specific mass and energy balance data for each refining stage would be needed in order to allocate feedstock and energy use to each fuel produced. As discussed in the Supporting Information, this level of detail is not available, so we only developed an average cost per gallon of liquid fuel produced. To compare this average number to

**TABLE 3. Levelized Cost of CTL and GTL Plants**

| | | | current U.S. natural gas prices | | low natural gas prices | |
|---|---|---|---|---|---|---|
| | CTL plant (no CCS) | CTL plant (w/CCS) | GTL plant (no CCS) | GTL plant (w/ CCS) | GTL plant (no CCS) | GTL plant (w/ CCS) |
| plant capacity factor | 85% | 85% | 85% | 85% | 85% | 85% |
| plant cost ($1,000/daily bbl) (*20–23*) | 70 | 90 | 20 | 30 | 20 | 30 |
| fixed O&M cost ($/bbl) | 10 | 15 | 5 | 5 | 5 | 5 |
| price of feedstock fuel ($/ton coal or $/MCF of NG) (*16, 17*) | 52 | 52 | 8.94 | 8.94 | 0.5 | 0.5 |
| price of feedstock fuel ($/metric ton coal or $/1,000 m$^3$ of NG) (*16, 17*) | 57 | 57 | 316 | 316 | 18 | 18 |
| feedstock fuel cost ($/bbl) | 19 | 19 | 82 | 82 | 4.6 | 4.6 |
| capital charge factor | 15% | 15% | 15% | 15% | 15% | 15% |
| levelized cost ($/bbl) | 63 | 78 | 97 | 100 | 19 | 24 |
| levelized cost ($/gallon) | 1.50 | 1.85 | 2.30 | 2.42 | 0.46 | 0.57 |
| levelized cost ($/liter) | 0.40 | 0.49 | 0.61 | 0.64 | 0.12 | 0.15 |

**TABLE 4. Feedstock Fuel Prices to Achieve Breakeven Cost of FT Fuels and Petroleum-Based Fuels at Several Carbon Taxes and Oil Prices**

| | | coal price ($/metric ton) | | domestic NG price ($/1,000 m$^3$) | | LNG price ($/1,000 m$^3$) | |
|---|---|---|---|---|---|---|---|
| carbon tax ($/metric ton $CO_2$) | oil price ($/bbl) | high emissions | low emissions | high emissions | low emissions | high emissions | low emissions |
| 22 | 40 | 0 | 0 | 159 | 141 | 141 | 124 |
| | 80 | 165 | 154 | 353 | 353 | 353 | 335 |
| | 120 | 331 | 320 | 565 | 547 | 547 | 547 |
| 88 | 40 | 0 | 0 | 124 | 141 | 88 | 88 |
| | 80 | 66 | 154 | 335 | 353 | 283 | 300 |
| | 120 | 220 | 320 | 530 | 547 | 494 | 512 |
| 154 | 40 | 0 | 0 | 88 | 141 | 18 | 53 |
| | 80 | 0 | 154 | 300 | 353 | 230 | 265 |
| | 120 | 132 | 320 | 512 | 547 | 441 | 477 |

petroleum diesel and gasoline, we need to develop an average price for these petroleum-based fuels as well. Using historic crude oil price data and historic prices of gasoline and diesel (*24, 25*) a regression was performed to relate the average price of refiner product to sale for resellers of gasoline and diesel (used as a proxy for refinery gate prices, which is a proxy for production cost) to the refinery acquisition cost of crude oil (the price refineries pay for crude oil). From this regression, which is shown in the Supporting Information, we find that at a refinery acquisition cost of $98/bbl (March 2008 price (*26*)), the average price of gasoline and diesel is $3.18 per gallon ($0.84 per liter). Based on March 2008 energy prices, producing CTL and GTL liquids would be cheaper than petroleum-based fuels. The economic advantage of GTL fuels becomes significant if inexpensive natural gas is available. According to data from the EIA, natural gas prices have increased globally in the past decade (*27*), so cheap natural gas is less available. In addition, assuming that Qatar will provide cheap natural gas for GTL plants may be questionable, since it could instead sell this natural gas in the global market at a high price and without incurring the energy losses associated with converting the natural gas into transportation fuels. Further proof that natural gas prices for GTL plants operated in Qatar are not as low as some may argue is that ExxonMobil announced in 2007 that it would cancel the development of a GTL plant due to rising costs (*5*).

We investigated the impact of a carbon tax on the cost of the alternative fuels using a range of $0 to $220 per metric ton of $CO_2$. As of March 2008 U.S. energy prices ($98/bbl oil, $57/metric ton coal, and $316/1,000 m$^3$ natural gas), if carbon capture and sequestration is not available at FT liquid plants, a carbon tax larger than $154/metric ton of $CO_2$ ($140/ton $CO_2$) would make CTL fuels more expensive than petroleum-based fuels; GTL fuels produced with domestic resources would be cheaper than petroleum-derived fuels at any given carbon tax; and GTL fuels produced with LNG would become more expensive than petroleum-based fuels with a carbon tax higher than $176/metric ton of $CO_2$ ($160/ton $CO_2$). If the FT fuels were produced in the most optimistic scenario previously described (with CCS and using low carbon sources of electricity), CTL fuels and GTL fuels produced with domestic resources would be cheaper than petroleum-derived fuels at any given carbon tax; and GTL fuels produced using imported LNG would reach the same price as petroleum-based fuels once the carbon tax reaches $220/metric ton of $CO_2$ ($200/ton $CO_2$). These results show that at high oil prices, the carbon tax is not sufficient to discourage the production of CTL and GTL fuels.

Energy prices (especially petroleum prices) change constantly, affecting the results discussed in the previous paragraph. For this reason, an analysis was also performed to determine feedstock prices required for FT liquids to be more expensive than petroleum-based fuels at different carbon taxes and oil prices, as seen in Table 4. Table 4 presents values in SI units. Prices of fuels in the U.S. are generally reported in British units ($/short ton, $/MCF) and some readers may find the units in Table 4 confusing. Table S1 in the Supporting Information presents these values in British units.

It can be seen that CTL fuels produced without CCS are not economically feasible at low oil prices ($40/bbl), regardless of the carbon price. At high oil prices ($120/bbl), CTL becomes economically feasible. Coal prices would have to be extremely high (over $130/metric ton) for CTL fuels to become more expensive than petroleum-based fuels. However if the carbon tax is high (\$130/metric ton $CO_2$), the coal price at which CTL fuels produced without CCS become more expensive than petroleum-based fuels is 60% lower than when the carbon tax is low (\$20/metric ton $CO_2$). Interestingly, when CTL fuels are produced in the low-emissions scenario (CCS and low carbon electricity), the carbon tax has no effect on the feedstock prices required for CTL fuels to be more expensive than petroleum-based fuels. This insensitivity to carbon price is due to the life-cycle emissions from CTL fuels and petroleum-based fuels being nearly equal. This same insensitivity is seen for GTL fuels produced with domestic resources in the low-emission scenario.

GTL fuels are not economic at low oil prices (\$40/bbl), especially if these fuels are produced in the high-emissions scenario and the carbon tax is high (\$130/metric ton $CO_2$). Even if oil prices are high (\$120/bbl) and the carbon tax is low, natural gas prices would only have to reach \$550/1,000 $m^3$ or \$15/MCF (not unrealistically high) for GTL fuels to become more expensive than petroleum-based fuels.

So far we have presented the climate change implications of CTL and GTL fuel production and use as well as an analysis of the economic implications of these fuels. When looking at potentially 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. Three petroleum product replacement scenarios are presented in detail in the Supporting Information. In the scenarios where CTL fuels replace petroleum-based fuels, coal consumption by 2030 would be more than double the current projections. Similarly, in the scenario were GTL fuels replace petroleum-based fuels, natural gas consumption by 2030 would also be more than double the current projections. The U.S. domestic natural gas supply is not expected to increase in the coming decades, so if GTL plants were to be built in the U.S., the supply for these plants would likely come from imported sources such as LNG. Alternatively, the fuels could be produced in natural gas-rich countries and imported to the U.S. In these cases, however, we would just transfer our dependence on foreign countries from oil-rich to natural gas-rich countries.

U.S. coal reserves are reported to be abundant, often quoted to last 250 years at current consumption rates. Although a 2007 report by the National Research Council (*28*) states that 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 often reported. If coal consumption rates doubled due to the production of CTL fuels, the long-term availability of economically viable reserves becomes more uncertain.

## 6. Discussion

Alternative transportation fuels are being considered in order to reduce the United States' dependence on foreign sources of petroleum. At the same time concern over climate change due to GHG emissions is increasing, and emissions reduction strategies are being considered. Liquid fuels from coal would provide energy security, as they use a domestic fuel. CTL fuels might even help maintain low transportation fuel prices. But, as this analysis shows, increased use of these fuels would likely increase life-cycle GHG emissions associated with the consumption of transportation fuels. If a life-cycle carbon tax is established, the economic advantage of these CTL fuels over petroleum-derived fuels may be reduced. In addition, any effort to increase production with CTL fuels implies a significant increase in coal consumption. Finally, significant increases in demand for coal would likely raise prices, especially if there is a decrease in supply of easily recoverable coal. These factors add to the uncertainty as to the economic advantages of CTL fuels.

GTL fuels from domestic natural gas could, in the most optimistic scenario, produce a slight reduction in GHG emissions, but it is unlikely that these natural gas-derived fuels would contribute to our energy security. Supply of North American natural gas is limited, so increased supply would have to come from foreign sources, which would maintain our dependence of foreign sources of fuels (and increase emissions). Additionally, it is not clear that these fuels would help maintain lower liquid fuel prices. If the U.S. has a goal of increasing its energy security, and at the same time significantly reducing its GHG emissions, neither CTL nor GTL consumption seem a reasonable path to follow.

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## Note Added after ASAP Publication

This paper published ASAP September 18, 2008 with errors in Table 1, text and Supporting Information; the corrected version published ASAP October 13, 2008.

## Supporting Information Available

Supporting Information is available for this paper. This information is available free of charge via the Internet at http://pubs.acs.org.

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