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Synthetic fuels in a world with high oil and carbon prices

Robert H. Williams[1], Eric D. Larson[1], Haiming Jin[2]

[1]Princeton Environmental Institute, Princeton University
Guyot Hall, Washington Road, Princeton, NJ, 08544, USA

[2] TX Energy, 1330 Post Oak Blvd, Suite 1600, Houston, TX, 77056, USA

Abstract

Four carbon management options are investigated for making Fischer-Tropsch fuels plus electricity: three processing coal and one co-processing coal and biomass. Energy and carbon balances are estimated. Economic analyses are carried out for carbon prices of $0 and $100 per tonne of carbon. Both levelized costs and internal rates of return on equity are estimated with CO_2 vented, and with CO_2 captured and stored in saline aquifers, and with CO_2 captured and used for enhanced oil recovery. Comparisons are made with coal integrated gasifier combined cycle power plants. When the carbon price is $100 per tonne of carbon, the co-processing option is the most economically attractive option for making Fischer-Tropsch liquids. Even at zero carbon price enhanced oil recovery applications of captured CO_2 will often be economically attractive where such opportunities exist. Enhanced oil recovery is a sufficiently large and economically interesting niche in the USA (and perhaps elsewhere) that it could enable wide near-term experience with gasification-based energy and carbon capture and storage technologies.

Keywords: coal, biomass, Fischer-Tropsch, gasification, CO_2, EOR

Introduction

Carbon management options are investigated for Fischer-Tropsch (F-T) liquids—synthetic fuels that have attracted interest in light of high oil prices and oil supply security concerns.

The system configurations investigated are “polygeneration” units that use commercial “once-through” liquid-phase reactors with iron-based catalyst for synthesis of F-T fuels from syngas. The syngas unconverted in a single pass is used to make co-product electricity in a combined cycle power plant. Liquid-phase synthesis reactors and once-through synthesis configurations are well-suited for use with CO-rich syngas—such as that derived from coal via gasification.

Three carbon management options for systems using only coal are considered: one that vents the CO_2 coproduct (C-FT-V); one (Figure 1a) that captures CO_2 and stores it underground (C-FT-C); and one that involves co-capture and underground co-storage of CO_2 and H_2S (C-FT-CoC). In a fourth option (Figure 1b) coal and biomass are co-processed with co-capture and underground co-storage of CO_2 and H_2S (C/B-FT-CoC). For the co-processing option H_2 from biomass supplements H_2-deficient coal syngas in

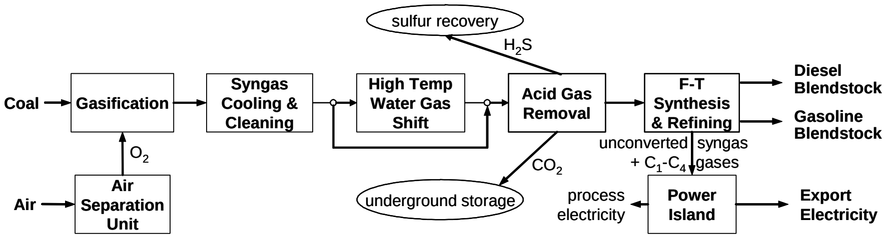

Figure 1a: Process configuration for C-FT-C energy system.

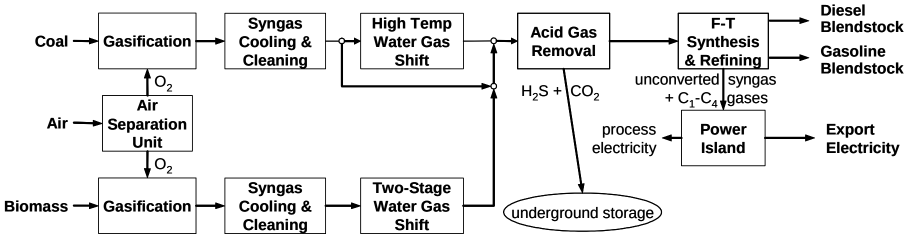

Figure 1b: Process configuration for C/B-FT-CoC energy system.

making F-T liquids, exploiting the negative emissions potential of CO_2 capture and storage (CCS) for biomass [1].

The biomass calculations are for switchgrass, which was also investigated in a companion bioenergy study [1]. Results for crop residues (an early market opportunity for biomass) are likely to be similar to the findings presented for switchgrass.

Energy and carbon balances are estimated. The economic analyses include calculations of both levelized costs and internal rates of return on equity. In the economic analyses aquifer storage (CO_2-AqS) and enhanced oil recovery (CO_2-EOR) are considered as alternative storage options. For CO_2–EOR, comparisons are made to using CO_2 from coal integrated gasifier combined cycle (IGCC) power plants.

Methodology

F-T liquids plants were modeled using: (*i*) AspenPlus chemical process simulation software to estimate detailed mass and energy balances and (*ii*) AspenPinch software for system heat integration. A GE pressurized, O_2–blown, entrained flow, quench gasifier (commercially available) is modeled for coal. C/B-FT-CoC involves modeling a separate pressurized, O_2–blown, fluidized bed gasifier based on GTI's technology (not yet commercial) for biomass but a sharing of other process equipment between coal and biomass.

For C-FT-V, syngas from the gasifier is shifted to the extent that H_2:CO = 2.25 for syngas entering the synthesis reactor—the value that maximizes conversion to liquid fuel. For CCS cases, H_2:CO = 2.75—a value at which essentially all carbon (except in CH_4) entering the synthesis reactor leaves as F-T products, and syngas conversion to liquids is only slightly below the maximum value.

After shifting the syngas, CO_2 and H_2S are captured using Rectisol technology. The CO_2 is dried and compressed or the CO_2 + H_2S are dried and compressed to 150 bar and transported 100 km to a site for storage in a saline aquifer 2 km underground or in conjunction with CO_2-EOR.

The products of F-T synthesis (light gases, naphtha, middle distillates, and waxes) are sent to an integrated refinery area, the final liquid products from which are gasoline and diesel blendstocks; the light (C_1-C_4) gaseous byproducts of refining plus the unconverted syngas exiting the synthesis reactor are burned for power generation in a combined cycle plant.

For simulated energy and mass balances, installed capital costs were estimated for the four F-T plant configurations, assuming commercially-ready components for coal and future mature N^{th} plant technology components for biomass. Capital costs were developed by sub-unit in each major plant area using a database developed from prior work [1,2,3,4], literature studies, and discussions with industry experts.

Energy quantities are expressed on a lower heating value (LHV) basis, except energy prices are on a higher heating value (HHV) basis—the norm for US energy pricing. All costs are in 2003$. It is assumed that prices for coal and biomass (20% moisture content) are \$1.35/GJ_{HHV} and \$3.0/GJ_{HHV} (which is likely to be typical for many residue and dedicated energy crop applications), respectively. Energy system costs are estimated for greenhouse gas (GHG) emissions having monetary values of \$0 and \$100 per tonne of carbon equivalent (tC_{equiv}).

In systems producing both F-T liquids and electricity, allocation of GHG emissions[1] and costs between the products is arbitrary. For the present analysis it is assumed that the GHG emission rate assigned to electricity (gC_{equiv}/kWh) is that for a stand-alone coal IGCC plant with CO_2 vented (C-IGCC-V) in the C-FT-V case and for a coal IGCC plant with CO_2 captured (C-IGCC-C) in all capture cases. In estimating F-T liquids production costs at a given monetary value for GHG

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[1] The GHG emissions include CO_2 emissions from the plant and ultimate combustion of the F-T liquids and the CO_2-equivalent GHG emissions upstream of the conversion plant. From the GREET model of the Argonne National Laboratory these are estimated as 1.00 kgC_{equiv} and 2.06 kgC_{equiv} per GJ for coal and switchgrass, respectively.

emissions, it is assumed that the value of the co-product electricity ($/kWh) equals the generation cost for the least-costly stand-alone C-IGCC power plant for that monetary value of GHG emissions.

Table 1: F-T liquids production with CO_2 vented or aquifer storage of CO_2 (Base Case financing)

Conversion Option	**C-FT-V**		**C-FT-C**		**C-FT-CoC**		**C/B-FT-CoC**	
Carbon flows (power balances)								
Coal input, kgC/s (MW)	74.2 (2946)		77.7 (3085)		77.7 (3085)		56.4 (2241)	
Switchgrass input, kgC/s (MW)							24.7 (886.8)	
F-T liquids output, kgC/s (MW)	21.1 (1035)		21.0 (1032)		21.0 (1033)		20.9 (1032)	
Electric power output (MW)	(461.3)		(429.9)		(428.3)		(459.5)	
Unconverted coal char, kgC/s	0.74		0.78		0.78		0.56	
Coal CO_2 emissions from plant, kgC/s	52.5		8.27		6.94		6.64	
Coal CO_2 captured & stored, kgC/s [CO_2 capture rate for coal (CCR_C), t CO_2 /GJ_{FTL}]			47.6 [0.169]		49.0 [0.174]		28.3 [0.101]	
Switchgrass CO_2 captured and stored, kgC/s [CO_2 capture rate for switchgrass (CCR_S), t CO_2/GJ_{FTL}]							22.3 [0.0791]	
Fuel cycle GHG emissions, kgC_{equiv}/GJ_{LHV} F-T liquids (relative to crude oil-derived hydrocarbon fuels)	46.73 (1.80)		27.98 (1.08)		26.68 (1.03)		5.53 (0.21)	
Fuel cycle GHG emission rate, gC_{equiv}/kWh electricity	219.4		28.8		28.8		28.8	
Price of GHG emissions, $/$tC_{equiv}$	0	100	0	100	0	100	0	100
Electricity co-product value, ¢/kWh	4.75	6.94	4.75	6.94	4.75	6.94	4.75	6.94
Overnight construction cost, $$10^6$	1647		1797		1639		1678	
CO_2 transport/storage cost, $/t CO_2			6.59		6.47		6.50	
F-T Liquids Production Cost, $/$GJ_{LHV}$								
Capital	10.63		11.63		10.60		10.87	
Operation and maintenance	2.52		2.76		2.52		2.58	
Coal input	4.01		4.21		4.20		3.06	
Switchgrass input							2.86	
Electricity co-product credit	-5.88	-8.59	-5.49	-8.03	-5.47	-7.99	-5.87	-8.58
CO_2 transport/storage cost (CTSC)			1.11		1.12		1.17	
GHG emissions cost	-	7.38	-	3.14	-	3.00	-	3.07
Credit for bio-CO_2 storage								-2.16
Net production cost, $/$GJ_{LHV}$ (NPC = NPC_V for venting and NPC_C for capture)	11.28	15.96	14.22	14.82	12.97	13.46	14.65	12.85
F-T liquids prod cost, $/liter gasoline equivalent (ge)	0.355	0.502	0.447	0.466	0.408	0.423	0.461	0.404
Breakeven crude oil price, $/barrel	50.4	61.7	66.2	55.6	59.6	48.2	68.6	44.9
Plant-gate CO_2 cost = (NPC_C - CTSC - NPC_V)/(CCR_C + CCR_S), $/t CO_2			10.7	-13.3	3.3	-20.9	12.3	-23.8

Cost estimates are for plants with an 80% capacity factor, financing with 55% debt (4.4%/y real cost) and 45% equity, a 30-year (20-year) plant (tax) life, a 38.2% corporate income tax rate, a 2%/y property tax/insurance rate, and an owner's cost of 5.5% of the total installed capital cost. Base Case financing involves a 14.0% real rate of return on equity (ROE), so that the discount rate (real weighted after-tax cost of capital) is 7.8%/year, and the levelized annual capital charge rate is 15.0%/year. Plant construction requires four years, with the capital investment committed in four equal payments, so that interest during construction is 12.3% of the overnight construction cost.

Costs for CO_2 transport and for aquifer storage are based on a model developed by Ogden [5], assuming that the maximum CO_2 injection rate per well for the AqS-CO_2 storage cases is 1000 t/day, a typical value for mid-continental aquifers.

Breakeven crude oil prices are estimated assuming that the F-T gasoline and diesel products (38% and 62% of liquids output, respectively) compete with gasoline and low-sulfur diesel derived from crude oil. The refining cost increment for this mix is $10.4 per barrel.

For the CO_2-EOR cases, captured CO_2 is transported 100 km and sold for EOR at a price in $ per 10^3 scf (1 tonne = 19 x 10^3 scf) equal to 3% of the oil price in $/barrel—a "rule of thumb" for Permian Basin CO_2-EOR (Vello Kuuskraa, ARI, private communication, December 2005).

With Base Case financing, the economic analysis identifies the crude oil price at which F-T liquids are competitive with gasoline and diesel. Electricity costs for coal IGCC power with CO_2–EOR are also estimated with Base Case financing. The economic analysis is extended beyond Base Case financing to estimate the ROE as a function of oil price—assuming all financial parameters other than the ROE are the same as with Base Case financing.

Findings

Table 1 summarizes energy and carbon balances and the economic analysis with Base Case financing for systems with venting and aquifer storage of CO_2. With CO_2 vented, the GHG emission rate is 1.8 times that for crude-derived hydrocarbon (HC) fuels displaced, but for coal with CCS the rate is about the same as for these HC fuels, and for C/B-FT-CoC the rate is only 0.2 times that for displaced HC fuels.

Notably, only 0.86 GJ of biomass is needed to make 1 GJ of F-T liquids via C/B-FT-CoC. This is far less than the biomass required to make conventional liquid biofuels[2] and thus offers an attractive way to use scarce biomass resources to make liquid fuels with near-zero net GHG emissions.

At \$0/tC the C-FT-V option competes at \$50 a barrel crude oil, but the CCS options require a much higher oil price to be economically interesting. However, at \$100/tC [the GHG emissions price at which C-IGCC-C (CO_2-AqS) becomes competitive with C-IGCC-V—see Table 3], the C/B-FT-CoC option would compete at a \$45/barrel oil price and provide F-T liquids at a plant-gate cost of \$0.40/liter (\$1.5/gallon) of gasoline equivalent (ge).

Plant-gate costs of CO_2 are low—\$3-\$12/t (Table 1), lower than for C-IGCC-C plants (see Table 3)—suggesting that F-T liquids plants might be attractive sources of CO_2 for EOR projects. Table 2 presents an economic analysis for F-T plants coupled to CO_2-EOR with Base Case financing, showing that breakeven crude oil prices are in the range \$37-\$42/barrel for \$0/tC (much lower than for C-FT-V, Table 1). Similarly, Table 3 shows that C-IGCC-C supporting CO_2-EOR could provide less costly electricity than C-IGCC-V at \$0/tC.

Projects coupling gasification energy and CO_2-EOR could help establish CCS technologies in the market even at a carbon price of \$0/tC. Recent studies [8] estimated for 10 US basins/regions the economic (technical) CO_2-EOR potential based on state-of-the-art technology to be 47 (89) billion barrels. The economic potential could support 4.3 million barrels/day of crude oil production for 30 years (a typical lifetime for a gasification energy plant that might provide the needed CO_2). At the average CO_2 purchase rate of 0.21 t CO_2/barrel estimated in these studies, the required CO_2 could in principle be provided by 60 C-FT-C plants (Table 2) or 126 C-IGCC-C plants (Table 3). Although coupling gasification energy and CO_2–EOR projects will not always be feasible, this “niche activity” would nevertheless be large enough to gain extensive early experience and technology cost buydown (learning by doing) for both gasification energy and CCS technologies.

Figures 2a and 2b show the ROE as a function of oil price at \$0/tC and \$100/tC, respectively. At \$0/tC, the CO_2-EOR-supporting options would almost always be more profitable than C-FT-V; C-IGCC-C supporting CO_2-EOR is the most profitable option at low oil prices but FT-C options supporting CO_2-EOR are more profitable at high oil prices. At \$100/tC, C-IGCC-C with CO_2-EOR is the most profitable option, and C/B-FT-C (characterized by near-zero GHG emission rates for both F-T liquids and electricity) is more profitable than any C-FT option at all oil prices and for both storage options (CO_2-EOR and CO_2-AqS).

Conclusions

Making F-T liquids from coal could help mitigate oil supply security concerns and would be profitable at sustained high oil prices. But without CCS, this option would lead to a large increase in

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[2] For comparison, the net biomass required to make 1 GJ of F-T liquids from switchgrass with CO_2 vented is 1.56 GJ [1], while the net biomass required to make 1 GJ of cellulosic ethanol from corn stover is 2.89 GJ with vintage 2000 technology (58.4 gallons per dry short ton) [6] and 1.77 GJ with advanced technology (89.8 gallons/ton) [7].

GHG emissions relative to hydrocarbon fuels derived from crude oil.

With CCS, the GHG emission rate for coal F-T liquids could be reduced to about the rate for crude oil-derived fuels. The net GHG emission rate could be reduced further, to near zero, via co-processing biomass and coal with CCS so as to exploit the negative emissions of storing photosynthetic CO_2. At a carbon price of $100/tC the co-processing option is the most economically attractive of all the options considered for F-T liquids production and requires far less net biomass input to realize near zero GHG emissions than conventional biofuels such as cellulosic ethanol.

If the CO_2 captured in F-T or IGCC plants were used for CO_2-EOR, the economics of CO_2 capture and storage would often be attractive even at a carbon price of $0/tC. CO_2-EOR opportunities in the USA (and perhaps elsewhere) are sufficiently large to make the CO_2-EOR application an attractive way to gain extensive near-term experience with gasification-based energy and CCS technologies and the opportunity to “buy down” the costs of these technologies substantially as a result of learning by doing.

Table 2: Economics of F-T liquids production if CO_2 is used for EOR (Base Case financing)

Conversion Option	**C-FT-C**		**C-FT-CoC**		**C/B-FT-CoC**	
CO_2 available for EOR, t CO_2/hour	628.4		646.0		667.5	
Barrels of crude EOR/barrel of F-T liquids (ge)	4.00		4.11		4.25	
Price of GHG emissions, $/tC$_{equiv}$	0	100	0	100	0	100
Electricity co-product value, ¢/kWh	4.75	6.94	4.75	6.94	4.75	6.94
Price at which CO_2 is sold for EOR, $/t CO_2	23.6	19.6	20.9	16.5	23.9	15.2
CO_2 transport cost (100 km), $/t CO_2	2.94		2.89		2.84	
F-T Liquids Production Cost, $/GJ$_{LHV}$						
Capital	11.63		10.60		10.87	
Operation and maintenance	2.76		2.52		2.58	
Coal input	4.21		4.20		3.06	
Biomass input					2.86	
Electricity co-product credit	-5.49	-8.03	-5.47	-7.99	-5.87	-8.58
CO_2 transport cost	0.50		0.50		0.51	
GHG emissions cost	-	3.14	-	2.92	-	3.07
Credit for EOR	- 3.99	- 3.31	- 3.63	- 2.86	- 4.30	- 2.73
Credit for bio-CO_2 storage						-2.16
Net F-T liquids production cost, $/GJ$_{LHV}$	9.61	10.89	8.73	9.89	9.70	9.46
F-T liquids production cost, $/liter, ge	0.302	0.342	0.274	0.311	0.305	0.298
Breakeven crude oil price, $/barrel	41.4	34.4	36.6	28.9	41.9	26.7

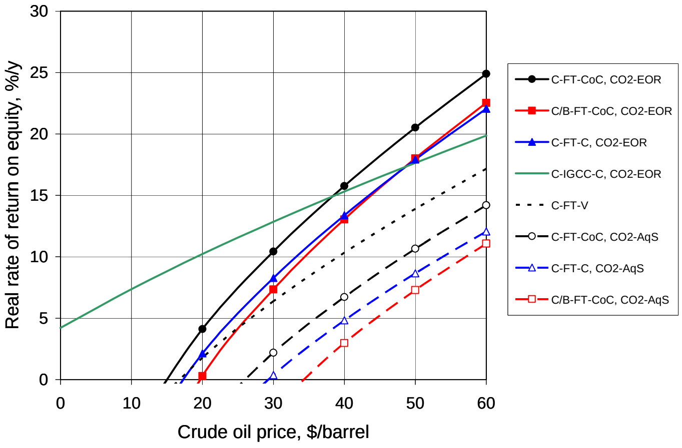

Figure 2a: ROE vs. oil price @ $0/tC.

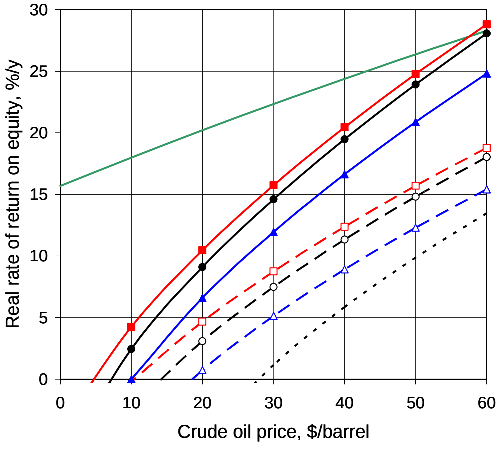

Figure 2b: ROE vs. oil price @ $100/tC.

Table 3: Performances and costs for coal IGCC power plants[a] (Base Case financing)

Conversion Option	**C-IGCC-V**		**C-IGCC-C**			
Storage mode			CO_2-AqS		CO_2-EOR	
Price of GHG emissions, \$/tC_{equiv}	0	100	0	100	0	100
Installed capacity, MW_e	390.1		361.9			
CO_2 storage rate, t CO_2/hour			297.3			
Barrels of crude EOR per day/GW_e of C-IGCC-C capacity			74,700			
CO_2 emission rate from plant, t CO_2/hour	301.5		25.2			
Fuel cycle GHG emission rate, gC_{equiv}/kWh	219.4		28.8			
Efficiency at design point, LHV	42.95		36.79			
CO_2 transport cost, \$/t CO_2			4.33			
CO_2 storage cost, \$/t CO_2			3.84		-	
Price at which CO_2 is sold for EOR, \$/t CO_2—assumed to be the same as for the C-FT-C option in Table 2 (assumed crude oil price, \$/barrel)					23.6 (41.4)	19.6 (34.4)
Overnight construction cost (OCC), \$/kW_e	1187		1531			
Generation Cost, ¢/kWh						
Capital	2.85		3.68			
Operation and maintenance	0.68		0.87			
Fuel	1.22		1.42			
CO_2 transport			0.36			
CO_2 storage			0.31		-	
Credit for EOR					- 1.94	- 1.61
GHG emissions	0	2.19	0	0.29	0	0.29
Total	4.75	6.94	6.64	6.93	4.39	5.01
Plant-gate CO_2 cost, \$/t CO_2			14.8	- 8.3		

[a] Based on [4] except that (as for the F-T polygeneration analysis) the coal is assumed to have a heating value of 23.5 GJ_{LHV}/tonne and a C content of 25.2 kgC/GJ_{LHV}.

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