Coal and Biomass to Fuels and Power

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Abstract

Systems with CO_2 capture and storage (CCS) that coproduce transportation fuels and electricity from coal plus biomass can address simultaneously challenges of climate change from fossil energy and dependence on imported oil. Under a strong carbon policy, such systems can provide competitively clean low-carbon energy from secure domestic feedstocks by exploiting the negative emissions benefit of underground storage of biomass-derived CO_2, the low cost of coal, the scale economies of coal energy conversion, the inherently low cost of CO_2 capture, the thermodynamic advantages of coproduction, and expected high oil prices. Such systems require much less biomass to make low-carbon fuels than do biofuels processes. The economics are especially attractive when these coproduction systems are deployed as alternatives to CCS for stand-alone fossil fuel power plants. If CCS proves to be viable as a major carbon mitigation option, the main obstacles to deployment of coproduction systems as power generators would be institutional.

INTRODUCTION

CCS: CO_2 capture and storage

EtOH: ethanol

This article reviews a novel approach for simultaneously:

- decarbonizing coal power and transportation fuels, which accounted for, respectively, 30% and 22% of global CO_2 emissions from fossil fuel burning in 2007 (1); and
- reducing liquid fuel supply insecurity by providing synthetic liquid transportation fuels from secure supplies of coal plus renewable biomass[1] that can be generated from lignocellulosic feedstocks in ways that minimize adverse impacts.[2]

This approach involves coprocessing coal and lignocellulosic biomass via thermochemical gasification to coproduce electricity and transportation fuels with CO_2 capture and storage (CCS) in the system described in **Figure 1**. The carbon mitigation potential and economics of this approach to decarbonization are attractive. Moreover, the low-carbon fuels produced require only 40% to 50% as much scarce biomass per gigajoule of transportation fuel as is required for advanced biofuels such as cellulosic ethanol (EtOH).

This approach would go a long way toward eliminating tensions that have seemed to be inherent among goals for low-cost transportation services, for liquid fuel supply security enhancement, and for carbon mitigation. This approach offers a way to sustain roles for low-cost internal-combustion-engine transportation vehicles in a carbon-constrained world. Under this approach, such vehicles would use easy-to-store, superclean, low-carbon gasoline, diesel, and jet fuel derived from secure domestic resources. These fuels would be very cost-competitive under a carbon-mitigation policy, and their introduction would require no significant transportation fuel infrastructure changes.[3,4]

This approach to energy would exploit simultaneously the following key concepts for a carbon-constrained and energy-insecure world:

1. CCS for electricity from fossil fuels,
2. CCS for the production of synthetic liquid transportation fuels,
3. CCS for biomass energy,
4. Coprocessing of biomass and coal to make synthetic fuels in systems with CCS, and
5. Coproduction of synthetic liquid transportation fuels and electricity with CCS.

Despite the seeming complexity of this approach to energy, first-generation systems can be launched in the market during this decade using technological components that are near at hand. Aside from establishing the viability of CCS as a major carbon mitigation option, the challenges are

[1] Biomass is renewable if one tonne of new biomass is grown for each tonne consumed.

[2] The adverse impacts include (2): loss of biodiversity, conflicts with food production (3), and enhanced greenhouse gas (GHG) emissions from direct (4) and indirect (5) land-use impacts. Strong candidate feedstocks are various crop and forest residues and biomass that can be grown as a dedicated energy crop on abandoned cropland (2, 6).

[3] An alternative approach to addressing these challenges is to introduce hydrogen as an energy carrier for transportation. But slow progress in reducing hydrogen fuel cell vehicle costs, the inconvenience and high costs of hydrogen storage, and the huge costs of shifting the transportation fuel infrastructure from hydrocarbon fuels to hydrogen (7) have led the Obama administration to try to greatly deemphasize federal energy R&D relating to the hydrogen economy for transportation, but with congressional opposition.

[4] Still another approach is to electrify transportation. However, the 40% of global transportation fuel use by airplanes and in long-haul truck freight and marine applications (8) will not be easily electrified. Although battery technologies for meeting the needs of conventional hybrid-electric vehicles are well established in the market, it is unclear if the long-life, deep-discharge batteries needed for plug-in hybrids and all-electric cars will be developed successfully. Moreover, costs for both plug-in hybrids and all-electric vehicles are extremely high, and these costs likely will come down only slowly over several decades, because costs for a key enabling technology (lithium ion battery) have already fallen substantially as a result of early deployment in cell phone and laptop computer applications (9). Electrification might prove to be an attractive strategy for new kinds of ultrasmall vehicles used for short trips.

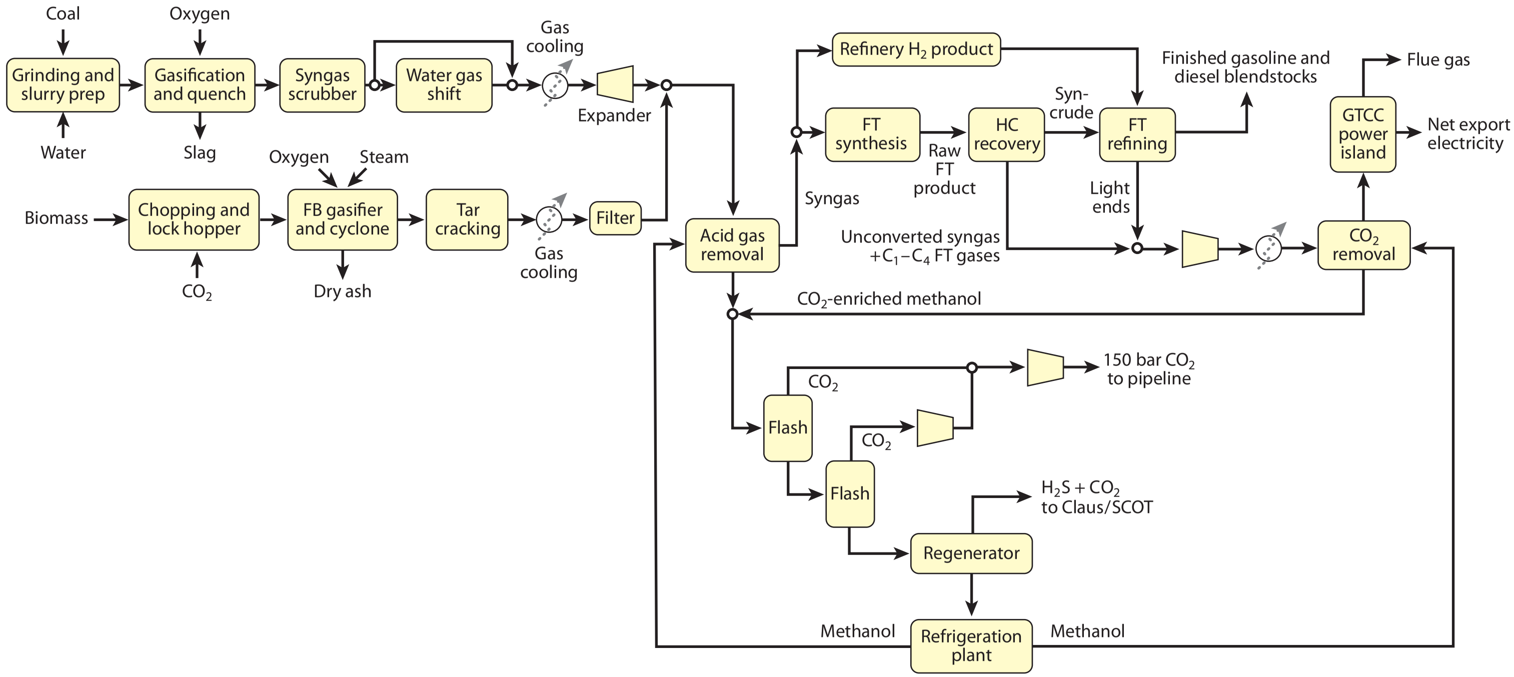

Figure 1

Plant layout for the coal/biomass to Fischer-Tropsch liquid (FTL) synthetic fuels once-through-CO_2 capture and storage (CBTL-OT-CCS) process modeled in Reference 10. Assumptions: separate O_2-blown gasifiers for bituminous coal (General Electric Energy entrained-flow water-slurry-fed quench gasifier) and for switchgrass [Gas Technology Institute fluidized bed (FB) gasifier]; FTL obtained via slurry-phase synthesis with iron catalyst; $H_2/CO = 1.0$ for synthesis gas (syngas) entering the synthesis reactor; on-site refining to upgrade crude FTL products to finished diesel and gasoline; CO_2 and H_2S separated from shifted syngas in an acid gas removal (AGR) unit using Rectisol; H_2S recovered in AGR unit is reduced to elemental S in a Claus/SCOT (Shell Claus Off-gas Treating process) plant; CO_2 is compressed to 150 bar for transport to storage; residual H_2-rich syngas is mixed with N_2 from the air separation unit (for NO_x control) and burned in the combustor of a gas turbine combined cycle (GTCC).

ANALYTICAL CONTEXT

Liu et al. (10), who wrote the article that provides the basis for much of the quantitative analysis presented in this review, analyzed 16 different system configurations for making FTL synthetic fuels, including synfuels from coal (CTL), from biomass (BTL), and from coal + biomass (CBTL); CO_2-venting (V) and CCS options; and recycle (RC) and once-through (OT) plant configurations. The study evaluated the economics of coproduction from the perspectives of both a synthetic fuel producer and an electricity generator for new construction applications.

As a result of a systematic comparison of these alternative system configurations, Liu et al. (10) conclude that the CBTL-OT-CCS system described in **Figure 1** and **Supplemental Table 2** (and the centerpiece of this review) offers substantial benefits relative to the other systems described here.

Liu et al. (10) represents a refinement and an extension of an earlier study (11) for the same 16 FTL synthetic fuel system configurations. In Reference 11, the economic analysis was carried out only from the synthetic fuel producer's perspective.

Supplemental Material

mainly institutional rather than technological, and the prospective attractive economics provides a strong incentive for finding ways to overcome institutional obstacles.

The literature is reviewed by considering each of the five concepts in turn. There is a substantial literature relating to the first and third concepts, a significant literature on the second and fourth, but only a modest number of articles on the fifth. Because the literature on the fifth concept is sparse and not widely known but key to attractive prospective energy economics under a carbon policy constraint, the review of the last element is mainly in the form of an exposition on the strategic importance of coproduction (especially for systems that also involve the other four concepts) that draws largely on the analysis of Liu et al. (10), which evaluated many system configurations for making Fischer-Tropsch liquid (FTL) synthetic fuels. The configurations examined (see sidebar on Analytical Context) included those that use as feedstocks coal, biomass, and coal + biomass; those that make primarily liquid fuels; those that provide electricity as a major coproduct; and those that vent CO_2 as well as those that involve CCS.

After reviewing the literature for each of the five areas, an original analysis (based on modeling in Reference 10) offers an economic perspective as a response to the question: What is the optimal way to use biomass energy with CCS in a carbon-constrained world? This is followed by a short section aimed at putting the coal and biomass to fuels and power concept into a technological innovation theoretical context. The penultimate section discusses challenges and public policy issues.

The qualitative implications of the findings of the reviewed publications are emphasized. However, all the detailed quantitative analysis, which puts a strong emphasis on economics, is based on a self-consistent set of assumptions discussed in the Analytical Framework section of the **Supplemental Text** (follow the **Supplemental Material link** from the Annual Reviews home page at **http://www.annualreviews.org**).

For the quantitative analysis, two metrics for greenhouse gas (GHG) emissions mitigation are introduced: a GHG emissions index (GHGI) that measures total fuel-cycle-wide GHG emissions for energy production and consumption relative to emissions for the fossil energy displaced, and the GHG emissions avoided (GHGA), which is related to GHGI via:

$$\text{GHGA} = (1 - \text{GHGI})\,(\text{fuel-cycle-wide GHG emissions for the fossil energy displaced}).$$

For a more detailed discussion on how to use these indices in alternative applications, see the Analytical Framework section in the **Supplemental Text**.

Fischer-Tropsch liquid (FTL) synthetic fuels (diesel and gasoline): produced here in slurry-phase synthesis reactors using an iron catalyst for synthesis and Rectisol for acid gas removal

Greenhouse gas emissions index (GHGI): (fuel-cycle-wide GHG emissions for production + consumption of a plant's energy products)/(GHG emissions for the fossil fuel products displaced)

Greenhouse gas emissions avoided (GHGA): (1 – GHGI)(GHG emissions of fossil energy displaced)

GHGI is a helpful metric in measuring GHG emissions mitigation in relation to overall societal goals for emissions reduction. For example, if a nation's goal is an 80% reduction in total emissions over a certain time period, it would aim to promote technologies for which GHGI ≤ 0.2. GHGA can be helpful in better understanding, for a given emissions reduction goal (i.e., a given GHGI level), how alternative technologies compare with regard to overall carbon mitigation. The GHGI and GHGA metrics can be characterized as measuring, respectively, the depth and breadth of mitigation. Considering these two metrics simultaneously is especially helpful in understanding the carbon mitigation features of systems that produce both FTL synthetic fuels and electricity as major coproducts.

NGCC: natural gas to electricity via combined cycle

Because most of the technological components for systems discussed in this paper are either established commercially or could be established within the coming decade, it has been possible to make plausible cost estimates for the systems analyzed on a component-by-component basis (for details, see the Analytical Framework section in the **Supplemental Text**). Although absolute system cost levels cannot be known with a high degree of confidence until a few of the analyzed systems are actually built, the relative costs for the alternative systems analyzed should be relatively realistic.

CO_2 CAPTURE AND STORAGE FOR ELECTRICITY FROM FOSSIL FUELS

The Intergovernmental Panel on Climate Change (IPCC) in the climate change mitigation subreport of its *Fourth Assessment Report* (12) concluded that global GHG emissions must be reduced by 50% to 85% by 2050 if global warming is to be confined to between 2.0 and 2.4°C. G8 leaders agreed at the Heiligendamm Summit in 2007 to consider seriously a global 50% CO_2 emissions reduction target by 2050 and a reduction of 80% or more in the already industrialized countries.

CCS is likely to play a substantial role in achieving global carbon mitigation goals. The IPCC (13) estimated that CCS will provide 15% to 55% of the cumulative mitigation effort in the period to 2100. The International Energy Agency (IEA) (8) developed a global energy scenario to 2050 showing that a broad range of technologies is required to meet the G8 goal of a 50% reduction in CO_2 emissions by 2050 relative to 2005. In particular, this IEA report estimated that CCS might account for approximately one-fifth of the overall carbon mitigation effort needed by 2050. In this projection, CO_2 would be stored worldwide at a rate of 10.4 billion t year^{-1} in some 3,400 projects by 2050, and cumulative CO_2 storage through 2050 worldwide would be 145 billion t. The IEA (8, 14) estimates that the global cost of reducing CO_2 emissions from fossil fuels by 50% by 2050 (the goal of G8 leaders) will be approximately 70% higher if CCS is not included among carbon mitigation options.

CCS is key to dealing with coal (the most abundant and least costly but also the most carbon-intensive fossil fuel) in a carbon-constrained world (13)—especially for electricity generation.[5] Although natural gas to electricity combined cycle (NGCC) power plants have a GHG emission rate that is approximately half of that for a modern pulverized coal power plant (see **Supplemental Text**), CCS would also have to be pursued for natural gas power plants, at least in already industrialized countries, if the 80% mid-century emissions reduction target for these countries is to be realized.

[5]In 2007 the percentage of coal-derived CO_2 emissions arising from electricity generation was 71% worldwide, 85% in Organisation for Economic Cooperation and Development (OECD) countries, and 93% in the United States (1).

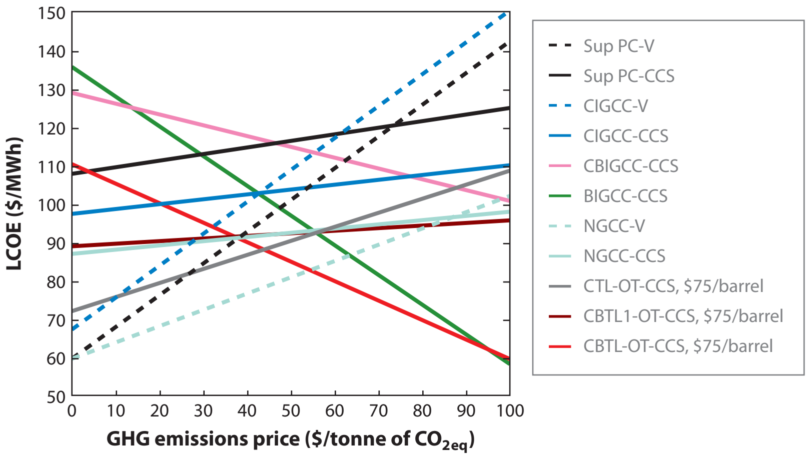

Figure 2

Levelized cost of electricity (LCOE) versus greenhouse gas emissions price (P_{GHGE}) for the 11 electric power plants listed in **Supplemental Table 2** calculated under the assumptions of **Supplemental Table 1**. Abbreviations: CCS, CO_2 capture and storage; NGCC, natural gas to electricity via combined cycle power plant; OT, once-through; Sup PC: supercritical pulverized coal power plant; V, CO_2 venting; XIGCC, X [X = coal (C), biomass (B), or coal/biomass (CB)] to electricity via integrated gasifier combined cycle power plant; XTL, X [X = coal (C), biomass (B), or coal/biomass (CB)] to Fischer-Tropsch synthetic liquid fuels. The 1 in CBTL1-OT-CCS indicates first generation technology with only 12% biomass in feedstock on an energy basis (compared to 40% biomass for CBTL-OT-CCS).

-CCS: a plant that captures CO_2 for storage in a geological formation

XIGCC: X [X = coal (C), biomass (B), or coal + biomass (CB)] to electricity via integrated gasifier combined cycle

LCOE: 20-year levelized cost of electricity generation in dollars per megawatt hour

P_{GHGE}: price of greenhouse gas emissions in dollars per tonne of CO_2 equivalent

Sup PC: coal to electricity via new supercritical pulverized coal plant

-V: a plant that vents all CO_2

Because there is a vast literature on CCS for fossil fuel electricity generation and this CCS application is much less germane than the others, only those aspects of CCS for electricity generation at stand-alone power plants that are most relevant to the topic of the present paper are reviewed here.

When CCS is pursued for a fossil fuel power plant, approximately 90% of the feedstock carbon can be captured as CO_2 and stored underground with current and near-commercial technologies. Currently the least costly CCS options (15, 16) for new bituminous coal power plants[6,7] and natural gas power plants (the focus of the present analysis) are, respectively, a coal integrated gasifier combined cycle with precombustion CO_2 capture (CIGCC-CCS) and an NGCC with postcombustion CO_2 capture (NGCC-CCS). Modeling assumptions for these power systems and others are presented in **Supplemental Tables 1** and **2**. The levelized cost of electricity (LCOE) versus GHG emissions price (P_{GHGE}) curves for each of the new power systems compared are presented in **Figure 2**.

For the coal case, the GHG emissions price (P_{GHGE}) required to induce a shift from Sup PC-V, a new supercritical pulverized coal (Sup PC) plant that vents CO_2 (-V) (currently the least costly option for providing coal electricity when CO_2 is vented), to a new CIGCC-CCS plant via market

[6]In rapidly growing industrializing countries such as China, CCS for new coal power plants will be an important activity. In the United States, where electricity demand is likely to grow slowly under a C-mitigation policy (17), the pursuit of CCS at existing coal power plant sites is likely to be the dominant CCS activity for coal power.

[7]In contrast, if CCS were pursued at a site of an old (written-off) coal power plant, the LCOE for a postcombustion CCS retrofit would be less than that for repowering the site with a new CIGCC-CCS plant. The retrofit is less costly largely because the capital investment required is only approximately one-third as large as for repowering via CIGCC-CCS (18).

forces is \$53/t CO_{2eq}.[8] Measuring the LCOE relative to that for the least costly coal power system in the absence of a carbon mitigation policy (Sup PC-V at \$0/t CO_{2eq}) is helpful in understanding the cost of decarbonization. Under the modeling assumptions, the LCOE (including the value of GHG emissions at the P_{GHGE} needed to induce CCS) is 76% more than the LCOE for Sup PC-V at P_{GHGE} = \$0/t CO_{2eq}. For the NGCC-CCS case, P_{GHGE} = \$88/t CO_{2eq} is needed to induce CCS, and the LCOE at this P_{GHGE} is 63% more than for Sup PC-V at \$0/t CO_{2eq}.

RC: FTL synthetic fuel plant design in which syngas is recycled to maximize liquid fuel output, along with a small amount of electricity

CO_2 CAPTURE AND STORAGE FOR SYNTHETIC LIQUID TRANSPORTATION FUELS PRODUCTION

Supplemental Material

A major route to synthetic liquid fuels production from coal begins with thermochemical gasification to produce synthesis gas (syngas, which is composed mainly of CO and H_2). After gas cleanup the water-gas-shift reaction is used to adjust the H_2/CO ratio to that needed for synthesis. Acid gases (mainly H_2S and CO_2) are removed from shifted syngas upstream of synthesis—in the case of H_2S to protect the synthesis catalyst from sulfur poisoning and in the case of CO_2 to increase carbon conversion in the synthesis reactor. Typically, acid gases are removed from syngas via absorption in an appropriate physical solvent, and the recovered H_2S is typically reduced to elemental S in a Claus/SCOT (Shell Claus Off-gas Treating process) plant. In the absence of a carbon mitigation policy, the recovered virtually pure CO_2 usually would be vented to the atmosphere.[9] For example, the two Sasol synthetic fuel plants in South Africa vent approximately 20 million tonnes of pure CO_2 annually as a coproduct of generating 140,000 barrels per day of coal liquids (13). Under a carbon-policy constraint this separated CO_2 might instead be compressed (to perhaps 150 bar) and transported by a CO_2 pipeline to a suitable geological storage site.

Various studies have analyzed energy balances, fuel-cycle-wide GHG emissions, and synthetic fuel production costs for systems without and with CCS. One early study investigated the production of the chemicals methanol and dimethyl ether, which can also be used as transportation fuels (20). More recently, several studies have analyzed the production of FTL synthetic fuels (6, 10, 11, 21–26). Key findings of these studies are: (*a*) without CCS, the produced synthetic fuels will be characterized by GHG emission rates for production plus eventual consumption that are approximately double the rates for the equivalent crude oil products; (*b*) CCS at the plant cuts that rate in half, to a level roughly equal to that for the crude oil products displaced; and (*c*) the energy and cost penalties for CCS are quite low.

These general findings can be illustrated by considering calculations carried out by Liu et al. (10) for a large recycle (RC) coal-to-liquids plant designed to maximize liquid fuel production. RC plants can be considered fuel-only plants, although some designs provide a modest net electricity by-product.[10] The CTL-RC systems considered in Reference 10 produce 50,000 barrels per day

[8]To put this P_{GHGE} level into perspective: According to the U.S. Environmental Protection Agency (17), \$50/t CO_{2eq} would be the levelized value of GHG emissions allowances in the United States during the 20-year period 2026–2045 if the Waxman-Markey or the Kerry-Liebermann climate bill or the equivalent were to become U.S. law. For fuel-cycle-wide GHG emissions, this valuation is equivalent to a 55¢/gal tax on gasoline.

[9]But if enhanced oil recovery (EOR) opportunities are available, the CO_2 would typically be compressed and sold for this application because the compression cost is typically less than the EOR market price for compressed CO_2. For example, some 3.0 million t $year^{-1}$ of CO_2 captured at the Great Plains Gasification Plant in Beulah, ND, is transported 300 km to the Weyburn and Midale oil fields in Saskatchewan, Canada, where it is injected into mature oil fields to enable extraction of more oil. The injected CO_2 dissolves in the oil, thereby reducing its viscosity and enabling more oil to flow to the recovery well bore, where it can be extracted (19).

[10]Net electricity is at most a minor by-product of XTL-RC systems. Electricity accounts for ~10% of energy output for the systems described in **Supplemental Table 2** on the basis of calculations in Liu et al. (10). Other analysts (22, 25, 26) have advanced XTL-RC system designs producing zero net electricity.

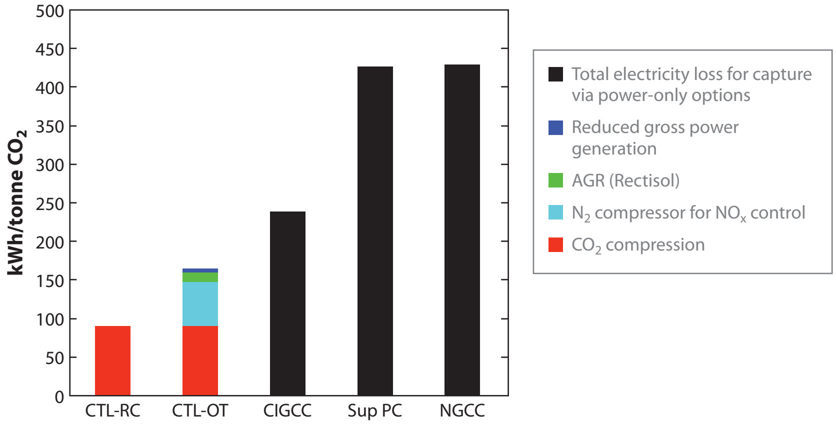

Figure 3

Energy penalty for shifting from the venting (-V) to the CO_2 capture and storage (-CCS) variant of the technologies from **Supplemental Table 2**. Abbreviations: AGR, acid gas removal unit; CIGCC, coal to electricity via integrated gasifier combined cycle power plant; CTL, coal to Fischer-Tropsch liquid synthetic fuels plant; NGCC, natural gas to electricity via combined cycle power plant; OT, once-through; RC, recycle; Sup PC, supercritical pulverized coal power plant.

of FTL synthetic fuels, with GHGI = 1.71 and 0.89 for the -V and -CCS variants, respectively (see **Supplemental Table 2**). The energy penalty for CO_2 capture (consisting only of that for CO_2 compression[11]) in shifting from CTL-RC-V to CTL-RC-CCS is 90 kWh_e/t of captured CO_2, which is only 38% of that for shifting from CIGCC-V to CIGCC-CSS (see **Figure 3**). The minimum P_{GHGE} needed to motivate investment in CO_2 capture, transport, and storage is a modest \$12/t CO_{2eq}, and the levelized cost of fuel (LCOF) at this P_{GHGE} value is only 18% higher than that for CTL-RC-V at P_{GHGE} = \$0/t CO_{2eq} (see **Figure 4**).

CO_2 CAPTURE AND STORAGE FOR BIOMASS ENERGY

A key attribute of biomass is that its carbon content is derived from CO_2 extracted from the atmosphere during photosynthesis. As a result, biomass grown sustainably and converted to useful energy in systems requiring only modest inputs for production and conversion can be nearly carbon neutral. Since the late 1990s considerable analytical attention has been given to extending the role of biomass energy in mitigating climate change by making the carbon balance for biomass energy carbon-negative instead of carbon-neutral via the pursuit of CCS. In these analyses the energy products considered include hydrogen (27, 28),[12] EtOH[13] (29), electricity (30–32), and synthetic liquid fuels (6, 10, 11, 22–24, 32). The strategic implications of realizing the negative GHG emissions benefits of CCS for biomass energy in an overall global carbon mitigation effort have been receiving increasing attention (33–35). These studies argue that, whereas energy portfolios from a broad range of energy technologies are needed to attain low

LCOF: 20-year levelized cost of liquid fuel production, in dollars per gigajoule

XTL: X [X = coal (C), biomass (B), or coal/biomass (CB)] to FTL synthetic fuels

[11] This is because other capture costs are charged to the FTL synthetic fuel production account rather than the C-mitigation account.

[12] The analysis of hydrogen from biomass with CCS in Reference 27 is based on Reference 28.

[13] When ethanol is produced via fermentation, one molecule of CO_2 is released from the fermenter for each molecule of ethanol (C_2H_5OH) produced. This CO_2 is generated as a pure stream so that only CO_2 drying and compression are needed for capture, the costs of which are modest (as in the case of coal-based synthetic fuels).

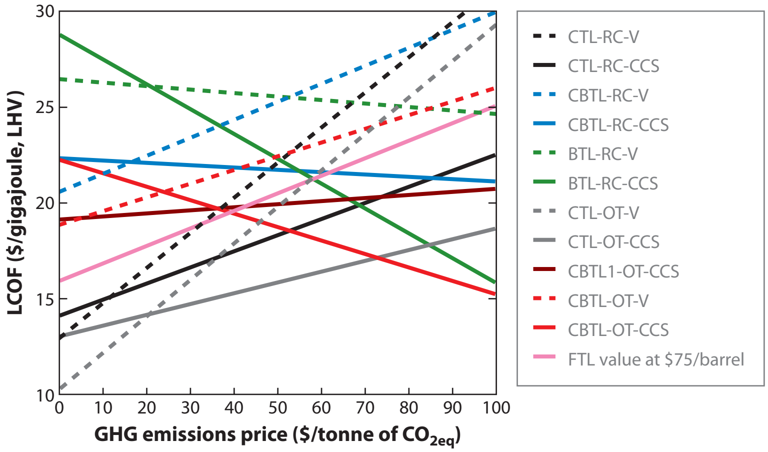

Figure 4

Levelized cost of fuel (LCOF) versus P_{GHGE} for the 11 Fischer-Tropsch liquid (FTL) synthetic fuels plant configurations listed in **Supplemental Table 2**, calculated using the assumptions of **Supplemental Table 1**. The market value of FTL synthetic fuels at a crude oil price of $75/barrel is also shown. The minimum greenhouse gas (GHG) emissions price needed to induce a shift from CTL-RC-V to CTL-RC-CCS is the P_{GHGE} at the crossover point for the LCOFs of these two options (at $12/t CO_{2eq}). Abbreviations: CCS, CO_2 capture and storage; LHV, lower heating value; NGCC, natural gas to electricity via combined cycle power plant; OT, once-through; RC, recycle; V, CO_2 venting; XTL, X [X = coal (C), biomass (B), or coal/biomass (CB)] to FTL synthetic fuels. The 1 in CBTL1-OT-CCS indicates first-generation technology with only 12% biomass in feedstock on an energy basis (compared to 40% biomass for CBTL-OT-V and CBTL-OT-CCS).

atmospheric GHG concentrations, negative emission technologies (e.g., biomass energy with CCS) significantly enhance the possibility of meeting low-concentration targets.

Calculations carried out by Liu et al. (10) for a large CTL-RC-CCS plant and a small BTL-RC-CCS plant (producing 4,500 barrels/day from processing 1 million dry tonnes of biomass/year)[14] illustrate these general findings for the relative economics of coal-to-liquids and biomass-to-liquids plants without and with a strong carbon mitigation policy. The assumed biomass price is 2.7 times the coal price[15] (see **Supplemental Table 1**), and the estimated capital intensities are $98,000 and $163,000 per barrel per day, respectively (see **Supplemental Table 2**). Under these conditions the LCOF for biomass-derived FTL synthetic fuels = 2.0 times that for coal-derived FTL synthetic fuels at P_{GHGE} = $0/t CO_{2eq}, but LCOF values become equal at P_{GHGE} = $69/t CO_{2eq} (see **Figure 4**). This convergence of LCOF values arises because of the sharp upward slope of the LCOF versus P_{GHGE} curve for CTL-RC-CCS (GHGI = +0.89) and the sharp downward slope of the LCOF versus P_{GHGE} curve for BTL-RC-CCS (GHGI = −0.95). Although BTL-RC-CCS never offers the lowest LCOF among the options displayed in **Figure 4** over the indicated $0/t CO_{2eq} to $100/t CO_{2eq} range of P_{GHGE} values, FTL synthetic fuels produced via this option would be competitive with crude oil–derived products for $P_{GHGE} > \$58$/t CO_{2eq} and thus would be a viable synthetic fuel option in biomass-rich but coal-poor regions at such P_{GHGE} values.

[14]The economics of corn stover energy conversion as a function of annual biomass delivery rate was investigated in Reference 24. It was found that if biomass is delivered by truck, (*a*) the economies of scale for energy conversion outweigh the increased cost of delivered biomass over a wide range of delivery rates when truck traffic congestion issues are ignored, but (*b*) traffic congestion concerns are likely to limit practical delivery rates to ∼1 million dry tonnes/year.

[15]This is consistent with findings of a study involving a detailed biomass supply logistics analysis (24).

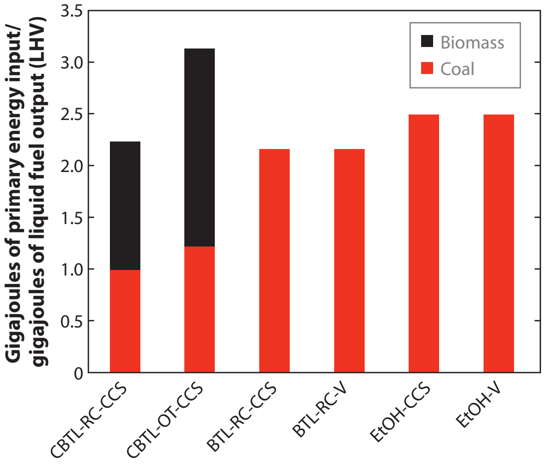

Figure 5

Primary energy inputs of coal and biomass to provide liquid transportation fuels. Calculations for Fischer-Tropsch liquid (FTL) synthetic fuels are from data in **Supplemental Table 2**. Those for cellulosic ethanol (EtOH) are for data from **Supplemental Tables 4** and **5**. In all cases the primary energy input includes input to provide the electricity coproduct. Abbreviations: CCS, CO_2 capture and storage; LHV, lower heating value of a fuel; OT, once-through; RC, recycle; V, CO_2 venting; XTL, X [X = biomass (B) or coal/biomass (CB)] to FTL synthetic fuels.

COPROCESSING BIOMASS AND COAL TO MAKE SYNTHETIC LIQUID TRANSPORTATION FUELS WITH CO_2 CAPTURE AND STORAGE

In recent years several studies have shown that the negative emissions benefit of CCS for biomass energy could be exploited more cost effectively in the making of synthetic fuels with GHG emission rates less than those for crude oil products displaced by coprocessing biomass with coal, exploiting thereby both the economies of scale of coal energy conversion and the typically lower delivered cost of coal compared with biomass (6, 10, 11, 21–24, 36–38).

These studies stress that coprocessing biomass with coal enables a major new role for coal in providing low-carbon synthetic transportation fuels for a carbon-constrained world. Moreover, coprocessing biomass with coal could provide transportation fuels with near-zero GHG emissions using much less lignocellulosic biomass than is required for biofuels by exploiting the negative emissions associated with photosynthetic CO_2 storage. Consider the CBTL-RC-CCS option analyzed in Liu et al. (10), which coprocesses enough biomass (45% on an energy basis) to realize GHGI = 0.029 (see **Supplemental Table 2**).[16] For this system, the amount of biomass required per gigajoule of low-carbon liquid fuel provided is 40% of that needed for making cellulosic EtOH (see **Figure 5**), for which GHGI = 0.17 (see **Supplemental Table 3**).

[16]For this system, 53.7% of the feedstock carbon is stored underground as CO_2, 42.7% is released into the atmosphere as CO_2 (21% in flue gases at the conversion plant and 79% from the ultimate combustion of the FTL synthetic fuels), and 3.5% is stored in landfills as carbon in the char generated via gasification. The carbon released into the atmosphere is more than compensated for by the carbon extracted from the atmosphere during photosynthesis (the 46.7% of the feedstock carbon in biomass). However, other carbon-equivalent GHG emissions upstream and downstream of the plant, equivalent to 5.4% of the feedstock carbon (55% from biomass production and transport, 40% from coal mining and transport, and 5% from downstream distribution of FTL synthetic fuels), lead to a slight positive net carbon-equivalent GHG emission rate for the system is $42.7 - 46.7 + 5.4 = 1.4\%$ of feedstock carbon.

Liu et al. (10) also developed a quantitative analysis of the economic benefits of coprocessing for the CBTL-RC-CCS option, which, as in the BTL-RC-CCS case, is sized to limit the annual biomass input to 1 million dry tonnes per year. For this option the FTL synthetic fuels output capacity is 2.2 times that of the corresponding BTL-RC-CCS plant, and the specific capital cost (dollars per barrel per day) is 15% lower (see **Supplemental Table 2**). At low GHG emissions prices the LCOF for CBTL-RC-CCS is lower than that for BTL-RC-CCS, but for a GHG emissions price that is >\$55/t CO_{2eq}, the BTL-RC-CCS option is less costly. This is a result of the relative flatness of the LCOF versus GHG emissions price curve for CBTL-RC-CCS compared with the steeply declining curve for BTL-RC-CCS (see **Figure 4**).

OT: FTL synthetic fuel plant design in which syngas is passed only "once through" the synthesis reactor; unconverted gas fuels a combined cycle power plant

COPRODUCTION OF SYNTHETIC LIQUID TRANSPORTATION FUELS AND ELECTRICITY WITH CO_2 CAPTURE AND STORAGE

Supplemental Material

The authors of this review have contributed to several publications on the coproduction of synthetic liquid transportation fuels and electricity with CCS (10, 11, 18, 20, 21, 23, 24, 38), but few other articles are available in the literature (25, 26, 39). Moreover, only the authors and their collaborators have explored the strategic importance of coal/biomass coprocessing in such systems. However, some articles published earlier on coproduction did not take into account that CCS opportunities (40, 41) are relevant to understanding the strategic importance of coproduction. Both of these earlier articles and the more recent articles that emphasize CCS highlight two important strategic benefits of coproduction: (*a*) the higher overall energy efficiency compared with producing synthetic fuels and electricity in separate facilities and (*b*) the lower cost of synthetic fuel production compared with systems that make only synthetic fuels or for which electricity is but a minor by-product.

This section, based on Liu et al. (10), discusses these general findings in the context of the five XTL-OT systems listed in **Supplemental Table 2**. In these once-through (OT) systems, the syngas exiting the synthesis reactor is not recycled to increase FTL synthetic fuel output but rather is burned in the combustor of a gas turbine/steam turbine combined cycle power plant to produce electricity as a major coproduct; energy outputs are approximately two-thirds FTL synthetic fuel and one-third electricity. CBTL-OT-CCS (see **Figure 1**) is a focus. In what follows, first a quantitative perspective on the above two general findings is provided for coproduction systems analyzed from the liquid fuel producer's perspective. Subsequently, CBTL-OT-CCS, which coprocesses 40% biomass and realizes thereby GHGI = 0.093 (see **Supplemental Table 2**), is compared with advanced biofuels options for providing low-carbon transportation fuels. Finally, the additional strategic benefits that arise when coproduction systems are analyzed from an electric power generator's perspective are discussed.

Coproduction Systems Evaluated from a Synthetic Fuel Producer's Perspective

Figure 4 presents LCOF versus P_{GHGE} curves for the five XTL-OT and six XTL-RC systems listed in **Supplemental Table 2** calculated under the assumptions of **Supplemental Table 1**. In constructing these curves, a credit against the cost of synthetic fuel production is received for sale of the coproduct electricity. The electricity selling price is assumed to be the average busbar selling price for U.S. grid electricity in 2007 (\$60/MWh_e), augmented by the value of the average GHG emission rate for the U.S. grid in 2007 (for details see **Supplemental Table 1** and discussion in the Analytical Framework section in the **Supplemental Text**).

XTL-OT systems offer less costly FTL synthetic fuel than do XTL-RC systems for the assumed simple electricity pricing model.[17] Notably, over the range of GHG emissions prices considered, CTL-OT-V (GHGI = 1.31) offers the least costly FTL for $P_{GHGE} < \$24/t\ CO_{2eq}$, followed by CTL-OT-CCS (GHGI = 0.70) until $P_{GHGE} = \$73/t\ CO_{2eq}$, above which CBTL-OT-CCS (GHGI = 0.093 with 40% biomass) offers the least costly FTL synthetic fuel. It is notable that, over the entire range of P_{GHGE} values displayed, CTL-OT-CCS can provide less costly FTL synthetic fuel while offering greater carbon mitigation benefits than either CBTL-RC-V (GHGI = 0.96 with 45% biomass) or CBTL-OT-V (GHGI = 0.77 with 40% biomass).

MEGE: marginal electricity generation efficiency for OT FTL synthetic fuel systems

The more favorable economics for XTL-OT systems is partly a consequence of the improved energy efficiency of coproduction systems relative to separate systems for producing electricity and liquid fuels; this efficiency has been reported in various studies (10, 11, 25, 26). A metric used in Liu et al. (10) to quantify this efficiency gain is the marginal electricity generation efficiency (MEGE), the definition of which is adapted from Reference 42:

MEGE = (additional power generated via OT design relative to RC design when both plants are sized to produce the same amount of FTL synthetic fuel)/(additional coal consumed).

Supplemental Table 2 shows that MEGEs for XTL-OT designs are much higher than the efficiencies for new coal power plants—e.g., the lowest MEGE for XTL-OT-CCS is approximately the same as the efficiency of a stand-alone Sup PC-V plant. The high MEGEs arise mainly as a result of the following processes: One, the heat generated as a result of the intense exothermicity of Fischer-Tropsch (FT) synthesis reactions is captured as saturated steam by evaporating water in boiler tubes immersed in the FT slurry bed. If subsequently superheated, this steam can be used to generate power in a steam turbine. Two, in OT designs more than enough high-quality heat is available (in gas turbine exhaust gases) to superheat all saturated steam. Three, for RC designs the available heat comes from burning purge gases, which is adequate to superheat only 60% of the saturated steam generated in synthesis and other upstream exotherms.

A striking feature of the LCOF versus P_{GHGE} curves in **Figure 4** needs explanation: the strong negative slope for the CBTL-OT-CCS curve. One might expect its slope to be slightly positive because its GHGI is slightly positive (0.093; see **Supplemental Table 2**). The slope is instead negative because GHG emission charges enter the LCOF calculation both for the system-wide emissions and for the credit for electricity sales (which is assumed to rise with the average GHG emission rate for the U.S. electric grid), and the latter is greater than the former (see **Supplemental Table 6*a***). Although LCOF values for CBTL-OT-CCS and CBTL-RC-CCS are equal at $P_{GHGE} = \$0/t\ CO_{2eq}$, this growing carbon mitigation credit for the coproduct electricity implies a growing net production cost advantage for CBTL-OT-CCS relative to CBTL-RC-CCS as P_{GHGE} increases (see **Figure 4**).

A relatively high P_{GHGE} ($73/t CO_{2eq}) is needed to make CBTL-OT-CCS the least costly FTL synthetic fuel option (see **Figure 4**). However, the corresponding tough carbon mitigation policy brings with it major liquid transportation fuel supply security benefits as well as large carbon

[17] Because electricity accounts for a large fraction of system output, estimated LCOF values are sensitive to the assumed electricity selling price. Thus, different electricity pricing models might give different results. However, the general finding that XTL-OT options provide less costly FTL synthetic fuels than XTL-RC options is likely to be robust. Consider, for example, that the electricity selling price at $P_{GHGE} = \$73/t\ CO_{2eq}$ (the price at which CBTL-OT CCS becomes the least costly FTL synthetic fuel option among those in **Figure 4**) would have to be reduced 35% from the modeled price, to $69/$MWh_e$, to enable CBTL-RC-CCS and CBTL-OT-CCS to have equal LCOF values at that P_{GHGE}. Furthermore, that electricity price is 35% less than the LCOE for CIGCC-CCS and 5% less than that for CBTL-OT-CCS (the least costly option among those in **Figure 2**) at that P_{GHGE}.

mitigation benefits (the GHGI for CBTL-OT-CCS is 0.093 compared to 0.70 for CTL-OT-CCS). A shift from building a CTL-OT-CCS plant to a CBTL-OT-CCS plant would put at risk to oil price uncertainty only one-third of the capital investment ($1.4 billion instead of $4.6 billion per plant; see **Supplemental Table 2**). Moreover, a P_{GHGE} at this level would enable the FTL synthetic fuels from CBTL-OT-CCS plants to compete against crude oil–derived products at crude oil prices down to $45/barrel. Thus, a tough carbon mitigation policy that favors low-carbon FTL synthetic fuel technologies would simultaneously offer a high degree of protection to investors in these synthetic fuel technologies against the risk of oil price collapse.

Comparing Alternative Options for Providing Low-Carbon Transportation Fuels

It is of interest to understand how the four low-carbon fuel options based on thermochemical conversion (BTL-RC-V, BTL-RC-CCS, CBTL-RC-CCS, CBTL-OT-CCS) compare not only to each other but also with cellulosic EtOH, which has been the main focus of U.S. biofuel development activities. The analysis of cellulosic EtOH presented here is based on findings developed in Reference 6 that are cast in the internally self-consistent analytical framework of this review. That study considered only cellulosic EtOH systems that vent CO_2 (EtOH-V). Here a CCS option (EtOH-CCS) is also included (for details, see the Cellulosic Ethanol Analysis section in the **Supplemental Text**). The most important metrics for these comparisons are relative carbon mitigation benefits, relative biomass utilization benefits, and relative production costs.

Greenhouse gas mitigation metrics. **Supplemental Table 3** lists GHGI and GHGA values for the six low-carbon fuel options compared. A notable feature of these data is that a shift from -V to -CCS leads much less emissions mitigation for cellulosic EtOH than for BTL-RC—e.g., GHGA increases only 24 kg CO_{2eq}/GJ for cellulosic EtOH compared with 109 kg CO_{2eq}/GJ for BTL-RC. The reason is that the CO_2 capture rate (expressed as a percent of the carbon in the biomass feedstock) is much smaller for cellulosic EtOH-CCS (15%) than for BTL-RC-CCS (56%).

Biomass utilization benefits. Given that biomass supplies capable of providing truly low-carbon fuels are likely to be more limited than was thought just a few years ago (2–6), the scarce biomass resource must be used as efficiently as possible in meeting societal goals. **Figure 5** shows that CBTL-OT-CCS requires 49% and 56% as much biomass per gigajoule of liquid transportation fuel as do cellulosic EtOH and BTL-RC options[18], respectively, whereas CBTL-RC-CCS requires 40% and 46% as much, respectively.

Economic analysis. **Figure 6** shows LCOF versus P_{GHGE} curves for the six low-carbon fuel technologies compared, each of which is designed to consume the same amount of biomass

[18]The CBTL-OT-CCS option that coprocesses 40% biomass with coal involves capturing only the naturally concentrated streams of CO_2 from syngas (mild CO_2 capture). An alternative system configuration analyzed in Reference 10, CBTL-OTA-CCS, involves reforming via an autothermal reformer the C_1 to C_4 gas in the syngas downstream of synthesis followed by a water-gas-shift reactor and additional CO_2 capture equipment. This configuration is able to realize a comparable GHGI = 0.086 with only 29% biomass. This alternative system configuration that involves more aggressive CO_2 capture can typically provide less costly synthetic liquid fuels at the same biomass input rate (1 million t year^{-1}) as for CBTL-OT-CCS because of the lower average feedstock price and the scale economies arising from the greater FTL synthetic fuel output capacity. The CBTL-OTA-CCS option requires 36% and 42% as much biomass per gigajoule of liquid transportation fuel as do the EtOH and BTL-RC options, respectively.

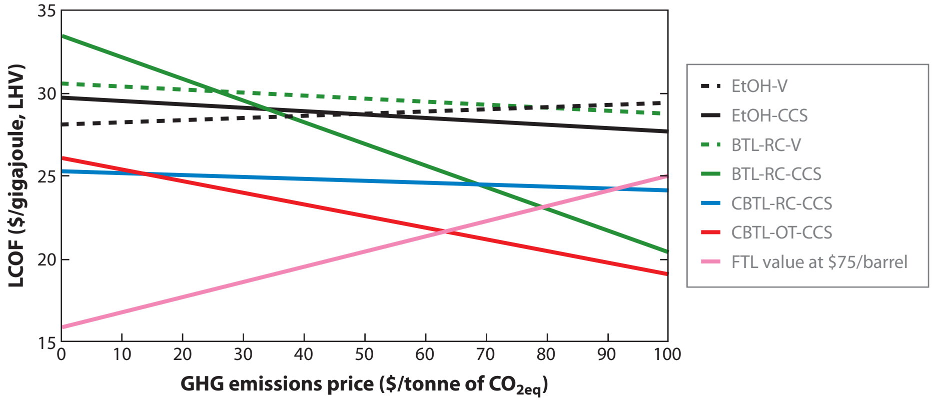

Figure 6

Levelized cost of fuel (LCOF) versus P_{GHGE} for plants listed in **Supplemental Table 3**, calculated for the assumptions of **Supplemental Tables 1, 4, and 5**. Abbreviations: CCS, CO_2 capture and storage; EtOH, ethanol; FTL, Fischer-Tropsch liquid; GHG, greenhouse gas; LHV, lower heating value for a fuel; OT, once-through; RC, recycle; V, CO_2 venting; XTL, X [X = biomass (B) or coal/biomass (CB)] to FTL synthetic fuels. The LCOF of $26 per gigajoule for CBTL-OT-CCS at zero GHG emissions price can alternatively be expressed as $3.1 per gallon of gasoline equivalent.

(0.47 million t/year[19]). This internally self-consistent analysis shows that the least costly option is CBTL-RC-CCS up to $P_{GHGE} = \$13/\text{t } CO_{2eq}$, above which CBTL-OT-CCS is the least costly up to $P_{GHGE} = \$123/\text{t } CO_{2eq}$ (not shown), above which BTL-RC-CCS is the least costly. Cellulosic EtOH is never one of the least costly options even though it is the least capital-intensive (see **Supplemental Table 4**).

Supplemental Material

This analysis shows (see **Figure 6**) that whereas a shift from a -V to a -CCS system configuration leads to a sharply falling LCOF with rising P_{GHGE} for both CBTL-OT and BTL-RC, the economic benefit with increasing P_{GHGE} of shifting from -V to -CCS is modest in the cellulosic EtOH case. This reflects, as noted earlier, the modest fraction of feedstock C stored as CO_2 in the cellulosic EtOH case.

Coproduction Systems Evaluated from a Power Generator's Perspective

A comparison between GHGI and GHGA values for the major competing electric generation options is instructive (see **Figure 7**). With GHGI values ≤0.2, Sup PC-CCS, CIGCC-CCS, NGCC-CCS, and CBTL-OT-CCS are all candidates for helping realize the U.S. goal of reducing GHG emissions 80% by midcentury. **Figure 7** also shows that all four of these options avoid comparable amounts of GHG emissions (in kilograms CO_{2eq} per megawatt hour) via electricity generation. However, the total GHGA for CBTL-OT-CCS is 1.9 times that for CIGCC-CCS because of the displacement of crude oil–derived products with the FTL synthetic fuels coproducts.[20]

In estimating the LCOE for XTL-OT systems from an electricity generator's perspective, Liu et al. (10) assume that FTL synthetic fuel products are sold at the wholesale (refinery-gate) prices

[19]This rate (approximately one-half the rate of the biomass-consuming options for which levelized production costs are shown in **Figure 4**) was chosen because it is the annual biomass input rate assumed for EtOH-V production in Reference 6, the study upon which the present ethanol analysis is based (see the Cellulosic Ethanol Analysis section in the **Supplemental Text**).

[20]Similarly, whereas NGCC-V and CBTL1-OT-CCS have comparable GHGI values (0.51 and 0.50, respectively; see **Supplemental Table 2**), the GHGA for CBTL1-OT-CCS is ~1.9 times as large (see **Figure 7**).

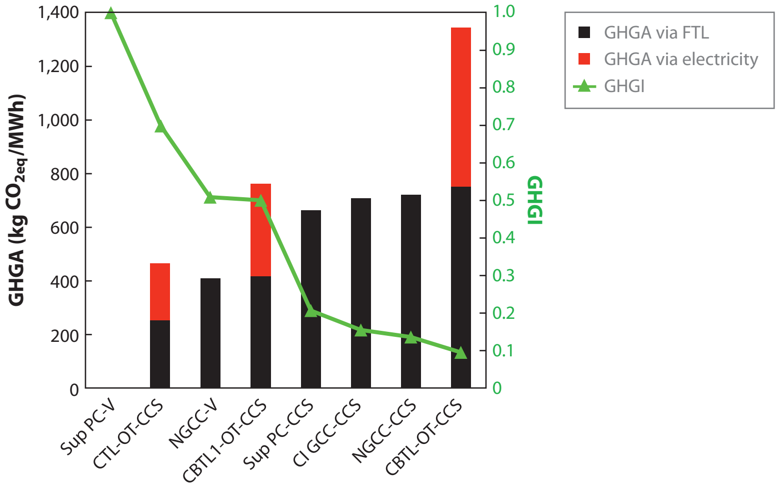

Figure 7

Greenhouse gas emissions index (GHGI) and greenhouse gas avoided (GHGA) values for eight of the power systems listed in **Supplemental Table 2**. [See **Supplemental Table 2** for GHGI and GHGA values for the other three power systems listed there (CIGCC-V, BIGCC-CCS, and CBIGCC-CCS).] Abbreviations: CCS, CO_2 capture and storage; FTL, Fischer-Tropsch liquid; NGCC, natural gas to electricity via combined cycle power plant; OT, once-through; RC, recycle; Sup PC: supercritical pulverized coal; V, CO_2 venting; XIGCC, X [X = coal (C), biomass (B), or coal/biomass (CB)] to electricity via integrated gasifier combined cycle; XTL, X [X = biomass (B) or coal/biomass (CB)] to FTL synthetic fuels. The 1 in CBTL1-OT-CCS indicates first-generation technology with only 12% biomass in the feedstock on an energy basis (compared to 40% biomass for CBTL-OT-CCS).

for the crude oil products displaced (see **Supplemental Table 1** and the Analytical Framework section in the **Supplemental Text**). The LCOE versus P_{GHGE} curves for power generation in **Figure 2** include three of these, CTL-OT-CCS, CBTL1-OT-CCS, and CBTL-OT-CCS (system characteristics are defined in **Supplemental Table 2**[21]), evaluated for a crude oil price of \$75/barrel.

Similar to the LCOF versus P_{GHGE} curve for this option (see **Figure 4**), the CBTL-OT-CCS LCOE curve in **Figure 2** is strongly downward sloping because the GHG emission credit for the crude oil products displaced is much larger than the GHG emissions for the system (see **Supplemental Table 6*b***).

An important result from a comparison of the LCOE versus P_{GHGE} curves in **Figure 2** is that CBTL-OT-CCS is able to compete with Sup PC-V at a lower P_{GHGE} value than CIGCC-CCS (\$38/t CO_{2eq} compared with \$53/t CO_{2eq}), and the LCOE at breakeven is much lower (53% higher instead of 76% higher for Sup PC-V at \$0/t CO_{2eq}). Another way to look at the comparison is that CBTL-OT-CCS offers less costly electricity than CIGCC-CCS (the least costly bituminous coal power with CCS option for new U.S. construction) at P_{GHGE} values >\$20/t CO_{2eq}. A closely related analysis for the United States shows that repowering via CBTL-OT-CCS offers a lower LCOE than a Sup PC-CCS retrofit (the least costly coal power–based option for decarbonizing an existing old, written-off power plant site) for P_{GHGE} values >\$40/t CO_{2eq} (18). Thus, whether

[21]The assumed capacities of the CBTL options evaluated as power generators are 17% less than when the options were evaluated as synthetic fuel producers. See **Supplemental Table 2**.

or not CBTL-OT-CCS is considered for decarbonizing a new or an old coal power plant site, its LCOE is more attractive than that of coal power only with CCS options under a carbon mitigation policy constraint.

Minimum dispatch cost (MDC): in dollars per megawatt hour, the lowest price an electricity generator will bid to sell electricity in economic dispatch competition

Notably, the breakeven P_{GHGE} enabling CBTL-OT-CCS to compete with Sup PC-V in the power market for new plants (see **Figure 2**) is approximately one-half that needed (\$73/t CO_{2eq}) to enable CBTL-OT-CCS to compete with CTL-OT-CCS in the synthetic fuel market (see **Figure 4**).[22] This suggests that a power market would be the more attractive one in which to deploy CBTL-OT-CCS technology. Why the break-even P_{GHGE} value in the power market for new construction is so much lower than that needed to enable CBTL-OT-CCS to become the least costly option for produce FTL synthetic fuels is discussed below.

The low break-even P_{GHGE} values for the power market relates in part to the substantial scale economies for coal-only plants. Coal power plants are typically much smaller than coal synfuel plants when measured in terms of fuel input rates, which makes it hard for inherently small CBTL-OT-CCS plants to compete with large CTL-OT-CCS plants as synfuel providers unless GHG emissions prices are high. However, more than scale economies are involved here. Other relevant considerations that make XTL-OT systems economically attractive at the modest plant scales that are typical of power generation relate to (*a*) the large credit from the sale of FTL synthetic fuel coproducts, (*b*) the low CO_2 capture penalties compared with the electricity produced in stand-alone power plants, and (*c*) the low minimum dispatch cost (MDC) at high oil prices. Of course, the high MEGE of XTL-OT plants also contributes to attractive system economics, but this occurs whether these systems are considered from a fuel producer's or a power generator's perspective.

Supplemental Material

Credit for Fischer-Tropsch synthetic liquid fuel coproducts. The LCOE for CBTL-OT-CCS presented in **Figure 2** is for a crude oil price of \$75/barrel. Most forecasts envision higher oil prices in the future (1, 43; see also **Supplemental Table 1**). For XTL-OT plants providing FTL synthetic fuels at the same scale as CBTL-OT-CCS plants in **Supplemental Table 2**, each \$1/barrel increase (decrease) in the 20-year levelized crude oil price leads to a \$1.1–\$1.4/MWh_e decrease (increase) in the LCOE.

Energy penalty for CO_2 capture. As already noted, the energy penalty (and associated cost penalty) for CO_2 capture is small for XTL-RC-CCS (just the cost of CO_2 compression). For XTL-OT-CCS systems the energy penalty for capture is higher but still much less than for stand-alone power plants. **Figure 3** shows energy penalties for CO_2 capture for CTL-RC and CTL-OT as well as for three stand-alone power plants: CIGCC (precombustion capture), Sup PC (postcombustion capture), and NGCC (postcombustion capture). In each case the energy penalty is for capture relative to the same system with CO_2 vented. The energy penalty for capture is 80% more for CTL-OT than for CTL-RC, but the penalty for CTL-OT is only 70% of that for CIGCC and only 40% of that for Sup PC and NGCC. That the penalty is intermediate between those for CTL-RC and CIGCC technologies is not surprising because, in a sense, CTL-OT is a combination of those technologies.

That the capture energy penalty is greater for CTL-OT than for CTL-RC is entirely because CO_2 is removed from concentrated CO_2 streams downstream as well as upstream of FTL

[22] A downside for synthetic fuel investors of coproduction for power markets is that, at the much lower break-even P_{GHGE} needed to enable CBTL-OT-CCS electricity to compete, there is no investor protection against the risk of oil price collapse: At \$38/t CO_{2eq}, the FTL synthetic fuel produced via CBTL-OT-CCS requires a crude oil price of \$80/barrel to be competitive, compared with \$45/barrel at \$73/t CO_{2eq}.

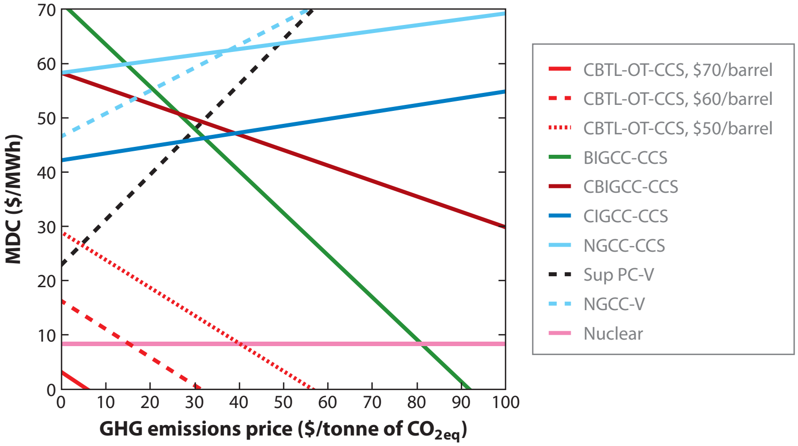

Figure 8

Minimum dispatch cost (MDC) for some of the generation options listed in **Supplemental Table 2** as well as the MDC for nuclear power. Based on Reference 44, the short-run marginal cost for nuclear power = $8.39/MWh = [$6.97/MWh for fuel (nuclear fuel at $0.64 per gigajoule and 33% plant efficiency)] + ($0.42/MWh for variable operation and maintenance) + ($1.00/MWh for the nuclear waste fee). Abbreviations: CBTL, coal/biomass to Fischer-Tropsch liquid synthetic fuels; CCS, CO_2 capture and storage; GHG, greenhouse gas; NGCC, natural gas to electricity via combined cycle power plant; OT, once-through; RC, recycle; Sup PC, supercritical pulverized coal; V, CO_2 venting; XIGCC, X [X = coal (C), biomass (B), or coal/biomass (CB)] to electricity via integrated gasifier combined cycle.

synthetic fuel synthesis. The CO_2 in the downstream syngas is generated in the synthesis reactor because the iron FTL synthetic fuel catalyst has water-gas-shift activity. This CO_2 (accounting for approximately one-half of the total CO_2 captured in this system) would not be removed in the absence of a carbon mitigation policy. A surprising result is that most of the additional energy penalty is for compressing N_2 from the air separation unit for delivery to the gas turbine combustor for NO_x control.[23] For the CTL-OT-V variant, the large CO_2 flow to the gas turbine combustor keeps the adiabatic flame temperature sufficiently low to satisfy NO_x emissions regulations, but once this CO_2 is removed, delivery of N_2 to the gas turbine combustor becomes necessary for NO_x control.

Economic dispatch competition. The electric grid system operator determines the merit order for dispatching plants selling electricity into the grid, typically on an hour-by-hour basis, based on bid prices to sell from the various power-generating units connected to the grid. The minimum price that a power plant operator will be willing to bid is the MDC determined by equating revenues to the system's short run marginal cost (SRMC) for the bidding period. Because coproduction systems generate two revenue streams, the MDC is given by MDC ($ MWh^{-1}) = SRMC ($ MWh^{-1}) – [FTL synthetic fuels revenues (MWh^{-1})], which implies very low MDC values at sufficiently high oil and GHG emission prices. **Figure 8** shows MDC versus P_{GHGE} for CBTL-OT-CCS systems at three crude oil prices and for several stand-alone power systems described in **Supplemental Table 2**. At P_{GHGE} = $0/t CO_{2eq}, the MDC for CBTL-OT-CCS reaches

[23]Water via a saturator is used as a complement to N_2 for NO_x control.

$0/MWh when the crude oil price is $73/barrel. Thus, this must-run baseload[24] coproduction power plant would be able to defend a high capacity factor (CF) in economic dispatch competition and drive down the CFs of competing systems as deployment of these technologies on electric grids increases.

IRRE: internal rate of return on equity

TOWARD AN OPTIMAL CO_2 CAPTURE AND STORAGE STRATEGY FOR BIOMASS ENERGY

In light of growing interest in exploiting the negative GHG emissions benefit of photosynthetic CO_2 storage for biomass energy (33, 34, 35), this subsection addresses the question: What is the optimal CCS technology for biomass energy? The question is addressed from an economic perspective. The LCOF versus P_{GHGE} curves in **Figures 4** and **6** indicate that CBTL-OT-CCS is the least costly low-carbon liquid fuel-producing option, at least up to P_{GHGE} = $100/t CO_{2eq}, but the LCOE versus P_{GHGE} curves in **Figure 2** suggest that, among power options, BIGCC-CCS (for which GHGI = −0.93) would provide less costly electricity than CBTL-OT-CCS at P_{GHGE} values approaching $100/t CO_{2eq}.

To explore further the relative economic merits of alternative biomass energy with CCS systems, internal rate of return on equity (IRRE) calculations were carried out for four options listed in **Supplemental Table 2**: BIGCC-CCS, CBIGCC-CCS (with GHGI = −0.34), BTL-RC-CCS, and CBTL-OT-CCS.[25] CBIGCC-CCS is included in this comparison because its biomass input percentage (39%) is similar to that of CBTL-OT-CCS, for which the economics seem to be very attractive.

IRRE calculations make it feasible to compare in a self-consistent manner the economics of electricity generation systems, synthetic fuel production systems, and coproduction systems. The IRRE calculations were carried out under the assumption that each system consumes 1 million t of biomass annually. The IRRE was calculated as a function of both P_{GHGE} (over the range $0/t CO_{2eq} to $100/t CO_{2eq}) and crude oil price ($50, $75, and $100/barrel). **Figure 9** presents a set of IRRE calculations for which design CFs are assumed (CF = 85% for power and CF = 90% for systems that produce synthetic fuels; see **Supplemental Table 1**). The figure shows that CBIGCC-CCS is never the most profitable option. The IRRE for CBTL-OT-CCS is greater than the IRRE for BTL-RC-CCS up to $P_{\mathrm{GHGE}} \approx$ $100/t CO_{2eq} at all oil prices considered. The IRRE for BIGCC-CCS is greater than the IRRE for CBTL-OT-CCS at high P_{GHGE} values, but the P_{GHGE} crossover point increases sharply with crude oil price. However, the MDC for BIGCC-CCS will tend to be much higher than that for CBTL-OT-CCS (see **Figure 8**); thus, if much of the latter generating capacity is on the grid, the actual CF for BIGCC-CCS may be much less than the design CF.

Figure 10 shows IRRE values for these four systems when instead CF = 60% for BIGCC-CCS and CBIGCC-CCS. In this case BIGCC-CCS fares well at high P_{GHGE} values only for relatively low oil prices.

This analysis suggests strongly that for decades to come, systems that coproduce electricity and synthetic transportation fuels from coal and biomass with CCS will be the economically preferred

[24]All the XTL-OT systems considered in Liu et al. (10) and listed in **Supplemental Table 2** were designed as must-run baseload units. Alternatively, XTL-OT systems might be designed (with additional capital investment) to provide extra electric capacity so as to make more electricity and less liquid fuel during times of peak electricity demand when electricity selling prices are high, while keeping gasifier throughput constant. Such more complicated designs are likely to be more profitable, but as discussed below, even the simpler must-run baseload designs described here are likely to be quite profitable.

[25]The IRRE is not included for EtOH-CCS because it is relatively small; for example, it is less than 10% per year over the entire $0/t CO_{2eq} to $100/t CO_{2eq} range of P_{GHGE} when the crude oil price is $75/barrel.

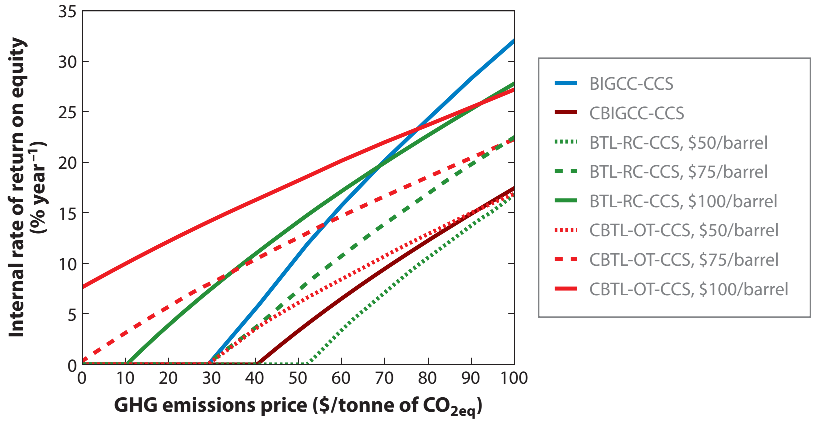

Figure 9

Internal rate of return on equity (IRRE) values for four low–greenhouse gas (GHG)-emitting energy technologies listed in **Supplemental Table 2**, assuming design capacity factor (CF) values (85% for power and 90% for plants making synthetic fuels). IRRE for BIGCC-CCS > IRRE for CBTL-OT-CCS for P_{GHGE} > \$35/t CO_{2eq} at \$50/barrel crude oil, P_{GHGE} > \$55/t CO_{2eq} at \$75/barrel, and P_{GHGE} > \$75/t CO_{2eq} at \$100/barrel. However, it would be difficult for BIGCC-CCS to defend its design CF in economic dispatch competition if much CBTL-OT-CCS capacity was on the grid (see **Figure 8**). Abbreviations: CCS, CO_2 capture and storage; OT, once-through; RC, recycle; XIGCC, X [X = biomass (B) or coal/biomass (CB)] to electricity via integrated gasifier combined cycle; XTL, X [X = biomass (B) or coal/biomass (CB)] to Fischer-Tropsch synthetic liquid fuels.

Supplemental Material

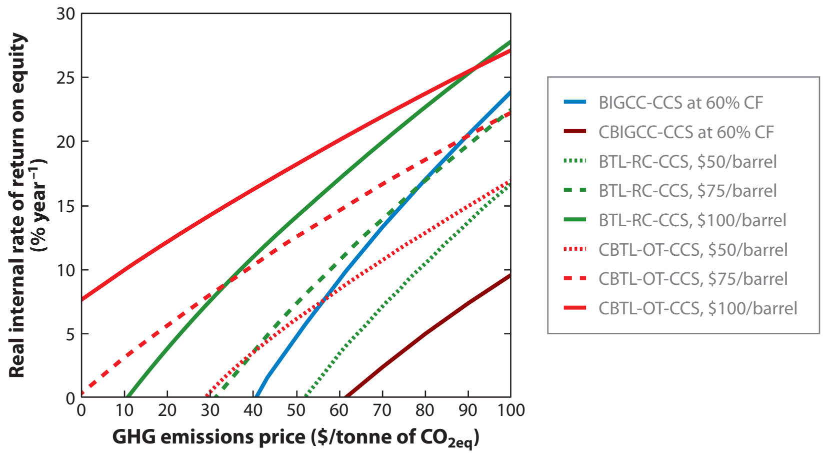

Figure 10

Internal rate of return on equity (IRRE) values if the capacity factor (CF) = 60% for power-only options. For these IRRE calculations it is assumed that economic dispatch competition has reduced the CF for the BIGCC-CCS and CBIGCC-CCS power systems from the 85% design value to 60%. Abbreviations: CCS, CO_2 capture and storage; GHG, greenhouse gas; OT, once-through; RC, recycle; XIGCC, X [X = biomass (B) or coal/biomass (CB)] to electricity via integrated gasifier combined cycle; XTL, X [X = biomass (B) or coal/biomass (CB)] to Fischer-Tropsch synthetic liquid fuels.

approach for exploiting CCS for photosynthetic CO_2 in biomass-rich regions that have access to adequate coal supplies.

A TECHNOLOGICAL INNOVATION THEORETICAL CONTEXT FOR COAL AND BIOMASS TO FUELS AND POWER

Worldwide, gasification for coal power markets has been pursued primarily in the form of CIGCC technology. The technology has not caught on although it had an auspicious beginning. A 120-MW_e demonstration project involving multiple industrial collaborators operated between 1984 and 1989 at Cool Water in southern California. It was one of the most successful energy demonstration projects of all time, as it was carried out on schedule and under budget, and it met its technical demonstration goals (45). It was followed by the launch of four government-supported commercial-scale CIGCC projects during 1993–1997 (two in the United States and two in Europe) with a total installed capacity of ~1 GW_e. As of 2007, four additional CIGCC projects had come on line worldwide to add an additional ~1 GW_e of capacity (46).[26] A few CIGCC-CCS projects are planned because the technology offers lower capital cost and LCOE than Sup PC-CCS does (see **Supplemental Table 2** and **Figure 2**), but there is no rush to embrace CIGCC-CCS to meet the carbon challenge for coal power.

A fundamental tenet of technological innovation theory is that the market is most likely to adopt new products if they are irresistible, that is, if they offer multiple benefits that incumbent technologies cannot possibly provide (47). But CIGCC technology has not proven to be irresistible. It has not taken off because, during the period in which the technology was introduced, continuing marginal improvements to the incumbent technology (steam turbine power) made it difficult for CIGCC to compete; Sup PC-V technology is more energy efficient, and its LCOE is lower than that of CIGCC-V technology (see **Supplemental Table 2** and **Figure 2**). Moreover, much of the world's coal power community is hoping that advances in postcombustion capture or oxy-combustion capture[27] will make it feasible for them to stick with the coal boiler technology with which they are comfortable rather than to pursue the strange CIGCC-CCS chemical process technology.

But gasification could be irresistible if the sweet spots of the flexibility it offers in providing useful energy are exploited. Gasification can be used not only to make power (or combined heat and power) from a variety of feedstocks (XIGCC technologies) but also to make chemicals, synthetic fuels (XTL-RC technologies), synthetic fuels plus electricity (XTL-OT technologies), or other combinations of products from this list.

The analysis in this review shows that the coal and biomass to fuels and electricity concept represents one potential sweet spot for gasification that seems to offer irresistible economic as well as environmental and energy security benefits in a world where oil prices are likely to be comparable with or greater than at present and where serious carbon mitigation policies will eventually be enacted in many parts of the world. To be sure, this approach, which requires a fundamental reorganization of the energy system, faces formidable institutional challenges (as discussed in the next section), but if the prospective benefits are truly irresistible, ways will be found (with appropriate public policy support) to overcome these obstacles.

[26]For perspective, worldwide coal-generating capacity was 1,897 GW_e in 2007 and is projected to grow to 2,705 GW_e in 2030 under the IEA's Reference Scenario (1).

[27]Oxy-combustion is an advanced capture technology (13, 16) that involves burning fuel in oxygen instead of air so that the main products of combustion are CO_2 and water vapor largely undiluted with nitrogen from air. With this technology simply condensing water out of this combustion product stream recovers CO_2 for storage.

CHALLENGES AND PUBLIC POLICY ISSUES

With the exception of uncertainties with regard to CCS as a major carbon mitigation option, the main obstacles to deployment of technologies that coprocess coal and lignocellulosic biomass via thermochemical gasification to coproduce electricity and transportation fuels with CCS are institutional rather than technical or economic, especially when these systems are evaluated as alternatives to CCS options for fossil fuel power plants. Although the coproduction systems that have been the focus of this review, which are designed as must-run baseload plants, are not especially complex technologically, they are institutionally complex because they involve the simultaneous marketing of three radically different commodity products (liquid fuels, electricity, and CO_2). A commodity market for CO_2 does not yet exist except for CO_2-enhanced oil recovery (EOR) operations (mainly at a few locations in the United States). Moreover, the production and marketing of electricity and liquid fuels are carried out today by electric utilities and oil companies that are culturally quite different in their management of technology risks and market risks. It is unclear what entities would own and operate coproduction plants and market their products. Deployment agents quite different from today's typical electric utilities and oil companies might be needed. New public policies are needed to overcome these institutional hurdles, e.g., policies that encourage the development of suitable new business models.

Routine deployment of these technologies will not be feasible until CCS is established as a viable major carbon mitigation option. The global community has only modest experience with CCS. The current rate of CO_2 storage in the five fully integrated CCS projects now operating worldwide is approximately 5 million t year^{-1}.[28] At the 2008 G8 Hokkaido Toyako Summit in Japan, the G8 committed to launching 20 commercial-scale CCS demonstration projects globally by 2010 to support technology development and cost reduction to enable broad deployment of CCS after 2020. In February 2010 President Obama issued a Presidential Memorandum calling for five to ten commercial-scale CCS demonstration projects to be up and running in the United States by 2016.

It is unclear if these G8 and U.S. goals, which must be regarded as but modest first steps in addressing the daunting global CCS challenge, will be met. The IEA (14) has estimated that to be on track toward realization of the goal of storing more than 10 billion t year^{-1} in some 3,400 projects by 2050, the global community should be aiming to store some 300 million t year^{-1} in approximately 100 projects worldwide by 2020. This implies that approximately 10 plants should be brought on line annually during this decade, and some 85 new storage projects per year are needed on average during 2010–2050.

In addition, commercial-scale demonstrations of coproduction systems that coprocess biomass and coal with CCS are needed during this decade. First-generation technologies are likely to coprocess modest quantities of biomass, e.g., CBTL1-OT-CCS, which coprocesses only 12% biomass but would be able to realize GHGI = 0.5 (approximately the same as NGCC-V; see **Supplemental Table 2**). Moreover, first-generation technologies might involve not parallel gasifiers (as envisioned in **Figure 1**) but rather cogasification of coal and biomass in a coal gasifier that can accommodate coprocessing a modest amount of biomass. The commercial Buggenum XIGCC facility in the Netherlands, which was built originally for coal but has been cogasifying

[28]Three of the five projects [Sleipner and Snøhvit (Norway) and In Salah (Algeria)] involve extracting CO_2 from natural gas streams for which the CO_2 level is too high to meet the specifications required for pipeline natural gas; the CO_2 is stripped, collected, and stored securely in underground geological formations. Two of the projects use CO_2 for EOR while simultaneously storing the CO_2. One of these recovers CO_2 from a natural gas processing plant in Wyoming and sends it via pipeline to the Rangely oil field in Colorado, where it is used for EOR. The other (the Weyburn-Midale project discussed in footnote 9) uses CO_2 captured at the Great Plains Gasification plant for CO_2 EOR in the Weyburn and Midale oil fields.

coal and some biomass since 2006 (48), is likely to serve as a model for cogasification systems built during the next decade.

The low CO_2 capture costs for these coproduction systems make them good candidates for being some of the 100 commercial-scale integrated CCS projects that the IEA argues should be deployed worldwide by 2020 (14). This is especially true given that governments will probably have to pay for a large fraction of the incremental CCS costs for these projects during the period when GHG emissions prices are not likely to be high enough in many parts of the world to enable the private sector to shoulder these incremental costs.

Gasifiers large enough to be deployed for biomass only in large commercial-scale CBTL and BTL systems are not yet available. R&D and commercial demonstration policies aimed at evolving such gasifiers are needed in parallel with a policy to promote commercial-scale demonstrations of coal/biomass cogasification for the first generation of coproduction technologies that would coprocess modest amounts of biomass.

Presently, lignocellulosic biomass is used for energy at only modest levels throughout the world. In parallel with policies that would launch in the market first-generation coproduction technologies that coprocess modest amounts of biomass, new public policies are needed to promote the development of lignocellulosic biomass supply logistics infrastructures for biomass. Furthermore, new regulations are needed to ensure that these biomass supplies are produced renewably in ways that minimize adverse impacts.

High priority should be given to providing financial support for carrying out assessments, region by region, worldwide, of two resources of strategic importance to the energy coproduction strategy that is the focus of this review:

- lignocellulosic renewable biomass supplies[29] that prospectively can be provided without conflicting with food production and without incurring large adverse land-use impacts; and
- secure geological CO_2 storage capacity (on a reservoir-by-reservoir basis) not only for fossil fuel–rich regions but also for biomass-rich but fossil fuel–poor regions where, to date, little attention has been given to prospects for geological storage of CO_2.

R&D on all aspects of the proposed energy strategy would be helpful, but most of the emphasis in public policy should be on deployment and learning-by-doing in light of the attractive economics offered by Nth plants (see discussion in **Supplemental Text** on the distinction between costs for Nth plants and for first-of-a-kind plants) based on commercial and near-commercial technological components.

Supplemental Material

Finally, the energy strategy that has been the focus of this review makes no economic sense in the absence of a carbon mitigation policy. However, this energy strategy could be implemented in power markets with a less-stringent carbon mitigation policy than is required with decarbonization strategies for stand-alone power plants.

CONCLUSION

The strategy of coprocessing coal and biomass via gasification to coproduce electricity and transportation fuels with CCS reviewed here offers these systemic benefits:

- It would enable decarbonization of coal power at lower P_{GHGE} and LCOE values at current or higher oil prices than is feasible for any coal-based power-only decarbonization strategy

[29]These assessments will ideally take the form of supply curves for cost of delivered biomass versus cumulative quantity of delivered biomass.

while simultaneously providing electricity from coal with ultralow emissions of conventional air pollutants and mercury.

- It would enable a major new role for coal in providing ultraclean low-carbon synthetic transportation fuels that would be highly competitive with biofuels derived from lignocellulosic biomass.
- At the P_{GHGE} values needed to make low-GHG-emitting XTL-OT-CCS plants cost competitive (in either power or synthetic fuel markets), investors would be exposed to much less risk of oil price collapse (because such plants are necessarily small and thus require much less capital investment) than would investors in large synthetic fuel plants that have much larger carbon footprints.
- In the presence of a strong carbon mitigation policy, investors in low-GHG-emitting XTL-OT-CCS plants would be highly protected against the risk of oil price collapse.

Although the strategy is innovative, the first plants (involving the coprocessing of ~10% biomass on an energy basis) could be deployed in this decade in systems using only technological components that are fully proven or near-commercial.

Aside from the need to resolve uncertainties with regard to CCS as a major carbon mitigation option, which is key to the widespread deployment of the these technologies, the main obstacles to deployment are institutional rather than technological or economic in a world of high oil prices and a societal commitment to address the carbon challenge. New public policies are needed both at the national level and via bilateral/multilateral collaboration. The latter are especially important to avoid or minimize the spillovers that would occur if only national policies were enacted.

DISCLOSURE STATEMENT

The authors are not aware of any affiliations, memberships, funding, or financial holdings that might be perceived as affecting the objectivity of this review.

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