Presented at the Sixth International Conference on Greenhouse Gas Control Technologies,
October 1 – October 4, Kyoto, Japan. Publication pending by Elsevier Science.

BIOMASS ENERGY WITH GEOLOGICAL SEQUESTRATION OF CO_2: TWO FOR THE PRICE OF ONE?

James S. Rhodes and David W. Keith

Department of Engineering and Public Policy, Carnegie Mellon University,
Pittsburgh, PA, 15213, USA

ABSTRACT

We explore the technical feasibility and economic implications of combining biomass energy systems with carbon capture and sequestration technology, resulting in energy products with negative net atmospheric carbon emissions. This represents an efficient strategy for biomass-based carbon mitigation and a mechanism for offsetting emissions sources elsewhere in the economy, fundamentally changing the role of biomass in achieving deep emissions reductions. We develop crude engineering-economic models of two potential systems based on IGCC and bio-ethanol technologies. The results of these models provide a basis for comparison with more conventional mitigation technologies. This comparison suggests that, depending on biomass feedstock costs, biomass technologies with carbon capture may be competitive with other mitigation options in the electric sector. Regardless of this intra-sector attractiveness, however, emissions offsets generated by biomass energy systems with CO_2 sequestration are likely to be more cost effective than many direct mitigation options outside the electric sector.

INTRODUCTION

Biomass has long been investigated both as a (nearly) CO_2 neutral substitute for fossil fuels and as a means of offsetting industrial emissions by sequestering carbon in terrestrial ecosystems [1]. More recently the possibility of using fossil fuels without carbon emissions by CO_2 capture and sequestration (CCS) has emerged as an important alternative for mitigating atmospheric emissions. Combining CCS technologies with biomass energy systems (biomass-CCS) would generate useful energy products and effectively remove CO_2 from the natural carbon cycle for geologic timescales.

The primary focus of CCS technology development has been to provide a mechanism to substantially reduce atmospheric carbon emissions from the current mix of fossil energy resources. This strategy's attractiveness stems from its compatibility with existing energy infrastructures. In addition, however, CCS could be integrated with biomass energy systems. In this application, atmospheric carbon – fixed in biomass during production – is captured and sequestered away from the atmosphere, resulting in a net carbon sink or negative net emissions.

While it remains largely unexplored, several factors make biomass-CCS an attractive option within a portfolio of carbon mitigation strategies: (i) The net reduction in atmospheric CO_2 from biomass-CCS systems provides a mechanism to offset emissions anywhere in the economy; (ii) the system would

efficiently utilize limited land and water resources relative to other biomass strategies [2]; and, (iii) all of the components necessary for biomass-CCS either currently exist at large scales or are in the late stages of development for such applications.

We developed a crude bottom-up engineering-economic model of one feasible, though non-optimal, biomass integrated gasification combined cycle system with CCS (BIGCC-CCS). The model is based on pre-existing component cost estimates and ASPEN simulation results [3,4,5]. In addition, we modeled capture and sequestration of CO_2 fermentation off-gases (Ethanol-CCS) in a pre-existing engineering-economic model of bio-ethanol production [6]. To compare the economics of these systems with other mitigation options, we developed a top-down energy cost model for electricity and liquid fuels as a function of carbon price.

BIOMASS-CCS MODELS

The BIGCC-CCS design includes biomass gasification, syngas conditioning, carbon capture, and a gas turbine combined cycle power system. As the model is intended to illustrate near term potential rather than the current state-of-the-art, technology cost and performance assumptions are based on an 'n^{th}' plant design and a 10-year time horizon. The model is developed from previously published ASPEN simulation results and associated component cost estimates; our efforts are restricted to integration of the component technologies. The results represent reasonable estimates of cost and performance for one feasible design. A number of design alternatives and alternative component technologies exist, but no optimization has been performed.

The Battelle Columbus Laboratory / Future Energy Resource Company (BCL/FERCO) technology was selected for the biomass gasifier [3,4]. It uses steam-blown gasification and provides heat for gasification by burning residual char in a separate reaction vessel. Circulating sand provides heat transfer between the char combustion and gasification reaction vessels. Steam-blown gasification with indirect heating avoids dilution of the syngas by atmospheric nitrogen, simplifying carbon separation relative to air-blown gasification technologies. However, roughly 30% of the fuel carbon is released from the char combustor, reducing net carbon capture efficiency. This compromise might be avoided by adapting oxygen-blown gasification technologies currently used for coal. Beyond its ability to produce undiluted syngas, the BCL/FERCO system appears to have several design benefits including relatively high throughput, high energy efficiency, and low capital costs. While the technology is still in development for large-scale applications, it should be available within the time horizon of this analysis.

The gasification and syngas conditioning components of the BIGCC-CCS model are based on a study of hydrogen production by Margaret Mann [3]. Modifications to the original design include: substitution of a steam dryer assembly for the rotary dryer, elimination of the PSA system, redefinition of the heat source for steam reforming, and addition of supplemental power generation from available process steam. A more recent study of the BCL/FERCO technology by Weyerhaeuser provided cost and performance parameters for the steam dryer assembly and an update for syngas composition and production rates [4]. Note that there are several alternatives to the design choices made in the current model. For example, steam reforming of higher hydrocarbons could be eliminated to reduce electricity costs (due to lower capital costs and higher net plant efficiency). However, this would reduce the carbon capture efficiency of the system, as the higher hydrocarbons pass through the system and are burned in the gas turbine. Such trade-offs between cost of electricity and net carbon emissions illustrate how carbon capture technologies will likely be determined by complex economic optimizations rather than binary choices of available technologies.

The carbon capture component of the model was incorporated without modification from the study by Doctor et al [5]. The core technology of this system is a wet CO_2 scrubber with a glycol (Selexol^{TM}) solvent. Solvent regeneration – and CO_2 de-sorption – occurs via depressurization into a series of flash tanks. The resulting CO_2 streams are compressed for pipeline transport and the regenerated solvent is compressed, refrigerated and recycled to the scrubber. The process streams for integration between syngas conditioning and CO_2 capture have nearly identical compositions. An additional compressor is incorporated

to account for pressure differences, and a higher heat rate is assumed for the pre-scrubber heat exchanger. Finally, the gasifier and syngas conditioning systems are scaled up by a factor of two over the systems in the original study to equalize flow rate with that of the carbon capture system.

The gas turbine combined cycle system is based on GE's H-class technology with performance modifications reflecting the hydrogen rich fuel gas. While this technology is currently only available at 400 MW_e scale, we assume that a comparable technology will be available at 100 MW_e scale within the time horizon of this analysis [7]. The fuel gas composition is modeled by adjusting the conditioned syngas composition to reflect fractional changes in the CO_2 capture system's process flow components. We include fuel gas humidification of 0.6 kg steam per kg fuel and assume net power plant conversion efficiency of 60% (LHV) [7,8].

Our economic modeling efforts include converting the component cost estimates in the original literature to year 2000 dollars, developing capital cost estimates for additional equipment, scaling the biomass gasifier and syngas conditioning costs up by a factor of 2, and estimating annual O&M costs. The installed cost of the gas turbine combined cycle system is assumed to be 550 $/kW. Transport and geological sequestration of pressurized CO_2 is assumed to cost $10/tonne CO_2 at the plant gate.

Bio-ethanol with CCS

We model a bio-ethanol production system with CCS based on the work by Wooley et al. [6]. The only significant modification is to incorporate compression of CO_2 off-gases from the fermentation tanks. This stream represents 11% of the feedstock carbon in the baseline model. However, the content of this stream is assumed to scale with ethanol production, so more efficient processing will lead to higher carbon capture rates. We assume 13.3% carbon capture will be achievable in ten years based on published efficiency projections in the literature [6]. The net conversion efficiency of the system is not penalized for the energy requirement for CO_2 compression because the baseline facility generates surplus electricity. Instead, the economic credit from electricity sales over the fence are reduced, though the resulting net increase in O&M costs are not significant at the level of this model. Finally, we assume a 15% energy efficiency benefit for bio-ethanol production due to potential advantages for ethanol use in spark ignition engines relative to gasoline [9]. The cost and performance results for baseline and capture models of both systems are detailed in Table 1.

TABLE 1

Techno-economic results for baseline and CCS models

Parameter	BIGCC	BIGCC-CCS	Ethanol	Ethanol-CCS
Total Capacity (bone dry tons / day)	1,814	1,814	2,000	2,000
Total output (MWe | 10^6 L/yr)	141 MW_e	108 MW_e	235 ML/yr	235 ML/yr
Net Conversion efficiency (HHV)	34%	26%	40%	40%
Carbon capture rate (% input carbon)	-	53%	-	13.3%
Total Capital Requirement ($M)	$87	$200	$234	$236
Non-Fuel O&M ($/kW-yr | $M/yr) [+]	$81	$113	$7.3	$7.3
Product Cost (c/kWh | $/L)*	5.87	8.88	0.35 ($1.33/gal)	0.36 ($1.36/gal)
Carbon Mitigation Cost ($/tC)*	$99	$128	$333	$243

[+] Not including cost of sequestration.

*Based on the energy cost model parameters defined below.

Top-down energy cost model

We develop an energy cost model to evaluate these biomass-CCS technologies within the context of other mitigation technologies. The model evaluates the producer cost of electricity and liquid fuels for various technologies as a function of carbon price. Such a price may result from a carbon tax, a tradable permit system, or some hybrid. Mitigation costs are defined by the carbon prices where energy costs from the mitigation technologies equal those from a specific baseline technology. Pulverized coal and gasoline are defined as the baselines for the electric and transportation fuel sectors, respectively. The model includes coal and natural gas technologies with and without CCS as well as more conventional biomass IGCC and bio-ethanol technologies. Results from a single deterministic case are illustrated in Figure 1, given the fuel and technology parameters defined in Table 2 and below.

Capital costs are amortized over twenty years at 10% interest. Annual O&M is defined as a fraction of total capital cost, 5% for electric sector fossil technologies, 6% for electric sector biomass technologies, and 2.75% for bio-ethanol technologies. Annual utilization is assumed to be 0.65 and 0.95 in the electric and liquid fuels sectors, respectively. Fuel costs are fixed at 1.0, 3.7, 2.7, and 7 dollars per gigajoule for coal, natural gas, biomass and gasoline, respectively. 'PC' represents pulverized coal technology, 'CIGCC' represents coal integrated gasification combined cycle technology, and 'NGCC' represents natural gas combined cycle technology. '-CCS' indicates inclusion of carbon capture technology.

TABLE 2

Energy cost model technology parameters

Technology	Capital cost ($/kW)	Efficiency (HHV)	Carbon Capture Rate (% input Carbon)
PC	1,200	40%	-
CIGCC-CCS	1,560	35%	98%
NGCC	500	55%	-
NGCC-CCS	1,020	47%	98%
BIGCC	1,212	34%	-
BIGCC-CCS	1,845	26%	53%
BioEthanol	1,270	40%	-
BioEthanol-CCS	1,280	40%	13%

RESULTS AND DISCUSSION

According to the energy cost model results in Figure 1, natural gas without CCS dominates electric sector technologies until carbon prices near 200 dollars per ton carbon ($/tC) (note: the curve for NGCC-CCS coincides with that for CIGCC-CCS). While this is an important result, there are several reasons why the electric sector may not experience wholesale conversion to natural gas with carbon prices up to 200 $/tC. Natural gas prices may rise with increasing demand, improving the competitiveness of alternate technologies. Natural gas price uncertainty and volatility may result in technology diversification even if long-term average natural gas prices don't rise. And finally, alternate technologies may enter due to carbon emission targets below that achievable with non-CCS natural gas technology alone.

While the cost of electricity from our model of BIGCC-CCS in Figure 1 is high under zero carbon price, the system's negative net emissions cause the cost of electricity to decrease with increasing carbon price. This could result from a carbon tax credit or the sale of internally generated emissions offsets, depending on the regulatory framework. The result is that the mitigation cost associated with this model is generally competitive with other electric sector technologies (128 $/tC compared to 87 $/tC for CIGCC-CCS). As

carbon prices rise, BIGCC-CCS becomes the least cost electricity producer in the sector. In the extreme case, with high enough carbon prices, electricity could be generated as a free byproduct of sequestering CO_2.

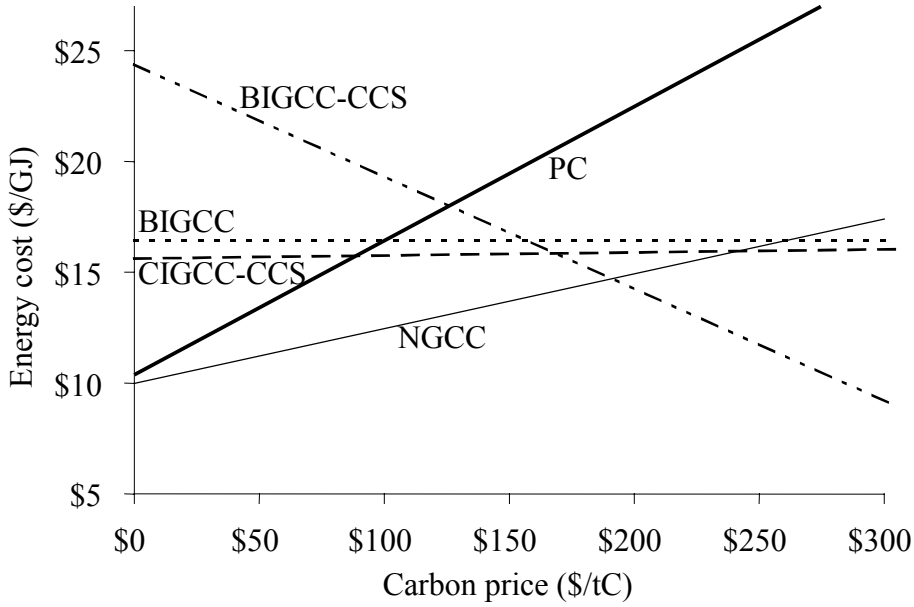

Figure 1: Electric sector energy costs as a function of carbon price

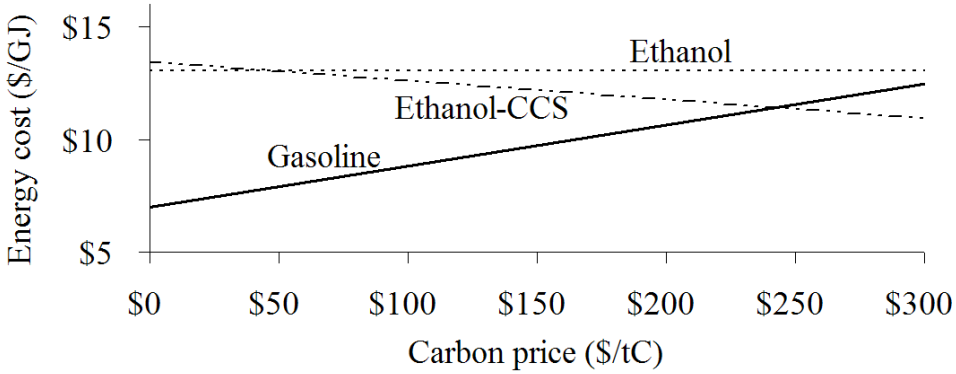

Figure 2: Liquid fuel sector energy costs as a function of carbon price

While mitigation costs in the transportation fuels sector, illustrated in Figure 2, are much higher overall than in the electric sector, adding CCS substantially reduces the mitigation cost associated with bio-ethanol. This is particularly relevant given the number of existing bio-ethanol facilities with CO_2 vents that could easily be captured and redirected for geological sequestration. These facilities could quickly benefit from any carbon price system that recognizes the potential for negative emissions.

Potentially more important than the competitive mitigation costs of either biomass-CCS system within their own sectors is their potential to generate emissions offsets for other sectors at the same costs. Top-down economic analyses suggest marginal mitigation costs rising above 1,000 $/TC to stabilize atmospheric CO_2 concentrations at an equivalent doubling of pre-industrial levels [10]. By crediting negative emissions from biomass-CCS technologies to sources that are expensive to mitigate directly, mitigation costs could be capped across the economy, given sufficient biomass supply. While the dollar value of this mitigation cost cap cannot be determined with confidence—because it will scale with the cost of biomass—the ability to offset emissions anywhere in the economy fundamentally changes the potential role of biomass for achieving deep carbon emissions reductions.

ACKNOWLEDGEMENTS

We gratefully acknowledge thoughtful comments on this work from Michael Griffin, Gregg Marland, Allen Robinson, and Edward Rubin.
This research was made possible through support from the Center for Integrated Study of the Human Dimensions of Global Change. This Center has been created through a cooperative agreement between the National Science Foundation (SBR-9521914) and Carnegie Mellon University, and has been generously supported by additional grants from the Electric Power Research Institute, the ExxonMobil Corporation, and the American Petroleum Institute.

REFERENCES

1. Kheshgi, H.S., Price, R.C. and Marland, G. (2000). *The Potential of Biomass Fuels in the Context of Global Climate Change: Focus on Transportation Fuels*. Annual Review of Energy and the Environment. 25: pp. 199-244.
2. Keith, D.W., (2001). Sinks, Energy Crops, and Land Use: Coherent Climate Policy Demands an Integrated Analysis of Biomass. Climatic Change. 49: p. 1-10.
3. Mann, M.K. (1995). *Technical and Economic Assessment of Producing Hydrogen by Reforming Syngas from the Battelle Indirectly Heated Biomass Gasifier*. National Renewable Energy Laboratory.
4. Weyerhaeuser, (2000). *Biomass Gasification Combined Cycle DE-FC36-96GO10173*. United States Department of Energy.
5. Doctor, R.D., J.C. Molburg and Thimmapuam, P.R., (1996). *KRW Oxygen-Blown Gasification Combined Cycle: Carbon Dioxide Recovery, Transport, and Disposal*. United States Department of Energy.
6. Wooley, R., Ruth, M., Sheehan, J., Ibsen, K., Majdeski, H., and Galvez, A. (1999). *Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Future Scenarios*. National Renewable Energy Laboratory.
7. Matta, R.K., Mercer, G.D., and Tuthill, R.S. (2000). *Power systems for the 21st Century – "H" Gas Turbine Combined-Cycles*. GE Power Systems. Schenectady, NY.
8. Audus, H., and Jackson, A.J.B. (2001). *CO2 Abatement by the Combustion of H2-Rich Fuels in Gas Turbines*. In: Proceedings of the 5th International Conference on Greenhouse Gas Control Technologies. Williams, D., et al. (Eds). CSIRO Publishing: Collingwood, Australia.
9. Wymann, C.E. (1996). *Handbook on Bioethanol: Production and Utilization*. Taylor and Francis: Washington, D.C.
10. Metz, B., et al., (Eds). Climate Change 2001: Mitigation: Contribution of Working Group III to the Third Assessment Report of the IPCC. 2001, Cambridge University Press: Cambridge, UK.

T&B 0.185
Sides 0.608