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Carbon mitigation with biomass: An engineering,

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**Carbon mitigation with biomass: An engineering, economic and policy assessment
of opportunities and implications**

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To my wife, children, parents, and grandparents

Executive summary

Industrial bio-energy systems provide diverse opportunities for abating anthropogenic greenhouse gas (“GHG”) emissions and for advancing other important policy objectives. The confluence of potential contributions to important social, economic, and environmental policy objectives with very real challenges to deployment creates rich opportunities for study. In particular, the analyses developed in this thesis aim to increase understanding of how industrial bio-energy may be applied to abate GHG emissions in prospective energy markets, the relative merits of alternate bio-energy systems, the extent to which public support for developing such systems is justified, and the public policy instruments that may be capable of providing such support.

This objective is advanced through analysis of specific industrial bio-energy technologies, in the form of bottom-up engineering-economic analyses, to determine their economic performance relative to other mitigation options. These bottom-up analyses are used to inform parameter definitions in two higher-level stochastic models that explicitly account for uncertainty in key model parameters, including capital costs, operating and maintenance costs, and fuel costs. One of these models is used to develop supply curves for electricity generation and carbon mitigation from biomass-coal cofire in the U.S. The other is used to characterize the performance of multiple bio-energy systems in the context of a competitive market for low-carbon energy products.

The results indicate that industrial bio-energy systems are capable of making a variety of potentially important contributions under scenarios that value anthropogenic GHG emissions. In the near term, cofire of available biomass in existing coal fired power plants has the potential to provide substantial emissions reductions at reasonable costs. Carbon prices between \$30 and \$70 per ton carbon could induce reductions in U.S. carbon emissions by 100 to 225 megatons carbon (“MtC”), equivalent to roughly 3% of U.S. GHG emissions.

In the medium or longer term, integration of carbon capture and storage technologies with advanced bio-energy conversion technologies (“biomass-CCS”), in both liquid fuels production and electric sector applications, will likely be feasible. These systems are capable of generating useful energy products with negative net atmospheric carbon emissions at carbon prices between \$100 and \$200 per tC. Negative emissions from biomass-CCS could be applied to offset emissions sources that are difficult or expensive to abate directly. Such indirect mitigation may prove cost competitive and provide important flexibility in achieving stabilization of atmospheric GHG concentrations at desirable levels.

With increasing deployments, alternate bio-energy systems will eventually compete for limited biomass resources and inputs to agricultural production—particularly land. In this context, resource allocation decisions will likely turn on the relative economic performance of alternate bio-energy systems in their respective energy markets. The relatively large uncertainty in forecasts of energy futures confounds reliable prediction of economically efficient uses for available biomass resources.

High oil prices or large valuation of energy security benefits will likely enable bio-fuels production to dominate electric-sector options. In contrast, low oil prices and low valuation of energy security benefits will likely enable electric-sector applications to dominate. In the latter scenario, indirect mitigation of transportation-sector emissions via emissions offsets from electric-sector biomass-CCS could prove more efficient than direct fuel substitution with biofuels, both economically and in terms of the transportation-sector mitigation of available biomass resources [tC tbiomass⁻¹].

The policy environment surrounding industrial bio-energy development is systematically examined. Specifically, the policy objectives that may be advanced with bio-energy and the challenges constraining deployment are examined to understand the extent to which public policy support is justified to accelerate development. Policy frameworks and specific policy instruments that have been proposed or enacted to support industrial bio-energy are evaluated to understand their current and potential future roles in shaping bio-energy development.

This analysis indicates that deployment of industrial bio-energy systems to advance specified policy objectives has been compromised by inefficient and inconsistent public policies. Amending existing policies could substantially accelerate bio-energy deployment. More generally, public policies that set even prices across the economy for advancing targeted policy objectives should be developed. Industrial bio-energy systems can be expected to compete favorably in the context of such policies, including those valuing deep reductions in anthropogenic GHG emissions.

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Chapter 1

Introduction

Stabilizing atmospheric carbon dioxide (“CO₂”) concentrations at a level sufficient to avoid dangerous interference with natural systems – the agreed goal of the Framework Convention on Climate Change – represents a fundamental challenge to industrial society. A wide set of technologies and energy resources have been considered and will likely be required to achieve this objective. Among these, biomass has long been investigated both as a (nearly) CO₂ neutral substitute for fossil fuels and as a means of offsetting emissions by sequestering carbon in terrestrial ecosystems [1]. The relatively recent development of carbon capture and storage (“CCS”) technologies, conceived as a means toward fossil fuel use without atmospheric CO₂ emissions, provides a new suite of tools by which biomass may contribute to managing anthropogenic carbon emissions and atmospheric concentrations. However, realizing these potential contributions will require overcoming substantial barriers to development; moreover, because biomass resource use intersects with policy objectives across the economy, widespread deployment will require balancing diverse risks and potential benefits associated with industrial bio-energy systems.

It is within this context that this thesis aims to improve the understanding of (i) the potential roles for industrial bio-energy within prospective energy markets, (ii) the relative merits of alternate roles for industrial bio-energy, (iii) the extent to which public support is justified to support these roles, and (iv) the mechanisms through which such

public support may be extended. The primary vehicle employed to advance this understanding is a series of engineering and economic models designed to characterize the performance of and potential contributions from specific bio-energy systems. These modeling efforts are augmented by analysis of the policy environment surrounding industrial bio-energy as well as the policy frameworks and instruments that could enable specific policy objectives to be advanced with bio-energy.

This introductory chapter is divided into two sections. Section 1.1 provides background information on bio-energy and some of the rationale for its consideration in the context of the climate problem. Section 1.2 provides an explanation of the analytical approach developed throughout the balance of this thesis.

1.1. Background

Biomass energy, or bio-energy, is the stored solar energy in un-fossilized organic material, including standing timber, energy crops, forestry and agricultural residues, various waste streams. Historically, the relative contribution of bio-energy has tended to decline with industrialization. For example, biomass was the only primary energy resource on record in the United States until around 1850, and it dominated the U.S. energy supply until 1885 [2]. Fossil fuels were increasingly substituted for biomass with industrialization, expansion of rail networks, and decreasing biomass feedstock availability. Beyond logistical issues of supply, which may have accelerated fuel

substitution in certain regions, the relative convenience of fossil fuels for industrial applications (e.g., from higher energy densities) may have provided a more fundamental driver for this pattern of primary energy resource substitution, globally [3].

An inverse relation between bio-energy utilization and industrialization can also be observed in the modern geographic distribution of primary energy utilization. Tracking of global trends is confounded by inconsistent collection and reporting of “traditional use” (i.e., for home heating and cooking applications) and of “non-marketed” (i.e., individually collected) bio-energy resources; however, the International Energy Agency provides several relevant estimates [4]. Specifically, while biomass is currently estimated to provide approximately 11% of world primary energy, it is estimated to provide only 2-3% of primary energy in developed nations (i.e., OECD member states) compared to 20-30% in nations with economies in transition, and up to 98% in nations with developing economies [4]. The intuitive appeal of this trend is bolstered by the dominance of “traditional use” of biomass resources where bio-energy utilization is greatest; however, several notable exceptions exist. For example, one quarter of primary energy in Finland is from wood fuels and peat [5]. Such counter examples suggest that bio-energy utilization patterns depend on a broad set of factors, including the relative availability of biomass and fossil fuels.

More important than current or historic utilization patterns is the compatibility of bio-energy with modern industrial energy systems. Biomass is commonly used for conventional heat and power applications in industries where feedstock is available at

low or negative costs, as in pulp and paper mills. High-starch feedstock is used to produce bio-ethanol at industrial scale [6]. Modern coal boilers can be modified to use a blend of biomass and coal (see Chapter 2). Moreover, advanced technologies can produce a variety of finished energy products from biomass, including electricity and solid, liquid, or gaseous fuels (see Chapter 3). Unlike other renewable and carbon-neutral primary energy resources, such as wind, solar, and nuclear, the energy conversion technologies and finished products to which biomass can be converted are generally similar to those associated with conventional fossil fuels. As a result, industrial bio-energy development can effectively leverage technology and infrastructure underlying modern and advanced fossil energy systems.

The mechanism enabling industrial bio-energy systems to contribute toward abating anthropogenic greenhouse gas (“GHG”) emissions has long been recognized. To the extent harvested biomass is replanted, the CO₂ emitted from biomass (or biofuel) combustion is balanced by CO₂ fixed from the atmosphere during biomass production via photosynthesis. This “closed loop” bio-energy carbon cycle implies that such systems can represent a (nearly) carbon-neutral substitute for fossil fuels—ignoring the generally small fossil emissions from biomass cultivation, harvest, and transport, as discussed below [7]. More recently it has been recognized that integrating CCS with bio-energy systems could enable atmospheric carbon (fixed through photosynthesis) to be captured (in bio-energy conversion) and sequestered from the atmosphere for geologic timescales [8-11]. As a result, such integrated systems could produce useful energy products with

negative net atmospheric carbon emissions, which could be used to offset positive emissions elsewhere in the economy.

As noted, this discussion ignores emissions from fossil inputs to biomass production, transport, and processing. The quantity of these inputs depends on the type of biomass and the feedstock supply chain. Ethanol from corn, for example, has relatively high fossil inputs, to the extent that the net energy content of corn ethanol has been seriously debated [12]. In contrast, ligno-cellulosic biomass energy systems (e.g., from wood or herbaceous energy crops) can require relatively low fossil inputs, equivalent to between 2 and 8% of energy output [7, 13]. From a life-cycle perspective, additional fossil emissions evolve during power plant construction and decommissioning [14].

Despite these identifiable sources of fossil emissions, the carbon balance of biomass energy systems are not fully resolved due, in part, to the potential for carbon accumulation in soils supporting biomass production [14]. Soil carbon accumulation rates are not well understood and tend to be site specific, but even relatively modest assumptions regarding accumulation rates can make bio-energy systems carbon neutral or negative on a life cycle basis [14]. Resolution of these life cycle issues is beyond the scope of the analyses developed in this thesis, and the simplifying assumption that ligno-cellulosic biomass can be delivered on a carbon neutral basis is adopted throughout.

Increased industrial bio-energy utilization has been proposed as a means to advance a variety of policy objectives beyond anthropogenic climate change. Biomass production

for energy purposes may be able to advance rural economic development objectives by diversifying agricultural production away from currently subsidized conventional commodities [15, 16]. The global distribution of attractive areas for biomass production—particularly the fact that it is generally uncorrelated with that of fossil energy reserves (especially oil)—may enable bio-energy development to advance energy security objectives, through increased geographic diversity of primary energy supply. The ability to replant harvested biomass implies that bio-energy can advance sustainability objectives, through increased use of renewable energy resources. Finally, biomass (and biofuels) combustion products generally contain fewer industrial air pollutants than those from more conventional fossil fuels. As a result, bio-energy deployment has also been proposed to advance certain air quality objectives [17].

The limited deployment of industrial bio-energy systems, in spite of these various potential benefits, reflects substantial challenges to deployment (See Sections 2.2 and 4.2). Feedstock supply systems are confounded by the geographic and temporal distributions of production as well as by certain fuel characteristics (e.g., bulk density). Mature bio-energy conversion technologies are confounded by their relatively small scales of deployment, which are typically limited by the quantity of locally-available biomass feedstock. This has important implications for capital cost and conversion efficiency, as discussed in Section 4.2.1. Advanced technologies are confounded by uncertainty in their technological and economic performance as well as by outstanding research and development requirements to support industrial scale deployment. Ultimately, industrial bio-energy deployment is limited by its financial performance

relative to more conventional alternatives, beyond relatively limited niche applications (e.g., those with low-cost, locally-available biomass resources).

A variety of public policy instruments have been developed to enable industrial bio-energy systems to overcome the various challenges to deployment so that they can be effectively employed to advance specific policy objectives. The extent to which these policies are justified is an issue that is worth examining; however, the fact that they have not been more successful in promoting bio-energy may suggest that they are insufficient, incoherent, or poorly implemented (see Sections 4.3 and 4.4.). Alternatively (or additionally), it may reflect the substantial uncertainty surrounding key aspects of industrial bio-energy development. While uncertainty is generally inherent to new technologies and to the energy sector (where, for example, forecasts of primary energy prices are notoriously unreliable), deployment of industrial bio-energy appears to be particularly confounded, in this regard. More so than other primary energy resources, biomass supply assessments can be uncertain in both quantity and price, due to *inter alia* complex interactions across the economy (e.g., with food supply systems), and this genuine uncertainty is often confounded by issues of temporal or regional variability [15, 18].

Despite these very real challenges, the outlook for industrial bio-energy appears to be improving. In 1978, the World Energy Conference predicted a relatively flat percentage contribution to world primary energy supply from renewable energy resources (including biomass) concluding that, “The practice of cropping wood for direct use as fuel . . . will

undoubtedly remain an important energy source in certain regions. However, its relative importance on the world scene seems bound to diminish.” [19]. In contrast, the International Energy Agency’s 2004 reference case projection indicates that while the percentage contribution of biomass to world primary energy consumption will decrease gradually (as a result of decreasing traditional use of non-marketed resources), the percentage contribution of industrial bio-energy to electricity and power markets will double by 2030 [4]. This evolving outlook for industrial bio-energy may reflect an increasing appreciation for the potential contributions from biomass—and renewable energy systems more generally—toward important policy objectives.

1.2. Analytical approach

The confluence of potential contributions to important social, economic, and environmental policy objectives with very real challenges to deployment creates rich opportunities for study. In particular, the analyses developed in this thesis aim to better understand how industrial bio-energy may be applied to abating GHG emissions in prospective energy markets, the relative merits of alternate bio-energy systems, the extent to which public support for developing such systems is justified, and the public policy instruments that may be capable of providing such support. This objective is advanced through analysis of specific industrial bio-energy technologies in Chapters 2 and 3. This is followed in Chapter 4 with analysis of broader economic and policy issues affecting industrial bio-energy development. Finally, Chapter 5 integrates the analysis developed

in the earlier chapters to develop overarching conclusions and specific policy recommendations. Particular care is taken throughout this analysis to identify and appropriately account for uncertainty and variability, and while the primary focus is on climate benefits, potential contributions toward a wider set of policy objectives are explicitly considered to develop a more comprehensive understanding of the issues and potential roles of industrial bio-energy.

In particular, Chapter 2 provides analysis of biomass cofire with coal in existing coal fired power plants as a near term option for substantially expanding bio-energy deployment with associated reductions in anthropogenic CO₂ emissions. This analysis is initially developed with a plant level engineering-economic model that evaluates the expected costs for biomass electricity from cofire in terms of cost of electricity and pollutant mitigation costs. Coal-specific and plant-specific model parameters are set at values typical of facilities in the U.S. so that variability in these parameters is not confused with uncertainty. Model parameters that are genuinely uncertain, including capital costs, operating costs, and biomass feedstock parameters, are characterized with probability distribution functions in Monte Carlo simulations. To better understand the implications of the resulting cost projections, the plant-level economic model is integrated with estimates for biomass supply and coal consumption for electricity generation in the U.S. to develop national supply curves for biomass electricity and pollutant mitigation with cofire. Uncertain parameters from the plant-level model are carried through to the national model and regional variability is captured by computing scales of deployment and cost estimates at the state level with subsequent aggregation to

the national scale. The resulting national supply curves are relevant both as a projection of potential mitigation by the world's single largest GHG emitter and as a prototypical example of what could be achieved in increasingly global analyses.

Chapter 3 provides analysis of longer term opportunities for biomass-based GHG mitigation with particular focus on opportunities for integrating CCS with advanced bio-energy conversion technologies to generate negative net GHG emissions. The fundamental economic implications and technological pathways to such integrated systems are discussed and several bottom-up engineering-economic models are developed. The first of these models, which describes a biomass integrated gasification combined cycle system ("BIGCC") for electricity generation, is developed from subsystem component technology characterizations and design studies in the literature. Subsequent models, which describe various biofuels production systems, are developed by adapting results from published design studies to enable limited subsystem modifications to facilitate CCS integration without reconstructing models for the balance of plant described in the original design studies. Consistent with published analyses of similar scope, including those on which the current analysis is based, explicit characterization of model uncertainty is limited to capital allocations for contingencies in construction.

In addition, a stochastic energy cost model is developed to evaluate the relative economic performance of the biomass-based mitigation options characterized by the bottom-up engineering-economic modeling developed throughout Chapters 2 and 3. The objective

of this model is to better understand the potential scope of contributions from these bio-energy systems within a competitive environment for low-carbon energy products.

Uncertainties in capital costs, operating costs, and fuel costs are explicitly characterized with probability distribution functions in Monte Carlo simulation.

Chapter 4 provides analysis of the economic and policy issues affecting industrial bio-energy systems. This analysis includes: (i) characterization and evaluation of prominent potential benefits and policy objectives that bio-energy has been proposed to advance; (ii) dominant challenges to bio-energy development and deployment; (iii) policy frameworks through which public support may be extended to advance industrial bio-energy deployment; and (iv) specific policy instruments that have been enacted or proposed in the U.S. to support industrial bio-energy.

Conclusions drawn from the analyses developed in Chapters 2, 3, and 4 are developed and discussed in Chapter 5. More than re-stating results from the previous chapters, a more holistic perspective is taken to integrate the earlier results into a more general set of conclusions. The thesis concludes with specific policy recommendations that reflect the general conclusions, quantitative analyses, and inherent risks discussed throughout this thesis.

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Chapter 1

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Chapter 2

Near-term opportunities from biomass coal cofire

Large-scale deployment of biomass energy systems faces significant hurdles, including those associated with fuel supply, fuel characteristics, conversion efficiency, technological maturity, capital costs, and the delivered cost of energy products, as discussed in Chapter 1. However, cofire of biomass with coal in existing coal-fired power plants may sidestep many of these issues and as such could represent an important pathway toward expanding biomass energy capacity in the near term. The economics, technological maturity, and fuel flexibility of cofire make it attractive relative to most dedicated biomass systems—though financial incentives are required for cofire to be broadly competitive with conventional power systems, making cofire a strong option for proximate bio-energy deployment. Such deployment could provide significant contributions within a portfolio of carbon mitigation strategies and develop technical and fuel market experience to support future deployment of advanced dedicated biomass technologies.

Section 2.1 provides background information on biomass-coal cofire. In Section 2.2, a simple model is developed to compute electricity and pollutant mitigation costs with explicit accounting for uncertainty and variability in a wide range of parameters such as fuel costs, fuel properties, capital costs, and operating costs. The model is applied in Section 2.2 to understand the economics of cofire at the plant level. In Section 2.3, the model is integrated with biomass supply and coal consumption data to develop national

U.S. supply curves for cofire electricity and carbon mitigation. Section 2.4 provides a discussion of the results and implications of these modeling exercises.

2.1. Background

Cofire systems replace a fraction of the coal used in conventional coal-fired power plants with biomass—typically 2-20% on an energy basis. Retrofits to support biomass cofire in existing facilities can be accomplished by developing new biomass fuel handling and storage systems and modifying existing fuel feeding and burner systems. Typically little or no modification is required to downstream systems—including boilers, heat exchangers, generators, and pollution control systems. As a result, cofire can gain substantial leverage from installed generating capacity, with several potential economic benefits.

Capital costs are low for cofire retrofits, typically ranging from 50 to 150 dollars per kilowatt biomass capacity (“\$/kW_{bio}”), depending on the extent of modifications to feeding systems and burner configurations [1]. These costs can be compared with more than 1,000 \$/kW_{bio} for dedicated biomass systems [2].

Simplified siting and permitting requirements, combined with lower construction requirements for retrofits rather than new construction, translate into a relatively short time horizon for deployment of cofire retrofits—typically 1 to 2 years.

Bio-energy conversion in large-scale coal facilities enables relatively efficient biomass utilization. Modern dedicated biomass facilities typically have end-to-end conversion efficiencies of 16 to 25% on a higher heating value basis (“HHV”) compared with 33 to 38% typical of existing coal facilities [1, 3, 4]. This difference generally stems from the relatively small scale of biomass facilities, often limited by biomass supply issues, which makes high-technology systems, like those deployed at coal-fired plants, uneconomical [4]. This results in systems with lower operating steam temperatures and pressures, and ultimately lower plant efficiencies. The often high moisture content of biomass fuels yields a further efficiency penalty, as discussed below. Even so, the potential effect of bio-energy conversion in existing coal facilities is to nearly double the electricity potential of biomass resources and to halve biomass fuel costs on an energy output basis relative to modern dedicated biomass facilities. The magnitude of this efficiency benefit may decrease over time with development of advanced dedicated biomass systems; however, large-scale deployment of such technologies generally requires further research and development [5].

Cofire can largely address the cyclical and somewhat inconsistent nature of biomass fuel availability by appropriate management of the coal-biomass blend ratio. The implications of variable biomass feed rates on plant operations remain somewhat uncertain and may depend on the details of specific retrofits; for example, retrofits with biomass-specific feeding systems and modified burner configurations may be more sensitive than those in which biomass is co-fed with coal through existing systems.

However, at least in principle, the ability to use biomass fuel resources on an as-available basis enables cofire to address annual variability in biomass supply.

Further, cofire appears less sensitive to certain biomass fuel characteristics that can pose challenges for advanced dedicated biomass systems. For example, gasification systems can suffer bed agglomeration problems from the often high and variable alkali, potassium, and chlorine levels in biomass fuels, which are less problematic in cofire applications.

The potential advantages discussed thus far represent benefits for bio-energy relative to dedicated biomass conversion facilities; however, coal-fired power plants can also benefit from specific environmental advantages of biomass cofire. Emissions of sulfur oxides (“SO_x”) are generally reduced as biomass fuels typically contain little sulfur [6, 7]. SO_x reductions are often greater than would be expected from fuel substitution alone because coal sulfur can react with alkali and alkaline species in biomass to form sulfates that can be collected in particulate control systems [8, 9]. It is also widely held that cofiring can reduce emissions of nitrogen oxides (“NO_x”), though the underlying mechanisms are complex and not well understood. Most cofire demonstrations report modest NO_x reductions [8, 10-12], though a few report no change [9, 13]. Importantly, as power plant emissions of both SO_x and NO_x have firm shadow prices in the form of emissions permit costs, accounting for these emissions reductions can lower the effective cost of biomass electricity.

It must be noted that, along with these various benefits, there are costs associated with coupling biomass energy deployment with existing coal capacity. First, there are logistical issues stemming from the transportation challenges inherent to biomass fuels, as discussed in Chapter 1. Specifically, only biomass available within relatively close proximity—maybe 50 miles—of existing coal plants can be economically cofired [14, 15]. This co-location requirement will likely yield stranded biomass resources where there is insufficient local coal capacity and under-utilized cofire potential where there is insufficient locally available biomass. The implications of this limitation are explored further below. However, as U.S. electricity generation from coal currently exceeds that from biomass by almost two orders of magnitude, even relatively minor incorporation of cofire will notably increase electricity production from biomass [16].

In addition to these practical constraints, biomass cofire may face political and institutional barriers in the United States. For example, cofire has been systematically excluded—both explicitly and implicitly—from federally funded mechanisms supporting renewable energy development, as discussed in Chapter 4 [17]. This may stem from desires to promote high-technology solutions, such as wind or solar, or from practical considerations regarding the scale of potential deployment—and associated program cost expectations—if cofire were included (see Chapter 4). Alternatively, cofire’s exclusion may stem from desires to prevent coal-fired generators from taking advantage of environmental incentives. Systematic analysis of the relative import of these potential factors underlying cofire’s exclusion to date are beyond the scope of this analysis; however, it appears that longer-term view may be required in which cofire primarily

represents an early, evolutionary step within a larger vision of biomass and renewable energy development.

Cofire is based on relatively mature technologies, and numerous demonstrations have been performed using commercial coal-fired utility boilers in both the United States and Europe to evaluate the technical feasibility of biomass-coal cofiring [8, 10, 11, 13, 18-22]. These demonstrations provide a wealth of information that spans the range of major coal combustion technologies (stoker-, pulverized- and cyclone-fired systems), important fuel types (wood, straw, switchgrass, and a variety of coals), feeding configurations (biomass premixed with coal and separate feed), and cofiring levels (1 – 40% biomass on an energy basis). The results indicate that there are no major technical obstacles to deploying cofire: cofiring can either benefit or hinder power plant operations, but the problems appear manageable with judicious choices of fuels and operating conditions. Moreover, the results suggest little uncertainty exists regarding cofire operations, performance, or economics given known power plant and fuel-specific parameters, though substantial variability is possible across plants, depending on these parameters.

Despite cofire's various advantages relative to modern dedicated biomass technologies—including increased energy efficiency, reduced costs, and lower uncertainty relative to advanced biomass technologies—the high cost of biomass fuel remains a problem.

Cofiring is generally cost-competitive only in niche applications where locally available low-cost biomass displaces high-cost coal [1, 23, 24]. However, cofire of available biomass residues—including for example, agricultural and mill residues or waste from pre-

commercial timber thinnings—could provide advantages in terms of costs and other parameters relevant to near-term deployment relative to dedicated energy crops. First, by dint of their current availability, these resources could support cofire deployment in the very near-term and rapid expansion of bio-energy utilization where they exist—reducing challenges associated with concurrent development of biomass production and utilization capacity. Second, residues embody low financial risk: available quantities are generally knowable and could be secured with costs defined before retro-fit financing is committed. Finally, as alluded to above, residues and waste streams are expected to be less expensive than dedicated energy crops [14].

From a climate change perspective, cofire—particularly of (limited) residue streams—may be viewed by some as an incomplete and unsatisfying option: stabilization of atmospheric CO₂ levels will require very deep reductions in anthropogenic emissions, much more than what is possible from proximate residue cofiring opportunities. It is true that cofire does not represent a “silver bullet” for carbon mitigation in the electric sector; however, this fact should not be viewed as disadvantage. Cofire of biomass residues may be viewed as a niche application for bio-energy and low-carbon electricity. Such niches are important in developing any new technology, particularly in the context of the climate problem where a “silver bullet” is unlikely, even in the long term. In this context, cofire appears to be a logical near-term approach as it displaces coal, which is the most carbon-intensive fossil fuel. Moreover, emissions pathways for long-term stabilization of atmospheric GHG concentrations at desirable levels do not generally project rapid near-term decarbonization of the economy [25]. The near-term reductions required to meet these

stabilization pathways could therefore be derived from many relatively small cuts across the economy [26], including cofire of proximately available biomass residues. Finally, the technical experience and biomass fuel market development possible from near-term deployment may prove valuable to future development and deployment of advanced dedicated biomass systems.

Several scenarios exist in which cofire could plausibly evolve to provide substantially deeper emissions reductions. First, introduction of energy crops could significantly increase cofire penetration. Second, from a technical perspective, the biomass-to-coal energy ratio in cofire systems could be increased well beyond the 20% maximum generally considered for near-term deployments; higher ratios could permit a strategy in which some coal-fired generation is retired, while the remainder uses a gradually increasing fraction of biomass energy. Finally, if CO₂ capture and storage (“CCS”) technologies are widely deployed [27, 28], then coal-based systems with CCS may well become the base-load generating technology of choice, particularly if natural gas prices rise above about 3.5 \$/GJ [29]. Cofiring biomass in coal plants with CCS can achieve electricity generation with zero net CO₂ emissions as captured biomass carbon offsets coal carbon emissions from incomplete capture. Increasing the biomass-to-coal blend ratio could yield negative net emissions, which could offset emissions elsewhere in the economy [30, 31].

2.2. Plant level modeling

To understand the economics of cofire for electricity generation and emissions reductions, a simple model is developed to compute electricity and pollutant mitigation costs with explicit accounting for uncertainty and variability in a wide range of parameters such as fuel costs, fuel properties, capital costs, and operating costs. As biomass cost is generally the most uncertain model parameter, the model is applied in this section to evaluate plant-level electricity and mitigation costs as a function of biomass cost.

2.2.1. Technical discussion

Numerous demonstrations and technical evaluations of cofiring have been conducted over the past decade, as mentioned above. The details of these efforts are important, particularly in the context of specific retrofit opportunities. However, many of these details are less relevant in the context of the generalized economic modeling described here. Those technical issues with specific impact upon the current modeling exercises are briefly discussed below; for more detailed technical information see recent reviews in the literature [10, 32, 33].

Cofiring can create fuel-feeding challenges because coal processing and delivery systems are not designed to handle fibrous biomass fuels with their associated low energy density

and high moisture content. Two alternatives exist for feeding biomass fuels in cofire applications, with distinct implications for capital costs and potentially for operating costs. For low levels of cofire, the biomass can often be premixed with the coal and delivered to the boiler, using the existing coal feeding system [1, 10, 32]. The exact level of cofire that can be achieved by this approach depends on the excess feeding capacity at a particular power plant, but is typically a few percent biomass by energy at full load. Once this limit is reached, higher levels of cofire cannot be achieved without reducing the capacity of the power plant [20]. To achieve higher levels of cofire without losing capacity, a dedicated biomass preparation and feeding system is required; cofire levels as high as 40% biomass by energy with no loss in capacity have been demonstrated, using separate feeding systems [12].

The economic model treats these two feed alternatives similarly, but with separate capital and operating cost distributions. These distributions are blended in defining national supply curves reflecting the variety of possible ways a given level of cofiring could be achieved across a state (e.g., 2% cofire could be achieved by retrofitting 100% of coal capacity to cofire 2% biomass or by retrofitting 10% of coal capacity to cofire 20% biomass). Cofire rates up to 40% biomass energy have been successfully demonstrated and there do not appear to be fundamental limits precluding even higher rates; however, most analyses generally consider an upper limit of 20% biomass energy in the near term. While this point can be debated, the cofire rate is limited to a maximum of 20% biomass energy, reflecting the near-term time horizon adopted for this analysis.

Cofiring can affect plant efficiency in a number of ways. Boiler efficiency losses have been reported to be roughly 0.5% for every 10% biomass input on a mass basis [10, 11, 13, 19]. However, several studies report no change in boiler efficiency [18, 20], and some reports indicate efficiency gains with cofiring [18, 19]. These effects on boiler efficiency appear to be largely due to the relative moisture content of biomass and coal being cofired: cofiring high-moisture biomass with low-moisture coal yields efficiency losses while cofiring low-moisture biomass with high-moisture coal yields gains. Fuel moisture related efficiency losses are unavoidable without drying biomass fuels before they are fired. A related HHV efficiency penalty for biomass is due to higher hydrogen to carbon ratio than coal, resulting in relatively more steam in its combustion products and a greater difference between higher and lower heating values than coal. Both of these moisture-related boiler efficiency losses are explicitly accounted for in the model.

The model does not account for any other potential sources of efficiency losses, including unburned carbon and increased parasitic load from dedicated biomass feed systems. Unburned carbon is a concern with cofire; however, many demonstrations report no significant increases in unburned carbon levels when cofiring [9, 10, 18, 19, 21]; this may be because the relatively high volatile matter content of biomass yields high carbon conversion efficiency of even large particles. As such, it appears that unburned carbon can be effectively managed with judicious selection of fuels and operating conditions. Parasitic load increases due to increased power demands to operate separate biomass feeding systems could theoretically be significant. However, there is insufficient information in the literature to effectively characterize this effect, which is expected to be

small.

2.2.2. Model characterization

The economics of cofiring depend largely on delivered biomass fuel costs, which vary from near zero or even negative cost for biomass waste streams, to projections above 100 dollars per ton (“\$/t”) for dedicated energy crops [14, 34, 35]. A simple model of the economics of cofiring is described that predicts electricity and pollutant mitigation costs and explicitly accounts for uncertainty and variability in a wide range of parameters such as fuel costs, fuel properties, and capital costs. Parameter values used in the model are specified in Table 2.1.

Table 2.1.
Cofire modeling parameters

Parameter	Min	Mode ^a	Max	Ref
<i>Economic</i>				
Utilization [%]		65		[36, 37]
Interest rate [%]		10		
Economic life [yrs]		10		
Capital cost for co-feeding [\$ /kW biomass] ^b	40	60	100	[1, 38]
Capital cost for separate feed [\$ /kW biomass] ^b	150	200	300	[1, 38]
Non-fuel O&M for coal [c/kWhe]		0.4		[36]
Biomass Non-fuel O&M Multiplier ^c	1.05	Var.	1.15	[1, 38]
Sulfur Emissions Cost [\$ /tSO ₂]		175		[39]
NO _x Emissions Cost [\$ /tNO _x]	750	1500	3000	[40]
<i>Biomass</i>				
Oxygen content [% wt, dry]		41		[6]
Carbon content [% wt, dry]		48		[6]
Hydrogen content [% wt, dry]	5.4	6	7.3	[6]
Sulfur content [% wt, dry]	0.02	0.07	0.15	[6]
Moisture content [% wt]	10	30	50	[6]
Heating value [HHV, MJ/kg, dry]	16.7	19.3	20.9	[6]
<i>Coal</i>				
Plant efficiency [net, HHV, %]		34		[36]
Cost [\$ /GJ]	0.53	1.15	1.66	[41]
Heating value [HHV, MJ/kg, dry]	14.8	23.5	30.1	[41]
Sulfur content [% wt, dry]	0.5	0.9	3	[41]
NO _x emissions rate [lbs NO _x /MBTU _{th}] ^d	0.15		0.42	[42]
<i>National supply curves</i>				
Coal cost, sulfur, carbon, and heating value	State specific			[41]
Urban Waste HHV [MJ/kg, dry basis] ^e		19.9		[6]
Mill Waste HHV [MJ/kg, dry basis] ^e		19.2		[6]
Forest Residue HHV [MJ/kg, dry basis] ^e		19.6		[6]
Agricultural Residue HHV [MJ/kg, dry basis] ^e		17.7		[6]
Biomass cost ^f	-50%	Var.	50%	[14]
Capital cost for cofire [\$ /kW biomass] ^g	Var.	Var.	300	[1, 38]

^a The deterministic value, or mode for variables with probability distributions; distributions for Monte Carlo simulation are triangular except where indicated. ^b Biomass is assumed to be co-fed with coal at cofiring rates below 2% biomass energy; higher cofire rates assume a separate feed. ^c The factor by which non-fuel O&M costs for biomass exceed those for coal; the mode is varied linearly with biomass thermal input between the minimum and maximum values. ^d A uniform probability distribution is used. ^e Averages of a large number of samples reported in EPRI biomass fuels database [6]. ^f The modal values are from state-specific biomass supply curves developed by Walsh et al. [14]; min and max values are $\pm 50\%$ of the mode. ^g The minimum value is linearly dependent on the state-specific cofire feed rate, “*f*”, across the range of \$50/kW to \$150/kW. The modal value is linearly dependent on the state-specific cofire rate across the range of \$60/kW to \$200/kW.

The cost of electricity (“COE”) is calculated as the energy-weighted average of the costs of electricity from biomass and from coal, as described in Equation 2.1.

$$(2.1) \text{ COE}(f) = f(C_B + \text{VOM}_B + F_B/\eta_B) + (1-f)(\text{VOM}_C + F_C/\eta_C)$$

In this equation, “ f ” is the fraction of electricity output from biomass and the subscripts “B” and “C” refer to biomass and coal respectively. The model considers three cost components, each evaluated on a specific electricity output basis: “C” is the capital charge; “VOM” is non-fuel variable operations and maintenance costs; and “ F/η ” is the fuel cost (“ F ” is the delivered fuel price on an energy basis and “ η ” is the net plant conversion efficiency). As indicated by the subscripts, different values for these parameters are used for coal and biomass. Although cofire fractions or rates are often defined on an energy *input* basis, plant efficiencies are specified for biomass and coal and costs are computed using the biomass cofire fraction, f , on an electricity *output* basis to avoid the confounding effects of differential fuel conversion efficiencies on cost calculations. This enables the economic impacts of decreased conversion efficiency to be allocated to the biomass electricity generated.

The baseline coal-fired power plant is assumed to have no outstanding capital costs. As discussed above, the model defines two levels of capital costs for cofiring biomass

depending on the cofire rate (see Table 2.1). The underlying assumption is that low levels of cofire—up to 2% biomass input by energy—can be achieved by co-feeding the biomass through the existing coal handling system, while higher levels of cofire—between 2 and 20% biomass input by energy—require a separate feeding system.

Non-fuel operation and maintenance (“O&M”) cost parameters for coal combustion are based on US averages [36]. Fixed O&M costs are incorporated into the variable O&M parameters, as specified in Table 2.1, by assuming an annual plant utilization of 0.65, roughly the national average for coal-fired power plants [36]. The specific O&M costs for biomass (“ VOM_B ”) are generally somewhat higher than those for coal [1, 38], and are estimated in the model by adding a premium to coal O&M on a thermal energy basis. The premium applied ranges between 5% and 15% of the coal non-fuel O&M and is defined to be dependent on the cofire rate, with higher premiums associated with higher cofire rates (Table 2.1).

As mentioned above, the model specifies different net energy conversion efficiencies (fuel-to-electricity) for coal and biomass to accurately account for the impact of cofiring on power plant operations. The net conversion efficiency for coal is assumed to be constant at 34% (HHV), which is the average value for plants built after 1950 [36]. To estimate the conversion efficiency of the biomass to electricity, a higher heating value efficiency penalty is calculated from the relative moisture content and hydrogen:carbon ratio of the biomass fuel using the ASME Heat Loss method for calculating boiler efficiencies [43]. Specifically, this method is applied to calculate the boiler efficiency for

biomass using the distributions for biomass fuel parameters defined in Table 2.1. 20% excess air, 150°C exhaust temperature, 1.5% losses due to unburned combustibles for both the biomass and the coal, and 1.5% minor losses (e.g., moisture in air), which are typical values for these parameters, are also assumed. This approach generally predicts the reductions in boiler efficiency observed in commercial cofiring demonstrations within $\pm 0.5\%$ [11, 13, 18, 19].

The net plant efficiency for biomass is then estimated with Equation 2.2, which implicitly assumes identical balance-of-plant thermal efficiencies and parasitic loads for biomass and coal. A plant-wide energy-input-specific parasitic load of 6% is explicitly assumed along with a baseline coal boiler efficiency of approximately 86%, as estimated by applying the ASME Heat Loss method to typical coal composition estimates, as specified in Table 2.1, with the additional parameter values described above.

$$(2.2) \quad \eta_B = \eta_{B,Boiler} \times \frac{\eta_C + P}{\eta_{C,Boiler}} - P$$

In this equation, “ $\eta_{B,Boiler}$ ” and “ $\eta_{C,Boiler}$ ” represent the boiler efficiencies for biomass and coal, respectively, and “ P ” represents the plant-wide input-specific parasitic load.

The efficiency penalty due to fuel moisture can be substantial for biomass fuels with high moisture content; for example, the conversion efficiency of biomass that contains 50%

moisture by mass to electricity is roughly 30% (HHV) versus the 34% (HHV) typical of coal. However, this is still significantly higher than the 16-25% efficiency (HHV) of existing dedicated biomass power plants [1, 3].

As discussed above, biomass cofiring can yield joint reductions in CO₂, SO_x, and NO_x emissions. The model includes only those SO_x emissions reductions due to the lower sulfur levels in biomass compared to coal, as described by equation 2.3. This is conservative given known reactions between biomass alkali and alkaline components with coal sulfur [8, 9].

$$(2.3) \quad ES(f) = f \frac{FS_B}{\eta_B} + (1-f) \frac{FS_C}{\eta_C}$$

In this equation, “ $ES(f)$ ” is the emissions per unit energy output and “ FS ” is the energy specific fuel sulfur content [kgS/GJ]. Reductions in SO_x emissions are based on coal and biomass sulfur content distributions described in Table 2.1, which are defined to be representative of the US supply.

The CO₂ emissions per unit electrical output, “ $EC(f)$ ”, are computed using an identical formula to Equation 2.3, except that the energy-specific sulfur content (“ FS ”) is replaced with the energy-specific carbon content, which is assumed to be zero for biomass. In practice, fossil energy resources less than 5% of the energy content of the biomass are

typically consumed in its cultivation and processing [1].

As mentioned above, the effects of cofiring on NO_x emissions are much more difficult to specify than the effects on SO_x or CO₂ emissions because of the complexity of NO_x formation in coal boilers. Moreover, demonstration results indicate substantial variability in NO_x reductions [8-13]. For this analysis NO_x emissions per unit electrical output, EN(*f*), are computed assuming a linear reduction proportional to the fraction of biomass energy input. While not supported by specific theoretical mechanisms, this level of reduction is broadly consistent with the findings of many cofiring demonstrations [10]. The uncertainty in the effect of cofiring on NO_x formation is considered here to be too great for effective characterization at a level that is consistent with the treatment of other sources of model uncertainty. However, this is at least partially mitigated within the model by the wide range used for the baseline NO_x emission rate (from 0.15 to 0.42 lbs NO_x/MBTU_{th}). These values span the emission rate from a low-NO_x boiler to the current US-fleet average boiler [42].

The cost of pollutant mitigation is computed by dividing the change in cost of electricity by the change in emission rates. Equation 2.3 specifies the calculation of the cost of mitigation (“COM”) for SO_x; similar equations are used to calculate the cost of mitigation of CO₂ and NO_x emissions.

$$(2.4) \quad COM = \frac{COE(f) - COE(0)}{ES(0) - ES(f)}.$$

Monte Carlo simulation is conducted using the distributions for capital costs, O&M cost and O&M cost premium, and fuel properties listed in Table 2.1. The distributions generally reflect the ranges of likely values for each parameter, as described in the literature. For example, the distributions of biomass properties listed in Table 2.1 are based on analyses of over 600 different biomass fuel samples [6]. Figure 2.1 illustrates the empirical cumulative distributions from this dataset with the distributions used for model simulations.

2.2.3. Results

Figures 2.2 and 2.3 present the costs of electricity and pollutant mitigation of cofire as a function of biomass price. Figure 2.2a shows the overall cost of electricity produced; Figure 2.2b shows the cost of the electricity produced from biomass ($C_B + VOM_B + F/\eta_B$ from Equation 2.1). The curves in Figures 2.2 and 2.3 are based on a typical US coal-fired power plant burning average US coal, as specified by the mode values listed under the subheading “coal” with the distributions for capital cost, O&M cost, O&M premium, and biomass fuel properties described in Table 2.1.

The calculations of electricity and mitigation costs as functions of biomass price illustrate several important points. First, the variation in these costs across the range of reasonable

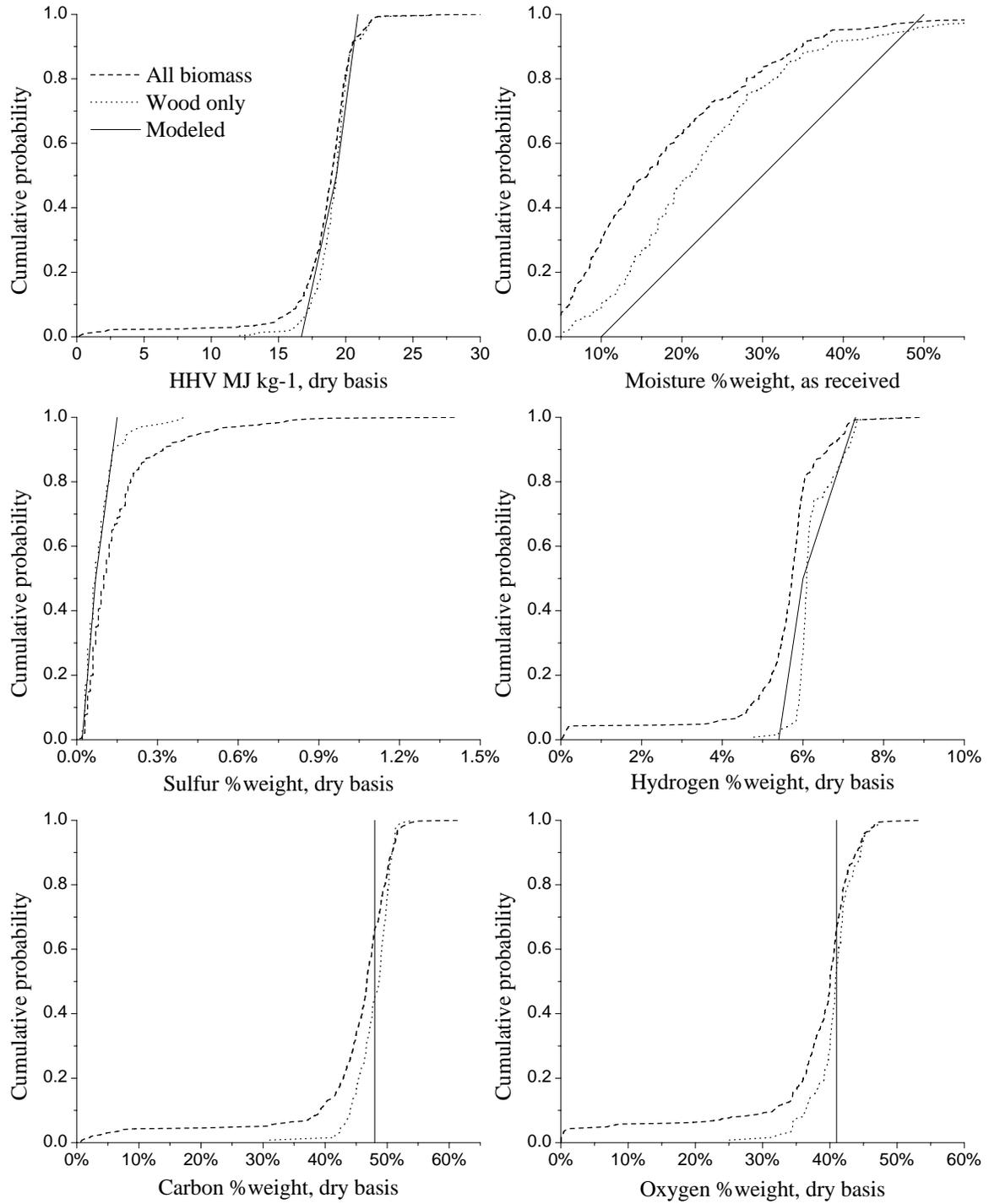


Figure 2.1. Empirical and modeled distributions for biomass fuel parameters. Dashed curves represent empirical distributions from analysis of over 600 biomass fuel samples [6]; dotted curves represent empirical distributions from analysis of over 300 wood (only) fuel samples [6]; solid lines represent the modeled distributions for Monte Carlo simulations.

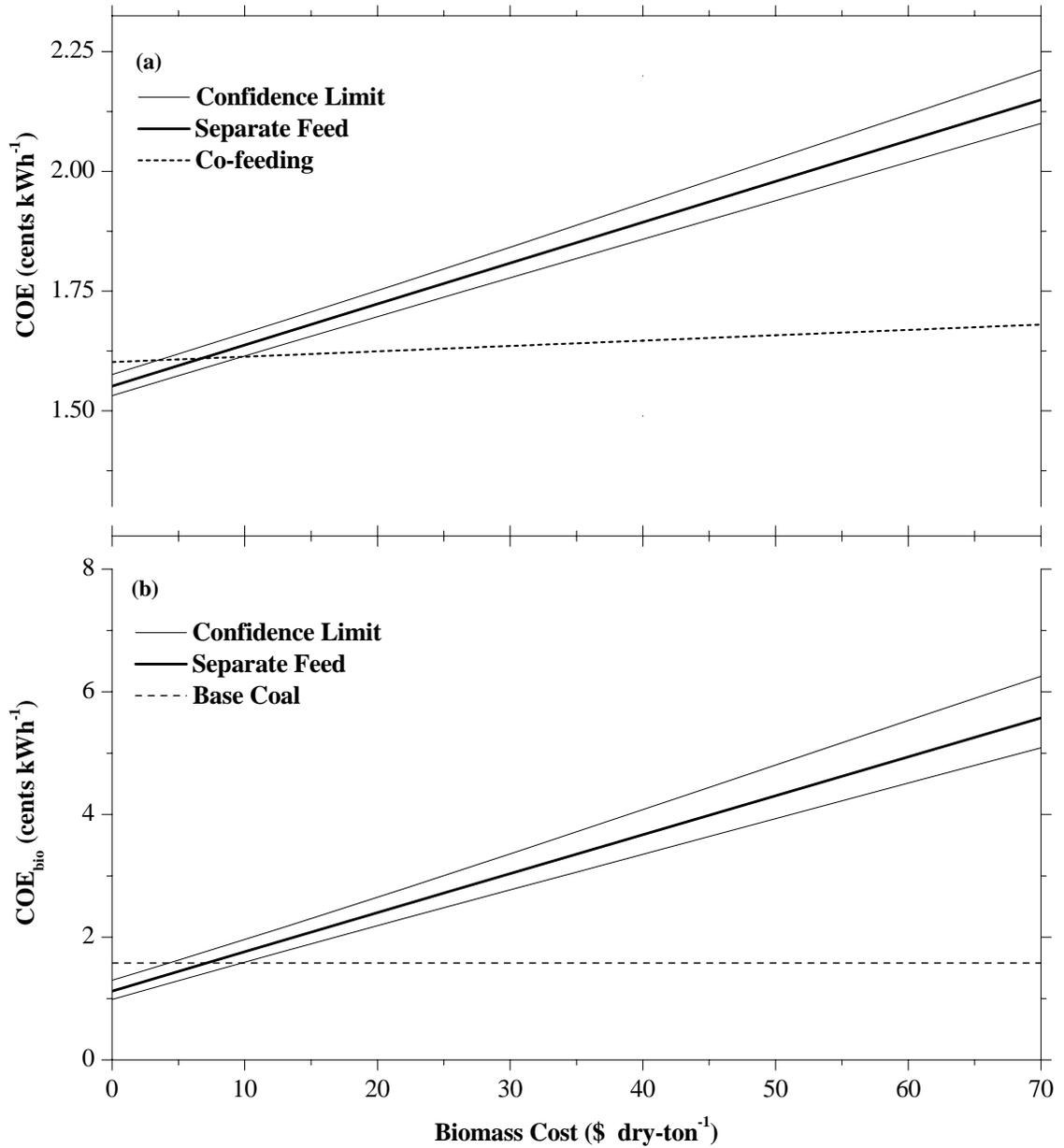


Figure 2.2. Cost of electricity from co-fire as a function of biomass cost. Plant-level cost of electricity ("COE") is plotted as (a) overall cost of electricity (coal and biomass), and (b) cost of electricity from biomass, which equals $C_B + VOM_B + F_B/\eta_B$ from equation 2.1. The separate feed and co-feeding curves correspond to cofiring rates of 15% and 2%, respectively. The 5% and 95% confidence limits are shown for the separate feed case from Monte Carlo simulation. The cost of electricity from the base coal plant is 1.6 c/kWh.

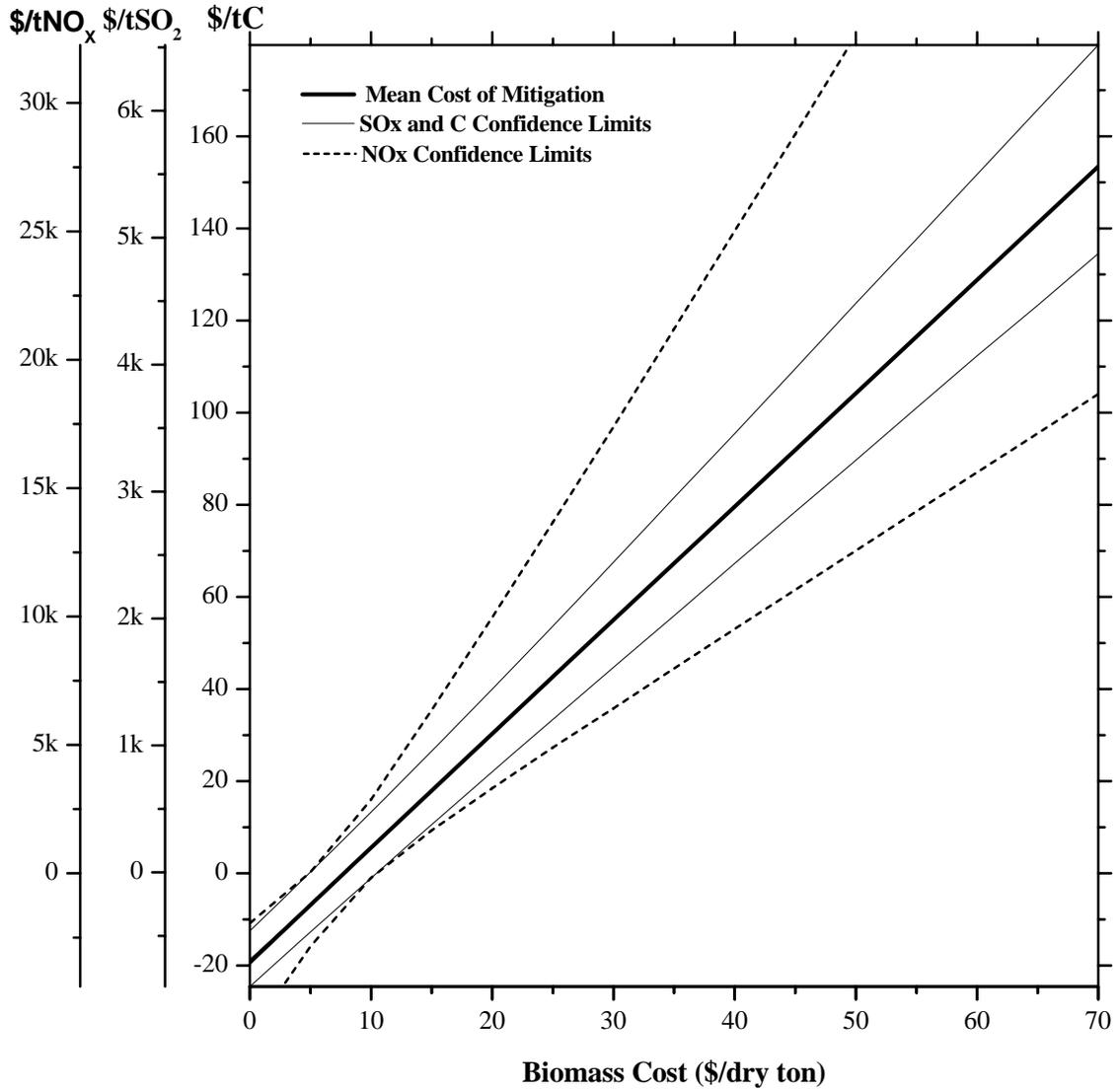


Figure 2.3. Mitigation costs plotted as a function of biomass price. Mitigation costs for carbon, sulfur, and nitrogen oxides are plotted as a function of biomass price assuming co-fire with a separate feed system and a co-fire rate of 15% (output energy basis). The 5% and 95% confidence limits are from Monte Carlo simulation with the distributions defined in Table 2.1.

biomass costs (0 to 70 \$/t) is much greater than range between the confidence limits, underscoring the importance of biomass fuel cost in cofire economics. Second, biomass must be available at low cost for cofire to produce electricity at the same price as the base coal plant. Figure 2.2b indicates that the cost of electricity from biomass is comparable to that from coal at a biomass price of around 7 \$/t; the delivered cost of biomass must be at or below this break-even price for cofiring to be cost-competitive with a typical coal plant burning average US coal. However, the curves in Figures 2.2 and 2.3 do not account for any economic benefit for reductions in SO₂ and NO_x emissions due to cofiring. Including these benefits by adding, for example, the cost of sulfur emissions permits (equal to $ES \times Permit_Price$) to the cost of electricity can improve the economics of cofiring. The break-even price for biomass can be as high as 20 \$/t with the sulfur and NO_x emissions levels and emission credit prices in the model.

Pollutant mitigation costs as a function of biomass price are shown in Figure 2.3.

Although cofire reduces SO₂ and NO_x emissions, these reductions are not generally cost-competitive with existing technologies, except at low biomass prices. (Since the markets for these pollutants are reasonably well developed, permit prices are a plausible measure of the marginal cost of emissions control.) For example, biomass must be available at a price of roughly 10 \$/t for cofire to provide reductions in SO₂ at costs comparable to the market price of roughly 175 \$/tSO₂ for emissions allowances. This value, 10 \$/t, can also be viewed as the break-even price at which biomass must be available in order for cofire to produce electricity at the same cost as a typical coal power plant burning average US coal and paying a price of 175 \$/tSO₂ for sulfur emissions. For the case of NO_x

emissions, biomass must be available at a price of 12 to 17 \$/t to provide NO_x reductions that are comparable to emissions allowance prices of 2000 to 4000 \$/tNO₂—although, as described above, the uncertainty in NO_x reductions from cofire is large and not well characterized in the model. Further, cofire at the levels considered here will likely not yield reductions in SO₂ and NO_x sufficient to avoid use of other control strategies to meet recently required reductions in NO_x emissions (i.e., the NO_x SIP Call [44]) or the SO_x emission constraints imposed by Title IV of the Clean Air Act Amendments of 1990.

Figure 2.3 shows that cofiring can mitigate carbon emissions for prices between -20 and 150 dollars per ton carbon (“\$/tC”), or between -5 and 41 dollars per ton carbon dioxide (“\$/tCO₂”), depending on the cost of biomass. While the cost of controlling CO₂ emissions without cofire is more uncertain than for criteria pollutants (because there is far less real-world experience), these costs are comparable with other technologies for abating CO₂ emissions from electricity generation, as discussed below.

The analysis shown in Figures 2.2 and 2.3 is based on a US-average power plant burning US-average coal in order to emphasize that the cost of cofiring in a specific plant operating with known coal quality is relatively certain—the confidence intervals are narrow, at a given cost of biomass. Varying coal properties such as coal cost, heating value, or sulfur content can alter the plant level economics by shifting the curves and effectively changing the breakeven price for biomass at which cofire is cost competitive with the coal. Figure 2.4 illustrates the relative sensitivity of the breakeven biomass price to several key parameters. As illustrated, the break-even biomass price is most sensitive

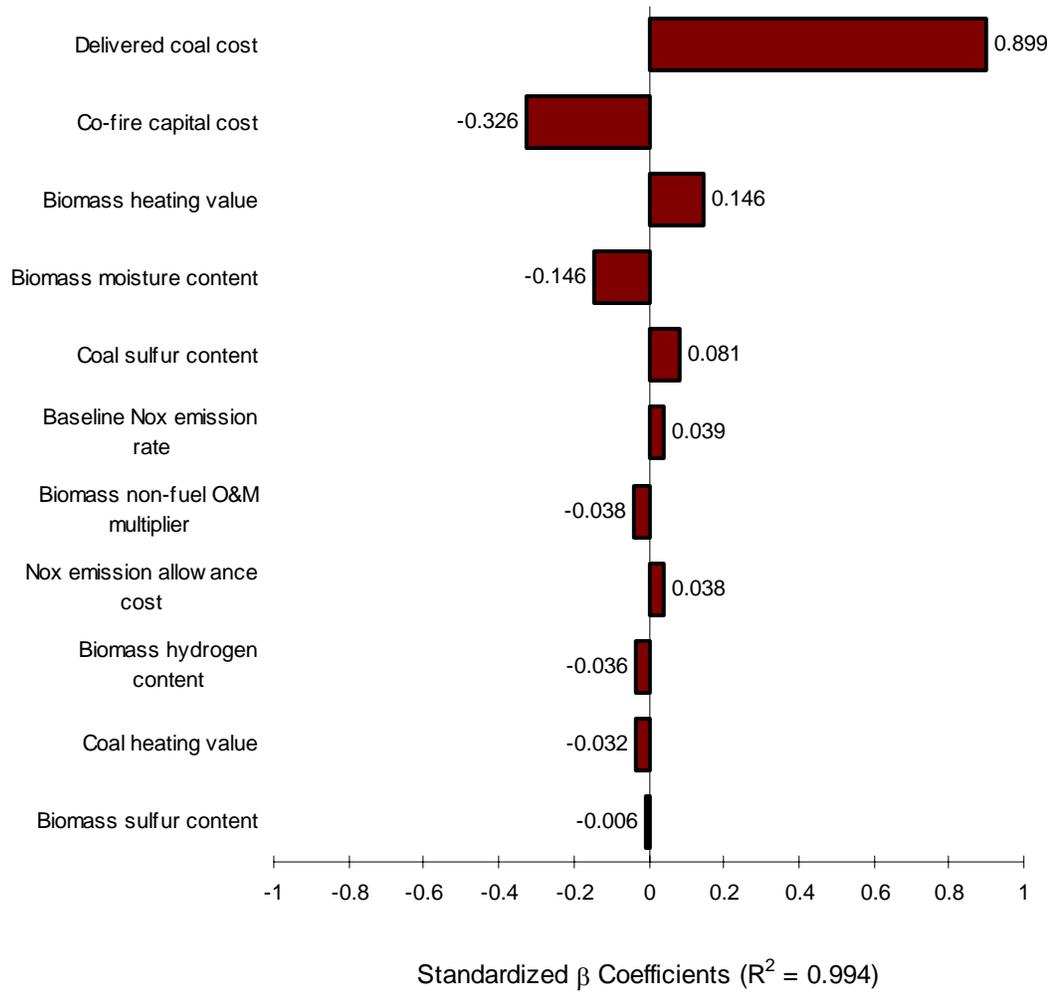


Figure 2.4. Tornado diagram of breakeven biomass fuel price sensitivity. This figure plots the standard ‘ β ’ coefficients from regression of the breakeven biomass price simulation output on the simulation input parameters sampled from the distributions defined in Table 2.1.

to coal cost—plants burning higher priced coal have a higher breakeven price for biomass. Coal sulfur has a more modest influence on the breakeven price. As such, the economics of cofire are most attractive for power plants with high NO_x emissions operating on high cost, high sulfur coal—in this scenario the breakeven price of biomass approaches 20 \$/t versus 7 \$/t for the average plant burning average coal shown in Figure 2.2.

Alternatively, cofire in a plant with inexpensive, low sulfur coal will result in a breakeven price much less than 7 \$/ton. Other studies have examined in more detail the different combination of factors that influence the economics of cofire at the plant level [1, 24, 38, 45]; the range of breakeven prices for biomass discussed here are consistent with these analyses[1, 24, 38, 45].

The cost of biomass in existing markets and the expected delivered cost of energy crops provide useful benchmarks for evaluating the cost curves shown in Figures 2.2 and 2.3. For example, California produces relatively large amounts of biomass electricity and therefore has a reasonably well-developed biomass fuel market. During the 1990's biomass prices ranged between 35 and 55 \$/t [46], much higher than the break-even price for cofire from this analysis. This underscores the point that cofire is not generally cost-competitive in existing energy markets.

2.3. Aggregate supply curve modeling

The resolution of plant-level economics of cofire, as accomplished through the analysis described above, is useful for understanding plant-specific economics with known plant and fuel parameters and for making general comparisons between cofire and other options for near-term carbon mitigation in the electric sector. However, its utility for understanding the potential contribution of cofire at a higher level (e.g., at the national level) is limited without explicit consideration of biomass supply, especially with respect to the co-location of biomass and existing coal-fired power plants. To provide some resolution of this central issue, the cofire cost model described above is integrated with U.S. biomass fuel availability estimates and electric sector coal consumption data at the state level. These results are then aggregated at the national level to generate national supply curves for electricity generation and carbon mitigation with cofire. This approach uses state-level averages to account for the effects of variations in parameter values such as coal cost and coal quality on national cofire economics.

2.3.1. Modeling basis

Walsh et al. [14] provides state-specific biomass fuel supply curves at delivered costs of 20, 30, 40, and 50 dollars per dry ton (“\$/t”) for several classes of materials including forest residues, mill residues, agricultural residues, urban wood wastes, and energy crops. The cost estimates behind these supply curves include harvest, collection, and

transportation to the power plant, assuming a haul distance of 50 miles to the power plant, and account for a reasonable profit margin for suppliers. For this analysis, only cofire potential using wood and agricultural residues is considered based on data reported by Walsh et al. [14]. Cofire with wood is a natural first step because it poses few technical challenges; agricultural residues are considered separately because they pose more significant technical challenges than wood but represent a significant fraction of the available biomass fuel supply. We do not consider the potential of cofire with energy crops because their near-term economic viability is not clear.

The supply curves of Walsh et al. [14] are compared to other published fuel surveys [35, 45, 47, 48] in Table 2.2 as a consistency check; however, such comparisons are inherently difficult because many surveys report national estimates without spatial resolution, provide residue availability only for a specific region, and/or do not provide cost information. The survey by Walsh et al. [14] is unique in that it provides systematic biomass supply curves at the state level. In general, comparisons among different surveys indicate broad consistency in the estimates of the total available resources, suggesting that amount of available biomass residues estimated by Walsh et al. [14] is reasonable. There is inconsistency in the estimates of delivered costs among the surveys, with the costs from Walsh et al. [14] being generally higher, and therefore more conservative. Reference lists have been compared to ensure that the different surveys are based on different primary sources.

Table 2.2
National U.S. biomass supply estimates

Reference	Quantity [Tg/yr]	Marginal Cost [\$/Mg]	Modeled Quantity [Tg/yr]	Modeled cost [\$/Mg]
<i>Urban wood waste</i>				
[35]	58	26		
[48]	33 (69) ^a		33	33
[49]	25 (43) ^b			
<i>Mill wastes</i>				
[48]	6 (101) ^a		82	55
[49]	7 (64) ^b			
<i>Forestry residues</i>				
[49]	37 (58) ^{b, c}		41	55
<i>Agricultural residues</i>				
[49]	103 (388) ^b		137	55
[50]	142 (227) ^d	55		
<i>Energy crops</i>				
[49]	142 - 342 ^e		171	55

National biomass resource estimates from several literature sources are compared with those used in modeling the national cofire supply curves, which were taken from Walsh et al. [14]. Quantity estimates from the literature are generally similar to those from Walsh et al. [14], depending on the assumptions underlying the estimates. In particular, for urban wood wastes, forestry residues, and agricultural residues, estimates from Walsh et al. [14] are generally similar to other estimates of currently available resources; however, for mill wastes, which are generally well utilized for process heat and power applications coupled with mill processing, estimates from Walsh et al. [14] are more similar to other estimates of potentially available resources. ^a estimated total recoverable resources available in 1993 presented with estimated total resource produced in 1993 in parentheses. ^b estimated currently available and unexploited resources presented with estimated total potentially available by mid century in parentheses. ^c excludes potential residues from fuel treatments, which is estimated to be capable of providing an additional 54 Tg/yr. ^d estimated potential supply as of 2003 presented with potential future supply within two decades in parentheses. Also note that references [14], [50], and subsequent analyses by McKeever, of reference [48], are cited within reference [49], and that references [14] and [49] share primary authors. ^e potential range in perennial energy crop production by mid century.

State-level coal data are reported from the U.S. Department of Energy [51]. State-average coal costs [\$/MMBTU] and heating values [BTU/lb] are provided directly in

Table 4 of the Department of Energy report titled Cost and Quality of Fuels for Electric Utility Plants 2001 [51]. However, state-level coal sulfur data are provided only categorically in Table 5 of the report [51] by indicating the amount of coal consumed by state within specified sulfur content ranges. For example, according to this report, Massachusetts consumed 207 short tons of coal in the year 2000 with sulfur levels greater than 0.5% and up to 1.0%. Therefore, estimates of state-average coal sulfur contents were calculated as a weighted average by multiplying the fraction of coal consumed within each sulfur content category by the average of the category boundary values and then summing across categories. This method will tend to concentrate state averages toward central values, as extreme sulfur content coal is captured only by boundary categories (e.g., high sulfur coal content is characterized as greater than or equal to 3%), and therefore will tend to reduce the variability across states.

2.3.2. Model characterization

State-average cofire rates are defined on a biomass energy *input* basis using Equation 2.5 and converted to an electricity *output* basis with Equation 2.6.

$$(2.5) \quad f_{I,i}(F_B) = \frac{E_{B,i}(F_B)}{E_{C,i}}$$

$$(2.6) \quad f_{O,i}(F_B) = f_{I,i}(F_B) \times \frac{\eta_B}{\eta_C}$$

In these equations, “ $f_{I,i}(F_B)$ ”, “ $f_{O,i}(F_B)$ ”, and “ $E_{B,i}(F_B)$ ” are the i^{th} state’s average cofire rate on energy input basis, average cofire rate on an energy output basis, and total biomass energy (HHV) available, respectively, at biomass fuel price “ F_B ”; “ $E_{C,i}$ ” is the i^{th} state’s coal energy (HHV) consumed for power generation; “ η_B ” and “ η_C ” are the net plant efficiencies for biomass and coal, respectively. The biomass energy available in each state is calculated from the biomass supply curves developed by Walsh et al. [14] with the higher heating values from Oak Ridge National Laboratory Biomass Resource Estimates [52]. State-level coal consumption data are from U.S. Department of energy data, as described above [51]. Net coal-to-electricity conversion efficiencies for coal are assumed to be constant at 34% across all states. State-average biomass-to-electricity conversion efficiencies are estimated by calculating a biomass fuel moisture efficiency penalty, as described above, using state-average coal property data [51] and the biomass fuel property distributions listed in Table 2.1. State-average biomass energy input, $f_{I,i}(F_B)$, is limited to 20%, which results in relatively lower biomass prices in states with excess supply and limits the national cofire rate as regional imbalances in biomass supply and coal capacity result in stranded resources. These effects can be seen in Table 2.3, which compares state-level biomass supply with potential cofire capacity. National-average cofire rates (electricity output basis) are calculated at each biomass fuel price as the average of the state-average rates weighted by the fraction of national coal energy consumption within each state.

Table 2.3.
State-level coal consumption and biomass supply

State	Coal consumption [PJ yr ⁻¹]	Wood residues [% coal consump.]	Agricultural residues [% coal consump.]	Total residues [% coal consump.]
<i>North East</i>				
Connecticut	27	52%	0%	52%
Maine	13	>100%	0%	>100%
Massachusetts	184	13%	0%	13%
New Hampshire	41	88%	0%	88%
Rhode Island	0	>100%	>100%	>100%
Vermont	0	>100%	>100%	>100%
Delaware	39	6%	14%	20%
Maryland	335	5%	4%	9%
New Jersey	106	15%	1%	16%
New York	335	29%	1%	30%
Pennsylvania	1,429	6%	1%	7%
<i>South East</i>				
Alabama	858	25%	0%	25%
Arkansas	303	46%	6%	51%
Florida	816	20%	0%	20%
Georgia	868	25%	2%	27%
Louisiana	258	43%	3%	45%
Mississippi	162	>100%	0%	>100%
North Carolina	833	19%	2%	21%
South Carolina	420	31%	1%	32%
Virginia	431	25%	2%	27%

Table 2.3.---Continued

State	Coal consumption [PJ yr ⁻¹]	Wood residues [% coal consump.]	Agricultural residues [% coal consump.]	Total residues [% coal consump.]
<i>Mid-West</i>				
Illinois	939	3%	46%	49%
Missouri	761	7%	10%	16%
Wisconsin	515	14%	18%	32%
Indiana	1,391	2%	15%	18%
Michigan	835	9%	9%	18%
Ohio	1,440	2%	9%	12%
Tennessee	657	15%	3%	17%
West Virginia	1,065	5%	0%	5%
Kentucky	1,090	6%	4%	10%
<i>Central Plains</i>				
Kansas	381	7%	40%	47%
Iowa	414	3%	>100%	>100%
Minnesota	377	18%	56%	75%
Nebraska	226	2%	>100%	>100%
North Dakota	373	3%	18%	21%
Oklahoma	406	6%	15%	21%
South Dakota	43	18%	>100%	>100%
Texas	1,742	8%	5%	13%

Table 2.3.---Continued

State	Coal consumption [PJ yr ⁻¹]	Wood residues [% coal consump.]	Agricultural residues [% coal consump.]	Total residues [% coal consump.]
<i>Mountain and Dessert</i>				
Arizona	457	4%	1%	5%
Colorado	407	5%	11%	16%
Montana	165	42%	4%	46%
Nevada	202	3%	0%	3%
New Mexico	347	3%	2%	6%
Utah	402	2%	1%	3%
Wyoming	528	3%	1%	4%
<i>Pacific and North West</i>				
California	32	>100%	81%	>100%
Idaho	1	>100%	>100%	>100%
Oregon	44	>100%	6%	>100%
Washington	111	>100%	22%	>100%

Annual state coal consumption for power applications is calculated as the product of coal consumed in 1999 and average higher heating values [41]. Wood and agricultural residue availability is presented as a percentage of coal consumption by multiplying residue availability estimates from Walsh et al. [14] by characteristic heating values, as presented in Table 2.1 and dividing by the annual coal consumption.

State-average electricity and mitigation costs are computed for each price in the biomass supply curves using Equations 2.1-2.4 with the state-average cofire rates, conversion efficiencies, and coal properties described above. National-average electricity and mitigation costs are calculated for each price in the biomass supply curves as the average of state-average costs weighted by the fraction of national biomass electricity produced within each state. For example, the national average cost of biomass electricity, $COE_{B,N}(F_B)$, is calculated as

$$(2.7) \quad COE_{B,N}(F_B) = \sum \frac{COE_{B,i}(F_B) \times f_{O,i}(F_B) \times E_{C,i}}{f_{O,N}(F_B) \times E_{C,N}}$$

where “ $COE_{B,i}(F_B)$ ” are the i^{th} state’s average cost of biomass electricity from cofire at biomass cost “ F_B ”; “ $f_{O,N}(F_B)$ ” and “ $f_{O,i}(F_B)$ ” are the national-average and i^{th} state’s average cofire rate (electricity output basis) at biomass cost “ F_B ”, respectively; and “ $E_{C,N}$ ” and “ $E_{C,i}$ ” are the national-average and i^{th} state’s annual coal energy consumption for power production, respectively. Monte Carlo simulation is used to evaluate the 90% confidence intervals of national average electricity and mitigation costs for each biomass price in the supply curves given uncertainty in fuel costs, capital costs, O&M costs, and biomass fuel parameters represented by the distribution parameters in Table 2.1.

As illustrated by the results in Figure 2.2, biomass fuel cost is a critical parameter for

determining cofire costs. For the simulations, a large uncertainty ($\pm 50\%$) is assigned to biomass prices at each point in the supply curves because the absence of widespread biofuel markets makes estimates of biomass cost and availability, such as those by Walsh et al. [14], highly uncertain. The survey's systematic methodology provides a level of consistency in the estimates, but also leads to correlated price uncertainty across states (e.g., if the cost estimates for a specific resource subcategory are underestimated in one state, then the fuel costs for that subcategory will likely be higher than expected across all states). In addition, biomass fuel prices are likely to be highly variable, dominated by local market conditions, as high transportation costs will require a substantial price differential to induce trade between local or regional markets. This issue is underscored by the estimated supply and demand potentials in Table 2.3.

2.3.3. Results

Several interesting trends are apparent when comparing the state-level biomass residue and coal consumption data shown in Table 2.3. Major coal consuming states fall into three general categories: states with substantial wood residues, states with substantial agricultural residues, and states with little biomass residues. Southeastern states generally fall in the first category with substantial coal consumption and large amounts of wood residues. Midwestern states, such as Illinois, Indiana, and Ohio, have little wood residues but high levels of agricultural residues. The final category include states such as Kentucky, West Virginia, and Pennsylvania which have high coal consumption but relatively little biomass residues available for cofire. Finally, although there are significant biomass residues available in the western United States, these resources cannot be used effectively for cofire due to the lack of coal-fired power plants in the region and the prohibitively high cost of transporting biomass.

National supply curves for biomass electricity and carbon mitigation from cofire are shown in Figure 2.5. Results are shown for two scenarios: one that considers only wood residues (urban waste wood, mill waste, and forestry residues) and a second that considers both wood and agricultural residues. Figure 2.5a plots electricity and mitigation costs without accounting for costs from NO_x and SO_x emissions, whereas Figure 2.5b includes this accounting.

These results suggest that cofire could substantially increase the U.S. supply of biomass

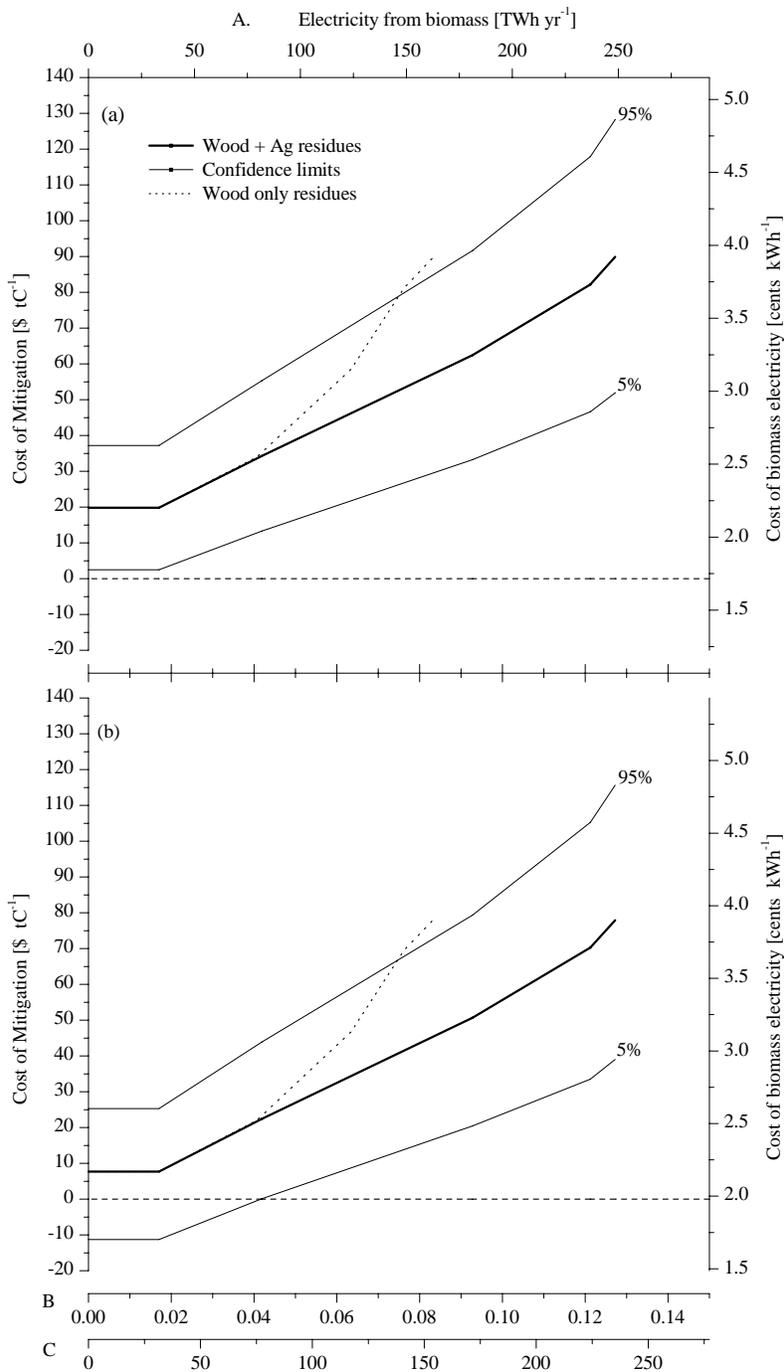


Figure 2.5. U.S. national cofire supply curves. Supply curves are plotted as a function of (A) biomass electricity from cofire [TWh yr⁻¹], (B) national cofire rate on an energy output basis, f , and (C) annual CO₂ reduction [Mt yr⁻¹]. Panel (b) includes accounting for SO₂ and NO_x emissions; Panel (a) does not. Confidence limits apply to the wood plus agricultural residues case and are from Monte Carlo simulation with the parameter distributions in Table 2.1. The dashed horizontal lines define zero mitigation cost.

electricity at reasonable cost; for example, the mean estimate of the Monte Carlo simulation is that cofiring wood residues could supply roughly 160 TWh annually at a cost of around 4 cents/kWh, which increases to almost 250 TWh if agricultural residues are included in the analysis. Put another way, these results suggest that biomass residue cofire could provide 4 to 7% of current net generation for around 4 cents/kWh.

Moreover, cofire appears to be cost effective in reducing carbon emissions from coal-fired power plants; for example, a 5% reduction in national coal fired power plant CO₂ emissions, ~100 million metric tons CO₂ (“Mt CO₂”) annually, could be achieved at a cost between 30 and 40 \$/tC (8-11 \$/tCO₂).

Accounting for the value of NO_x and SO_x emissions costs in the calculation reduce the carbon mitigation cost by roughly 10 \$/tC (~3 \$/tCO₂) but has only a small effect on the relative cost of biomass electricity (see Figure 2.5). To further resolve this effect, Figure 2.6 plots the carbon mitigation supply curve for several variants of pollutant cost accounting. The figure illustrates that the mitigation cost reduction is dominated by NO_x emissions benefits. The effect of cofire on NO_x emissions is highly uncertain, as discussed above. Therefore, the mitigation cost benefit from pollutant cost accounting in these results should be interpreted somewhat conservatively.

Only limited comparisons can be made between the current results and those from previous analyses of national cofire potential because of the relative lack of cost information provided by the previous analyses. The projections illustrated in Figure 2.5a are similar to an EPRI estimate that 2.3% of coal generated electricity could be offset at a

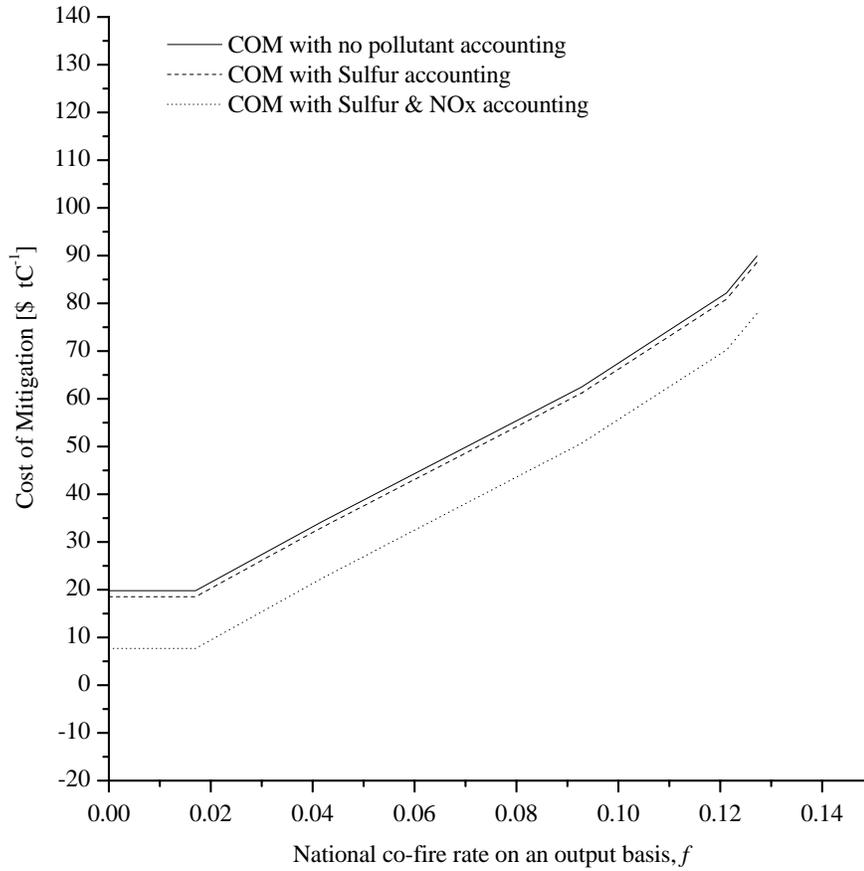


Figure 2.6. Carbon mitigation supply curve with alternate pollutant accounting schemes. The best estimate carbon mitigation supply curve from Figure 2.5 is plotted with three alternate pollutant accounting schemes: without accounting for pollutant emissions; with sulfur emissions accounting; and with both sulfur and NO_x emissions accounting.

net cost of 22.60 \$/tC [24]. The DOE projects that a renewable portfolio standard requiring 10% of electricity production from renewable sources would result in almost 10 TWh of electricity generated annually with cofire [53]. No cost information is provided by the DOE analysis confounding direct comparison with the current results. However, Figure 2.5 indicates that this level of cofire is feasible at a cost of approximately 2.2 cents/kWh and that higher levels of cofire are feasible at reasonable cost compared to other renewable energy technologies, suggesting that the DOE analysis may underestimate cofire potential. This may be because in that analysis, cofire is capped at 5% biomass share by energy at an individual coal-fired power plant and at a level of 4% of coal consumption on a national basis, which appear to be unnecessarily restrictive constraints. Results from a DOE working group that considered cofire under conditions of carbon constraints appear to have been similarly conservative, relative to the current results [54]. They estimate that cofire could generate 58-88 TWh of electricity in 2010 with dedicated energy crops, supplied at 32 \$/t, providing a substantial fraction of the biomass feedstock. The current results indicate that roughly 131 TWh could be produced with fuel costs up to 30 \$/t. However, these feedstock costs may be optimistic for energy crops, given recent production cost projections; Walsh et al. project that switchgrass becomes economically viable at a price of 40 \$/t with substantial production only feasible at prices around 55 \$/t [14, 55].

2.4. Discussion

Biomass-coal cofiring is cost competitive within current energy markets only where there is reliable biomass feedstock at very low cost. While the maximum delivered cost of biomass at which cofire is competitive depends on plant-specific parameters such as coal fuel costs, sulfur content, and NO_x emissions, the modeling results suggest that the cost is generally between 7 and 20 \$/t. Such low-cost biomass is available only in very limited quantities and niche markets. Therefore, widespread cofire deployment should only be expected if financial incentives (e.g., tax credits or incentive payments) or other policy instruments supporting renewable energy or carbon mitigation (e.g., renewable energy portfolio standards or carbon constraints) are implemented.

In spite of cofire's inability to compete widely with conventional power systems, cofire does offer benefits that could support widespread deployment under certain policy scenarios. The general arguments presented in Sections 2.1 and 4.1 along with the modeling results presented in Sections 2.2 and 2.3 suggest that the most important application of cofire is as a means for significant near-term reductions in CO₂ emissions. Its potential contribution in this regard depends on its competitiveness with other control strategies. The results presented in Section 2.3 suggest that biomass residue cofiring could reduce U.S. CO₂ emissions from coal-fired electric utilities by 10% (about 3% of US emissions) at a carbon price between 50 and 70 \$/tC (Figure 2.5). This is substantially lower than the near-term cost of roughly 100 \$/tC (27 \$/tCO₂) or larger for reducing emissions by replacing existing capacity with non-fossil sources such as wind or

nuclear, or by building new fossil fuel plants (or retrofitting existing plants) to capture and store CO₂ [56-58]. Further, cofiring can achieve these emissions reductions in the very near term. As a result, the relatively modest reductions possible with biomass residue cofire could represent important contributions toward the near-term reductions required to achieve emissions trajectories for long-term atmospheric stabilization of CO₂ concentrations at desirable levels. Moreover, there are several pathways where cofire could support substantially deeper mitigation over time, as described above.

The analysis developed in Section 2.3 specifically incorporates geographic relations between available biomass resources and installed coal capacity to provide a more accurate picture of cofire's potential contributions for increasing renewable energy generation and mitigating carbon emissions, given the high transportation cost of biomass. However, greater spatial resolution could provide substantially more accurate estimates. Ideally, biomass supply curves could be evaluated on a plant-specific basis with delivered costs estimated as a function of distance to the facility. At this level of granularity, plant-specific data for model parameters could also be incorporated, including coal fuel parameters such as cost, heating value, and sulfur content as well as operational parameters such as heat rate, boiler efficiency, excess feed capacity, NOX emissions rate, and pollutant control systems. For example, the amount of excess feed capacity determines the level of cofire that can be achieved without investing in separate feeding systems, and so directly impacts capital costs. This parameter is fixed at 2% on an energy basis in the current model, consistent with estimates in the literature; however, incorporating empirically derived data would provide greater resolution. Incorporating

more refined data for these various parameters may be expected to substantially narrow the confidence interval in the results, but it should not yield dramatically different estimates for the expected national average costs reported here.

Short of integrating plant-level data, aggregating coal plant data and biomass fuel supply estimates on a finer geographical basis (e.g., at the county level rather than the state level) could provide improved spatial resolution. However, interactions across regional boundaries, in terms of biomass supply, may become more significant and require explicit modeling.

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Chapter 2

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Chapter 3

Biomass with carbon capture and sequestration: Medium to long-term potential

Biomass resources are uniquely positioned at the intersection of industrial energy systems and the natural carbon cycle, embodying both solar energy and atmospheric carbon. The mitigation potential of biomass in these two distinct dimensions is reflected in the literature evaluating biomass as a (nearly) CO₂ neutral substitute for fossil fuels or as a means of offsetting industrial emissions by sequestering carbon in terrestrial ecosystems [1]. Yet there has been relatively little consideration of means to leverage this intersection or to optimize the mitigation potential of biomass across these dimensions. The more recent development of carbon capture and storage technologies (“CCS”), conceived as a means toward fossil fuel use without atmospheric CO₂ emissions [2], provides a new suite of opportunities for biomass-based mitigation. This technology may offer unique advantages and may enable a more integrated approach to biomass-based carbon mitigation.

CCS development has primarily aimed at decoupling fossil fueled energy systems from atmospheric carbon emissions. Integration with biomass energy technologies could provide a distinctly different benefit: generation of negative net carbon emissions as atmospheric carbon—fixed through photosynthesis—is captured and sequestered from the atmosphere for geologic timescales.

Section 3.1 provides background information regarding potential integration of biomass

energy systems with CCS, and characterizes certain concepts underlying the analysis in the balance of this chapter. Section 3.2 characterizes the various technological routes for integrating bio-energy systems with CCS. Section 3.3 describes a simplified engineering-economic model of biomass IGCC with CCS. Section 3.4 describes simplified engineering-economic models of biofuels production with CCS. Section 3.5 explores possible implications of a competitive environment for low carbon energy products using a simple top-down stochastic model to estimate energy costs with explicit accounting of uncertainty in key model parameters. Section 3.6 provides an integrated discussion of results from the analyses developed in this chapter.

3.1. Background

Biomass generally provides four routes for carbon mitigation: *in situ* sequestration by reforestation and conservation; remote sequestration by harvest and burial; substitution for fossil fuels; and substitution for fossil fuels with remote sequestration (“biomass-CCS”) [3, 4]. Only biomass-CCS can both provide low-carbon energy products and effectively remove carbon from the natural carbon cycle. As a result, biomass-CCS can offer the largest mitigation per unit biomass, or equivalently per unit land area, potentially important, given limited agricultural resources [5].

The ability to generate negative atmospheric emissions may also provide important benefits in achieving deep emissions reduction targets. Top-down estimates of the

economics of stabilizing atmospheric CO₂ at an effective doubling of pre-industrial concentrations without biomass-CCS suggest marginal mitigation costs could exceed 1,000 U.S. dollars per metric ton carbon mitigated ($\$ \text{tC}^{-1}$) [6]. These high marginal costs arise where *direct* mitigation is expected to be difficult, as in the transportation sector where the combination of mobile emissions sources and strong consumer performance preferences will likely drive up the cost of mitigation [7]. Alternatively, negative emissions from biomass-CCS, which effectively provide level mitigation costs across all sources, could offset some fraction of these emissions, providing *indirect* mitigation, at potentially lower cost. In this case (and depending on the regulatory framework), integration of CCS could improve the economics of bio-energy projects as internally-generated emissions offsets are sold to provide indirect mitigation of third-party carbon emissions.

The potential for indirect mitigation extends the scope of carbon mitigation with biomass and may provide cost-effective mitigation alternatives across the economy, fundamentally changing the economics of biomass-based mitigation. Further, negative emissions may provide a means to actively manage atmospheric carbon concentrations over the very long term. Negative emissions from biomass-CCS do not, however, offer a strict cap on mitigation costs since its costs must scale with the biomass supply curve, which may become steep if large-scale bio-energy crops compete for limited land resources. Environmental impacts may further constrain biomass mitigation potential [1]. However, the extraordinary heterogeneity of emissions sources provides many niches, and integrating CCS will extend the opportunities for biomass-based mitigation.

In order for CCS to be deployed at scales relevant to the management of anthropogenic carbon emissions, it must be technically feasible, economically dominant to other mitigation options, and be socially acceptable in the face of its risks to human health and welfare, public and private property, the environment, and the climate system. Climate risks, in particular, derive from the potential for widespread future leakage of CO₂ from storage systems [8]. Because CCS technologies reduce the conversion efficiency of energy systems, their implementation increases fuel use and CO₂ production on an energy output basis [2]. The implication is that total atmospheric greenhouse gas emissions could actually increase with widespread fossil CCS deployment and persistent storage system leakage. In this context, through its ability to actively remove CO₂ from the atmosphere, biomass-CCS could enable effective management of future emissions from leaking fossil CCS storage facilities, turning such emissions into an economic cost rather than an unavoidable source of environmental damage.

Separately, integrating CCS with bio-energy systems may be viewed as having somewhat lower risk than fossil-CCS because the efficiency penalty does not imply increased total emissions (relative to a business-as-usual scenario) if storage systems fail—biomass energy systems can be carbon neutral (or very nearly so) at worst, as discussed in Section 1.1. The magnitude of this risk reduction is likely (very) small, but it could plausibly allow biomass-CCS to garner increased support for early CCS deployments. Biomass-CCS deployments may provide a similar, and potentially larger, public perception benefit for the management of early CCS deployments by attracting support from environmental

groups who promote renewable energy and who may otherwise oppose CCS as a means to extend fossil fuel utilization.

To develop a better understanding of the potential role and importance of biomass-CCS, the possible technological routes to CCS are surveyed and three are evaluated in detail.

The first of these three routes is biomass integrated gasification combined cycle with CCS (BIGCC-CCS), for which a simplified engineering-economic model is presented of a feasible, though non-optimal, system. The model is based on previously published process models and associated component cost estimates for major subsystems [9-11].

The current analysis focuses on system integration including: identification of component technologies and integration points; design modification to facilitate integration; integrated process stream modeling; and integrated economic modeling.

The second and third routes that are evaluated represent production systems for two different biofuels: ligno-cellulosic ethanol and Fischer-Tropsch liquids (FT). Although the engineering-economic modeling techniques employed here are similar to those used for BIGCC-CCS, these analyses are conducted at a substantially higher-level and with increased reliance on previously published process design studies [12-14]. This more simplified modeling approach was adopted for two distinct reasons. In the bio-ethanol case, the subsystems affected by CCS integration are relatively minor components of production with minimal impact on the balance of the system; therefore, detailed modeling of all subsystem components is unnecessary and would not enhance understanding of the underlying technologies or system performance. In contrast, CCS

technologies would be tightly coupled with the production technologies in FT systems, implying that sophisticated optimization is required to evaluate this route to biomass-CCS. However, a relatively exhaustive analysis of biomass FT production configurations, with and without CO₂ separation, already exists, though that analysis does not consider capture and storage of the separated CO₂ [14].

In all cases, the current modeling activities are somewhat compromised by the fact that the systems modeled rely heavily upon proprietary technologies. As a result, technical and economic data for those technologies nearest to commercial deployment are not consistently reported. This challenge is not uncommon for technologies in active development, and as such, may be a more significant factor with respect to ligno-cellulosic ethanol model than for the BIGCC or FT models.

These analyses are followed by a discussion of conclusions that can be drawn with respect to the specific technologies evaluated and biomass-CCS more generally. The chapter ends with a brief discussion of areas for future work.

3.2. Routes to biomass-CCS

Three technological approaches are being advanced for fossil CCS: post combustion capture (PCC), where CO₂ is scrubbed from combustion exhaust streams; oxyfuel, where combustion occurs in pure oxygen and CO₂ is separated by condensing water from the

exhaust; and pre-combustion separation (PCS), where carbon is separated prior to combustion by gasification (of solid fuels), steam reforming, shift, and CO₂ scrubbing [2, 15, 16]. Note that PCS systems are uniquely flexible in their potential energy products, including gaseous fuels (e.g., hydrogen), liquid fuels (e.g., methanol), or electricity, and may have cost advantages relative to PCC for new plants due to lower energy requirements for carbon separation and higher conversion efficiencies of gas turbine and fuel cell power plants [15, 17].

Biomass has important similarities with fossil fuels (particularly coal), including conversion technologies and the range of energy products that can be generated, including dispatchable, base-load electricity as well as liquid and gaseous fuels. As a result, all three technological routes for CCS identified above could be applied to biomass energy systems, and biological processes, such as bio-ethanol fermentation, provide additional CCS opportunities for biomass. Figure 3.1 illustrates the major routes to biomass-CCS. Note that these major routes can be integrated in various ways, which may be important in the context of advanced bio-refineries currently favored by federal research and development programs [18, 19].

PCC or oxyfuel could be integrated with modern biomass boiler technologies or retrofitted to existing plants, though the small scale and low efficiency of existing biomass boilers would make this relatively inefficient. Alternatively, coal-fired power plants could be retrofitted to cofire biomass *and* incorporate CCS such that biomass carbon captured would more than offset incomplete capture of coal carbon [20]. With

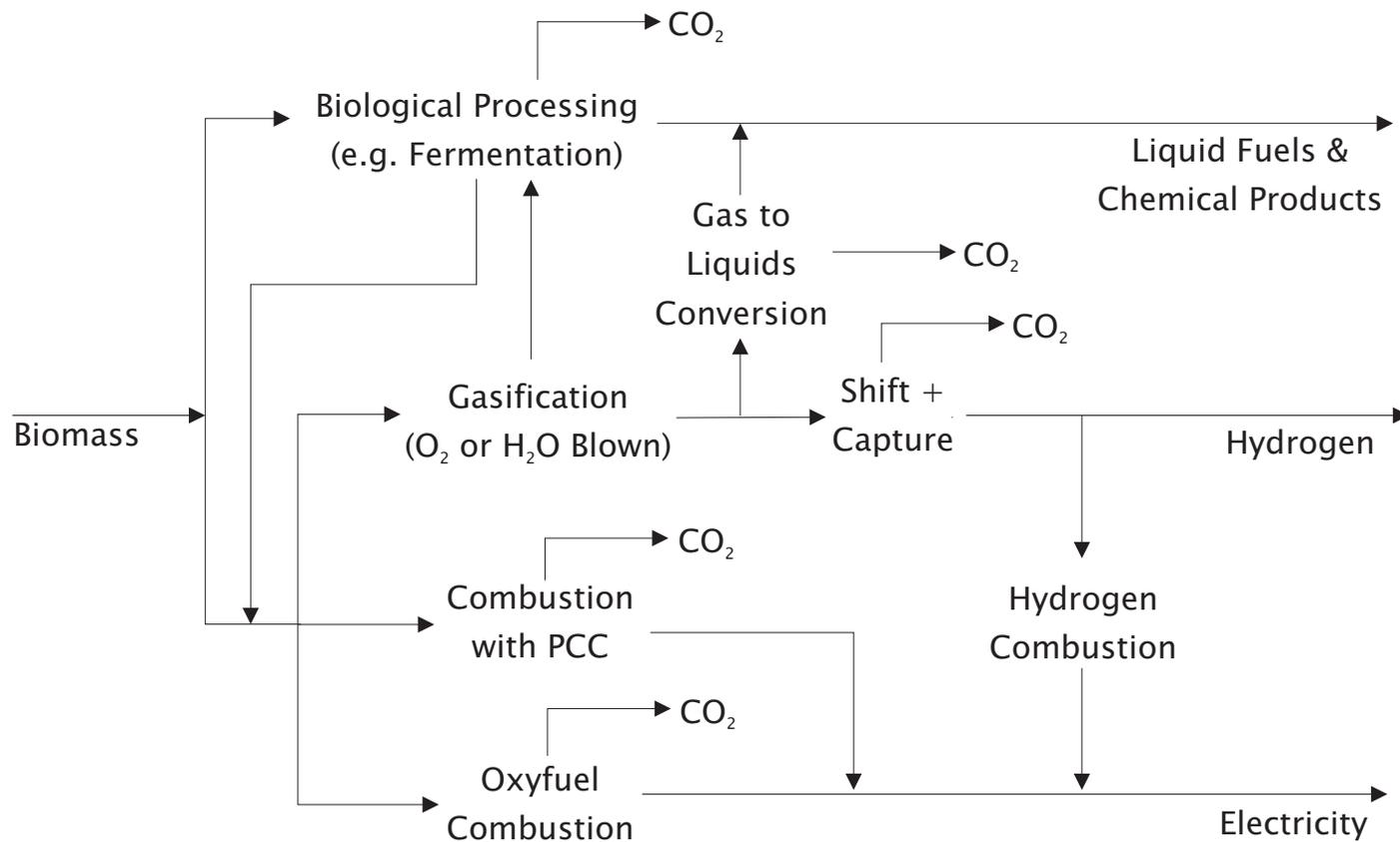


Figure 3.1. Routes to Biomass-CCS. The basic routes to biomass energy products with CCS include (from top to bottom) biological processing with capture of bi-product CO₂ to produce liquid fuels, biomass gasification with shift and CO₂ separation to produce hydrogen, and biomass combustion to produce electricity with CCS—either by oxyfuel or PCC routes. These routes can be combined or integrated by, for example, gasifying residual biomass from biological processes with CCS, biologically processing gasifier syngas into liquid fuels with CCS, converting gasifier syngas to liquid fuels with CCS, or by burning hydrogen-rich syngas to produce electricity with CCS, as in the BIGCC-CCS systems modeled here.

sufficiently stringent emissions controls, such a plant could be retrofitted to burn only biomass. The feasibility of this strategy would depend on emissions controls inducing both a low purchase price for unmodified coal-fired power plants and financial dominance of large negative emissions over potentially high fuel costs, as well as local access to very large biomass resources.

PCS could be integrated with modern and advanced biomass gasification technologies. Syngas dilution with atmospheric nitrogen largely eliminates the benefits of PCS in air-blown gasification systems; however, indirectly heated, steam-blown systems or oxygen-blown systems could effectively leverage PCS. While less developed than steam-blown systems, oxygen-blown biomass gasification has been demonstrated and can offer higher energy efficiencies and carbon capture rates, though somewhat less operating experience and economic data are available for these technologies [21, 22]. Alternatively, PCS could be integrated with IGCC plants that cofire coal and biomass. Cofired IGCC is in commercial operation in The Netherlands indicating that cofired IGCC-PCS is feasible [23-25]. Such systems may offer joint benefits from cofire (see Chapter 2) and IGCC.

CO₂ is produced as a byproduct to fermentation in equal molar proportions to ethanol. This nearly pure CO₂ stream is normally vented to the atmosphere, but could be captured and compressed for geologic storage; the implication is that nearly 35 Mt CO₂ is available for capture (at potentially very low costs) from fermentation of the 46 GL ethanol produced annually (as of 2005) [26]. Further, bio-ethanol production—particularly in ligno-cellulosic systems—generally also includes combustion—or

gasification and combustion—of waste biomass, providing further carbon capture opportunities, with additional cost [27].

3.3. Engineering-economic analysis of BIGCC with CCS

A simplified engineering-economic model is developed by integrating previously published ASPEN simulation results with associated cost estimates from several independent studies [9-11]. The cost and performance estimates are not intended to represent today's realities; rather, they reflect a prospective view assuming a design benefiting from at least 10 years of aggressive research and development to refine component technologies and reduce requisite contingencies. These assumptions are consistent with and incorporated directly from the underlying process simulation studies.

Four versions of the model are presented, three with CCS and a baseline without it. Additional design alternatives exist as do alternate component technologies; no optimization has been performed. In addition, alternate subsystem technologies, such as oxygen-blown gasification, could be applied to biomass fuels, with potentially higher energy efficiency and fuel carbon capture rates. Assessing the engineering-economic trade-offs of various systems for capturing CO₂ from biomass electricity or poly-generation systems is an important area for future research.

3.3.1. Process design

The model includes four subsystems: biomass gasification, syngas conditioning, carbon capture, and power generation, as illustrated in Figure 3.2. Gasification and syngas conditioning subsystems are modeled from two studies of the BCL/FERCO indirect gasifier [9, 10]; carbon capture and compression is incorporated from a design study of coal gasification with PCS [11]; the gas turbine combined cycle (GTCC) system is based on GE's H-class technology with minor modifications to accommodate hydrogen-rich fuel gas [28, 29].

Technology selection. Each subsystem could be modeled with several competing technologies that are either currently available or in late stages of development. Of these, biomass gasification has the most diverse options; this may be because supporting technologies for this subsystem are generally the least mature. A wide variety of biomass gasification technologies exist, as summarized in various reviews [21, 30-32].

Classification of gasification technology is primarily based on material flows (i.e., updraft, downdraft, fluidized bed, entrained flow, and several variants of these) and the gasifying agent (generally air, steam, or oxygen).

The primary criteria used to evaluate the compatibility of these alternatives for CCS applications were syngas composition, cold gas conversion efficiency, operational experience to date, data availability, and capital cost. The most limiting of these criteria

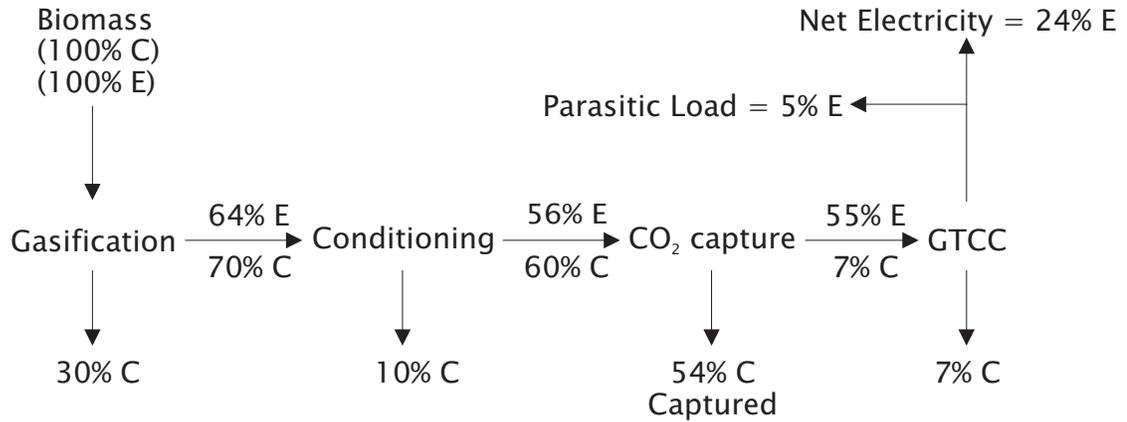


Figure 3.2. BIGCC-CCS subsystem schematic with carbon and energy flows. This schematic details carbon and energy flows between the four subsystems in the model version with carbon capture and syngas conditioning heated by burning syngas diverted directly upstream of the reformer. In this model version, roughly 10% of biomass carbon is emitted during syngas conditioning, and an additional 30% is emitted during char combustion, which provides heat for gasification and fuel drying. Rounding errors result in minor inconsistencies across the values in the figure.

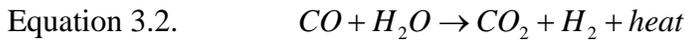
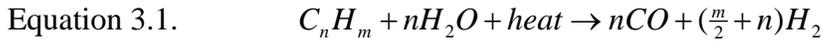
were syngas composition, operational experience to date, and data availability. Specifically, while operational experience to date is strongly dominated by air-blown systems, air-blown gasification yields syngas that is diluted with atmospheric nitrogen. This nitrogen dilution substantially reduces the inherent advantages of the PCS route to CCS by decreasing CO₂ partial pressures and increasing volumetric flows of the processes stream entering the capture system. Oxygen-blown gasification has been demonstrated with positive results in several technologies; however, both operational experience and data availability are generally limited. With this in mind, the BCL/FERCO gasifier was determined to be the best option for modeling the biomass gasification subsystem.

The BCL/FERCO system is unique because heat for gasification is provided indirectly by char combustion in a separate reaction vessel. Circulating sand provides heat transfer between the combustor and gasifier (Figure 3.3). This system avoids syngas dilution with nitrogen; however, roughly 30% of fuel carbon is emitted as char combustor flue gas. These losses are inherent to indirectly heated systems, and while they could be limited with design modifications (for additional cost), such modifications are not explored here. The BCL/FERCO system also appears to have relatively high throughput, high energy efficiency, and capital cost advantages relative to other biomass gasifiers [10]. Although the system is not currently in commercial use, a demonstration facility with a capacity roughly one sixth that modeled here is in operation at McNeil Station in Vermont [33].

It is noteworthy that development of biomass gasification technologies, including the BCL/FERCO system, has faced a variety of challenges due to *inter alia* certain fuel characteristics of biomass, as discussed in the reviews referenced above. For example, the fibrous nature of biomass can cause fuel feeding challenges, and the presence of certain compounds—including chlorine, sodium, and potassium—can cause agglomeration problems in fluidized beds. These issues, and others unique to biomass gasification, represent important factors in understanding the nature of opportunities for biomass IGCC; however, they have been the subject of substantial research and development activity and do not appear to represent fundamental barriers to deployment of biomass gasification systems. This is evidenced by ongoing advances in commercialization, which include deployment of dedicated biomass gasification systems, including the BCL/FERCO system modeled here, and systems co-gasifying biomass with coal [34].

Selection of syngas conditioning technology is largely driven by the syngas composition and characteristics. Generally speaking, however, there are three basic components: syngas cleaning to remove tar and particulates; steam reforming to convert CH_4 and higher hydrocarbons to H_2 and CO , by Equation 3.1 [9]; and gas-water shift to convert CO to H_2 and CO_2 , by Equation 3.2 [9]. Cleaning of biomass-derived syngas is generally assumed to be accomplished by a combination of cyclones and either hot-gas cleaning technology or a water scrubber. Hot-gas cleaning is considered to be superior in many applications due to the conservation of syngas heat; however, in spite of several years of research and development, its commercialization prospects remain uncertain. As a result, the syngas conditioning subsystem is modeled based on a water scrubber technology,

consistent with the original design study by Doctor et al.[9].



Technologies for steam reforming and gas-water shift are relatively mature and well understood. The steam reformer consists of catalyst-filled tubes, around which syngas is burned to heat the endothermic reactions [9]. Roughly 20% of CO is also converted to CO₂ by the gas-water shift reaction in the steam reformer as well. Because these reactions are exothermic with thermodynamics favoring shift at lower temperatures, the model includes two catalyst-filled shift reactors in series with heat recovery steam generation upstream from each. The model for these system components is based on the data in reference [9].

Several technologies are capable of capturing CO₂ for compression, transport and geologic storage. However, the dominant system for PCS applications, with its associated high CO₂ partial pressures, is physical absorption with glycol solvents such as Selexol [2, 11, 15, 35]. While absorption properties of commercial solvents are proprietary with limited public data available, there are several studies based on

generalized glycol solvent performance estimates in the literature. The carbon capture subsystem is based on the design study by Doctor et al.[11].

The power generation subsystem model is based on the GE H-class combined cycle gas turbine. This is the most efficient system marketed by GE, capable of 60% conversion efficiencies on a lower heating value basis (LHV) [29]. It is assumed that comparable technology will be available at 100 MW_e scale within the time horizon of this analysis, although it is currently not available at scales below 400 MW_e. Modifications to support combustion of hydrogen-rich fuel gas, as described by Audus et al.[28], are also assumed.

These assumptions are optimistic; hydrogen fuel conversion in an H-class system may not be economically achievable at 100 MW scale within the 10-year time horizon of this analysis. The performance of GE's 7FA or 7FB combined cycle gas turbines, which have conversion efficiencies between 56 and 58% (LHV), may be reasonable reference points in understanding the importance of these modeling assumptions [36]. Reducing the power generation subsystem conversion efficiency to 58% would reduce net plant efficiencies by around 1% (HHV) and increase specific capital costs by around 4%, depending on the system configuration. The effects of reducing conversion efficiency to 56% are roughly twice as great.

Process integration. An integrated design is modeled from process blocks in the above-mentioned studies with minor modifications to balance stream compositions, pressures,

temperatures, and flow rates so as to conserve heat, chemical energy, and mass. These modifications include (i) scaling of component technologies, (ii) substitution of process heat sources and uses, (iii) addition of supplemental generation capacity, and (iv) addition and heat duty modification of heat exchangers. Transformation from input to output streams for individual process blocks are linearly scaled from the original subsystem analyses (e.g., CH₄ in the steam reformer output is ~41% of the CH₄ reformer input based on the design study by Mann [9]).

Integration of gasification with syngas conditioning is addressed in an NREL study by Mann [9]; however, that study included sophisticated integration of gasification, conditioning, and a pressure swing adsorption (“PSA”) system to produce high purity hydrogen. The PSA is replaced with a glycol scrubber in the model, which is more cost effective, given lower purity requirements for CCS applications. Several modifications, described below, were required to isolate the gasifier, reformer, and shift reactors from the PSA and balance of plant.

A steam dryer assembly from a more recent study of the BCL/FERCO system for the Weyerhaeuser Corporation by Raymond et al.[10], is substituted for the rotary dryer in the NREL study. Both use char combustor exhaust for biomass drying, but the steam system also provides gasifier steam, freeing up downstream process heat. The steam dryer has efficiency and emissions benefits, as well. Syngas composition and production rates from the Weyerhaeuser study are integrated throughout downstream process blocks for consistency.

The gasifier converts ~23% of input carbon to methane and higher hydrocarbons. Addition of steam reforming prior to water-gas shift improves the carbon capture rate by shifting some of the methane to CO₂, CO and H₂, but raises costs and lowers energy efficiency, as discussed below (see Table 3.2 below). Two alternate designs are developed for providing heat for steam reforming. In both cases, the heat requirements were estimated by balancing the heat required for reform (estimated by the change in enthalpy of formation and sensible enthalpy across the reformer) with the heat available from combustion (estimated by the lower heating value of syngas minus the change in sensible enthalpy of combustion products to 100 °C above the syngas output), assuming 98% heat transfer efficiency throughout. The simplest design burns ~12% of unreformed syngas diverted directly upstream from the reformer. However, combustion products are vented to the atmosphere decreasing carbon available for capture. The second alternative is designed to minimize carbon losses by burning hydrogen-rich fuel gas diverted after carbon separation. This approach does limit carbon, increasing the carbon capture rate by ~13%. However, the fraction of syngas diverted to provide reformer heat increases to ~24% due to the combined effect of increased reformer throughput (100% of the syngas compared with 88%) and increased heat losses from moisture in the combustion products of the hydrogen-rich fuel gas. The net effect is a substantial reduction in net plant efficiency. This option also has higher total capital costs as the syngas conditioning and carbon capture subsystems must support 13% greater throughput than if the heat were derived from syngas diverted upstream of the reformer.

A final modification to gasification and syngas conditioning subsystems is the application of available process heat to preheat the fuel gas upstream from the gas turbine and raise steam for the reformer, shift reactors, fuel gas humidification, and supplemental power generation. In contrast, the NREL study took an economic credit for steam as a co-product. Figure 3.3 presents a schematic of the gasification and syngas conditioning subsystems.

The CO₂ capture sub-system is incorporated without modification from the design by Doctor et al. [11]. It is integrated after the low temperature shift heat recovery steam generator (LT HRSG in Figure 3.3), where the modeled stream composition is nearly identical to that in the original design, as shown in Table 3.1. Minor pressure and temperature differences in the originally published process streams are addressed by incorporating additional compression and by modifying the modeled heat rate of the heat exchanger directly upstream from the capture system. The flow rate difference in the originally published streams is primarily addressed by scaling up the gasifier and syngas conditioning sub-systems; however, to avoid comparisons across disparate capacities, which would have strong implications due to economies of scale, alternate system configurations are modeled with the same thermal capacity and downstream equipment is re-scaled accordingly. Separated CO₂ is compressed to 145 bar for pipeline transport while the lean solvent is compressed, refrigerated, and recycled [11, 35].

The GTCC system incorporates fuel gas humidification of 0.6 kg steam per kg fuel by blending the fuel with steam at the same pressure [28]. A net conversion efficiency of

60% (LHV) is assumed for the GTCC, consistent with current H-class technology [29].

Figures 3.4, 3.5, 3.6, and 3.7 provide process block diagrams for each version of the model. Associated flow stream data for each model version are provided in Appendix C.

Table 3.1
Comparison of modeled syngas streams

Stream parameter	Conditioned Syngas (CCS _{NR})	Conditioned Syngas (CCS _{R,SG})	Conditioned Syngas (CCS _{R,FG})	Conditioned Syngas [9]	Glycol system input [11]
H2 [% mol]	42%	61%	61%	62%	58%
CO2 [% mol]	39%	35%	35%	34%	37%
CH4 [% mol]	11%	3%	3%	3%	4%
CO [% mol]	3%	1%	1%	1%	0.4%
H2O [% mol]	0%	0%	0%	0.1%	0%
N2 [% mol]	0%	0%	0%	0.08%	0.3%
NH3 [% mol]	0%	0%	0%	0.01%	0.2%
S ^a [% mol]	0%	0%	0%	0.04%	0.03%
Ar [% mol]	0%	0%	0%	0%	0.6%
Flow rate [Mmol/hr]	3.8	5.2	6.1	2.6	5.3
Temperature [°C]	13	13	13	24	13
Pressure [MPa]	3.1	3.1	3.1	2.6	3.1

^a includes H₂S, COS, and SO₂

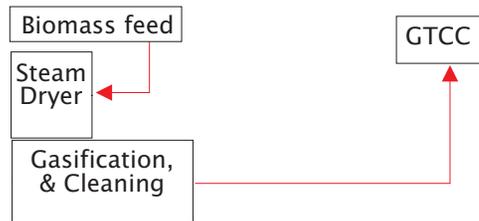


Figure 3.4. BIGCC process block diagram

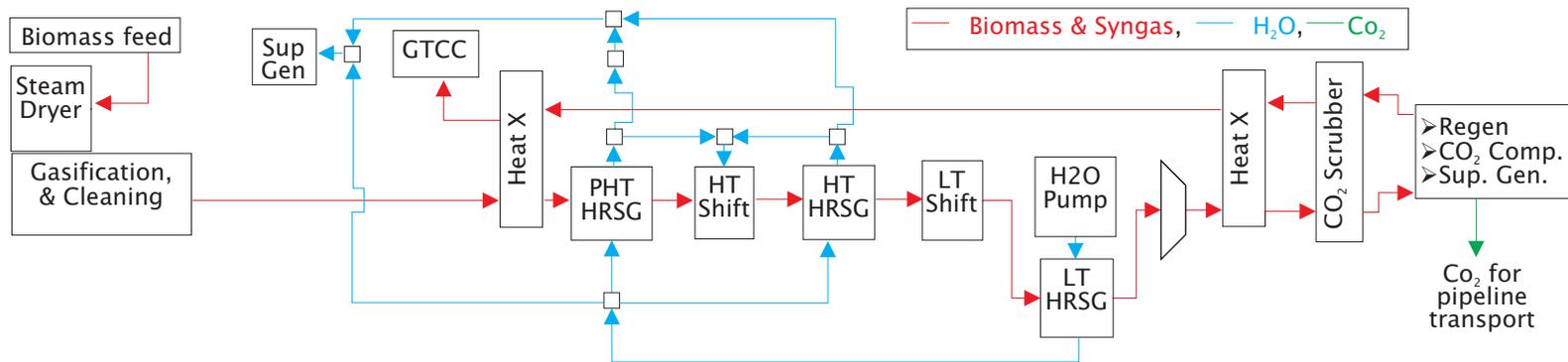


Figure 3.5. BIGCC-CCS_{NR} process block diagram

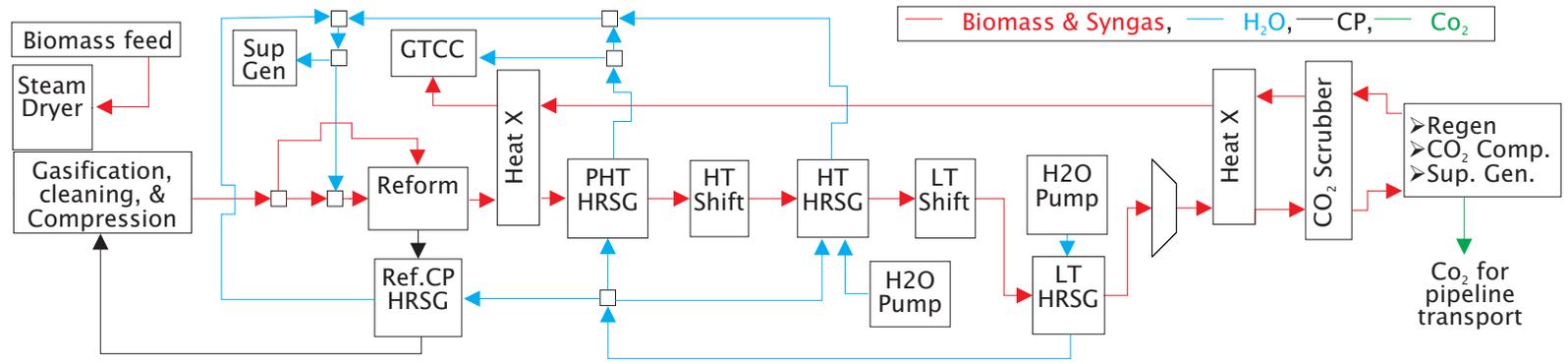


Figure 3.6. BIGCC-CCS_{R,SG} process block diagram.

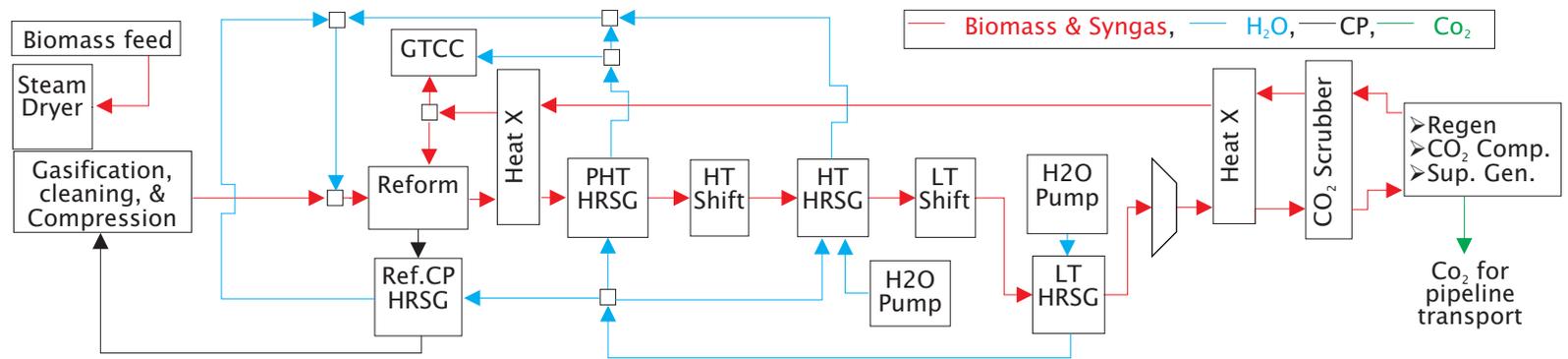


Figure 3.7. BIGCC-CCS_{R,FG} process block diagram.

3.3.2. Economics

The economic model is consistent with estimates and assumptions in the original design studies. Cost estimates for components in the gasification and syngas conditioning systems are developed from those in the NREL and Weyerhaeuser studies [9, 10]. Cost estimates for the carbon capture system are from those by Doctor et al. [11]. All capital cost scaling is calculated using scaling factor of 0.7 (component costs are assumed to be proportional to the equipment size raised to the 0.7 power).

Capital costs are converted to year 2000 dollars using the Component Cost Index for Chemical Processes. To estimate the total capital requirement economic assumptions for contingencies and other allocations from individual studies were applied to their respective components. The total capital requirement for the GTCC system is assumed to be \$550 per installed kW_e.

Non-fuel operation and maintenance cost estimates are also developed from the original literature [9-11]. Cost drivers adapted from those studies include labor, consumable material (catalysts, sorbent, etc.), ash and sand disposal, maintenance, insurance and local taxes, royalties, and other operating costs. A capacity factor of 0.8 is assumed for all calculations. A CO₂ sequestration cost of \$10 per ton is assumed, to pay for pipeline transport to an appropriate storage facility, final compression, and geological sequestration [16, 37]. Initial compression for pipeline transport is modeled within the carbon capture subsystem [11, 35].

The economic models for each version are provided in Appendix C.

3.3.3. Results

Summary cost and performance results are presented in Table 3.2 for three biomass IGCC systems *with* carbon capture—BIGCC-CCS_{R,FG} with steam reform heated using hydrogen-rich fuel gas diverted downstream of carbon capture, BIGCC-CCS_{R,SG} with steam reform heated using syngas diverted upstream of the reformer, and BIGCC-CCS_{NR} with no steam reform—as well as for the base case system *without* carbon capture, BIGCC. Summary results are also provided for a system with modified modeling assumptions based on published pilot plant performance data [33], BIGCC-CCS_{R,SG,UD}, as discussed below. All systems assume a thermal capacity of 444 MW_{th}, equivalent to roughly 2,100 bone-dry tons per day. Net generation for the systems are 91, 108, 123, 149, and 91 MW_e, respectively and carbon capture rates—equal to the fraction of fuel carbon captured—are 62%, 54%, 44%, 0%, and 46%, respectively. Not surprisingly, net generation and carbon capture rates scale in opposite directions (ignoring for now the system with a revised modeling basis) as increasing carbon capture is associated with decreasing thermal efficiency and increasing parasitic load. This efficiency penalty, combined with increasing capital requirements, causes specific capital costs (\$ kW⁻¹) and electricity costs to increase with carbon capture rate, as indicated in Table 3.2. This trade-off between cost and carbon capture in the three CCS cases provides an example of

Table 3.2
Summary cost and performance results for biomass IGCC models

Model	BIGCC	BIGCC-CCS _{NR}	BIGCC- CCS _{R,SG}	BIGCC- CCS _{R,FG}	BIGCC- CCS _{R,SG,UD}
<i>Technical</i>					
Thermal capacity [MW _{th}]	444	444	444	444	444
Gross Generation [MW]	160	144	131	116	112
Parasitic load [MW]	10	21	23	24	21
Net generation [MW]	149	123	108	91	91
Net conversion efficiency [% HHV]	34%	28%	24%	21%	20%
Carbon capture rate [% input Carbon]	0%	44%	54%	62%	46%
Specific carbon emissions [kgC/kWh]	0.00	-0.14	-0.20	-0.27	-0.20
<i>Economic</i>					
Total capital requirement [M\$2000]	\$ 153	\$ 181	\$ 183	\$ 176	\$ 147
Annual O&M cost [\$M/yr]	\$ 12	\$ 13	\$ 13	\$ 13	\$ 13
Specific capital cost [\$W]	\$ 1.03	\$ 1.47	\$ 1.70	\$ 1.93	\$ 1.62
Specific O&M [\$kW yr]	\$ 100	\$ 131	\$ 151	\$ 177	\$ 177
Cost of electricity ^a [\$kWh]	\$ 0.055	\$ 0.077	\$ 0.090	\$ 0.106	\$ 0.099
Mitigation cost ^b [\$tC]	\$ 84	\$ 112	\$ 127	\$ 141	\$ 147

^a Cost of electricity is calculated as the sum of capital costs (which are amortized over 20 years at 10% interest) non-fuel operating and maintenance costs, sequestration costs (which are assumed to be 10 \$/tCO₂), and fuel costs (which are assumed to be 50 \$/t or 2.5 \$/GJ biomass delivered). ^b Mitigation costs are calculated as the difference in electricity costs divided by the difference in carbon emissions for each biomass technology relative to PC coal; PC coal is defined to have net efficiency, fuel carbon intensity, fuel cost, non-fuel operation and maintenance cost, and specific capital cost - amortized over 20 years at 10% interest - of 40% (HHV), 24.1 kgC/GJ, 1 \$/GJ, 0.8 c/kWh, and 1,200 \$/kW, respectively.

how CCS deployment will likely be dominated by economic optimizations rather than fundamental technological constraints.

The economic implications of these results are ambiguous, absent comparison to competitive electric sector technologies. Figure 3.8 provides this context by plotting the cost of electricity for the systems modeled here as well as for conventional coal and natural gas technologies as a function of carbon price.

Note that carbon emissions are computed on an operating basis only and with the assumption that the biomass feedstock is delivered to the plant on a carbon neutral basis. The calculations would be substantially different if a life-cycle analytic approach had been adopted, which would have accounted for indirect emissions from, *inter alia*, fossil inputs to agricultural production, biomass transport, plant and equipment construction, and labor. It is, however, not clear what effect this additional accounting would have on the results. The effect on mitigation costs is uncertain because they are defined on a relative basis and analogous emissions accounting would have to be incorporated into emissions estimates for the fossil fuel baseline system. The effect on mitigation potential of biomass (on specific or total bases) is uncertain because, as discussed in Section 1.1, while life-cycle emissions of ligno-cellulosic energy systems are generally thought to be low [38], a life-cycle assessment of the BCL/FERCO IGCC system found that the sign of life-cycle GHG emissions hinges on assumptions regarding, *inter alia*, soil carbon sequestration rates—the rate at which biomass carbon accumulates in the soil during cultivation [39]. Systematic analysis of these issues is beyond the scope of this thesis.

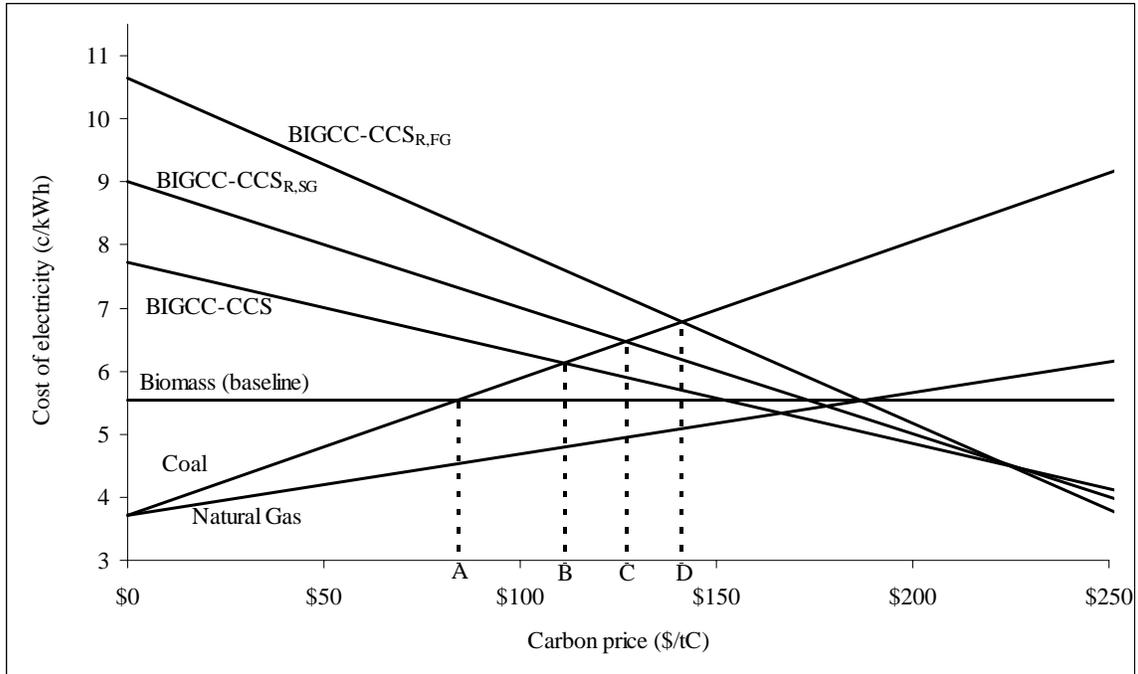


Figure 3.8. Cost of electricity as a function of carbon price. Electricity cost curves are plotted for each version of the BIGCC model described. Curves for pulverized coal and natural gas turbine combined cycle are provided as conventional baseline technologies. Parameters for these fossil systems have been deliberately set to yield equal electricity costs at zero carbon price, specifically, fuel costs, fuel carbon intensities, HHV conversion efficiencies, and capital costs are set to 1.00 and 3.46 \$/GJ, 24.1 and 13.5 kgC/GJ, 40% and 50%, and 1.2 and 0.55 \$/W for coal and natural gas, respectively. Slopes in the figure are proportional to specific carbon emissions [tC/kWh], with negative slopes resulting from negative net emissions for Biomass-CCS systems. Mitigation costs are defined by the carbon price at which the curve for each mitigation technology intersects with that of the baseline technology. Assuming coal as the baseline, mitigation costs are defined by carbon prices labeled A, B, C, and D.

Electricity costs for the two fossil fuel technologies are low with zero carbon price, around 3.7 cents per kWh (note that the parameters have been adjusted to yield equal electricity costs absent carbon constraints to simplify the figure). However, fossil fuel electricity costs increase in proportion to their fuel carbon intensity divided by their net efficiency. As a result, costs increase much faster for coal than natural gas. The cost of biomass electricity without CCS, the conventional view of biomass electricity, is higher than that of fossil fuels with zero carbon price, but has a slope of zero, reflecting the general balance in carbon emissions and CO₂ uptake during biomass production. Fossil emissions associated with biomass production, harvest, and transport are generally small—representing fossil energy less than 5% of biomass energy—and are ignored here [40]. As an aside, note that this curve is broadly similar to those expected from fossil fuel technologies with CCS [8]. Finally, the three biomass-CCS cases have electricity costs substantially higher than the base line biomass technology due to their higher capital costs and lower net efficiencies. However, their costs decrease in proportion to their carbon capture rate, reflecting an economic credit for negative carbon emissions. As carbon prices increase, biomass-CCS becomes increasingly cost effective and with sufficiently high prices (~200 \$ tC⁻¹) biomass-CCS becomes the least-cost electric sector technology.

Mitigation costs can be read directly from Figure 3.8 as the carbon price where electricity costs from a particular mitigation technology equals that of the conventional baseline generation technology. From the case illustrated, the mitigation costs are calculated as 84, 112, 127, and 141 \$ tC⁻¹ for the cases BIGCC, BIGCC-CCS, BIGCC-CCS_{R,SG}, and

BIGCC-CCS_{R,H}, respectively—assuming pulverized coal as the conventional baseline technology. These results should not be interpreted too precisely, due to the simplified modeling techniques. However, they do indicate mitigation costs for BIGCC-CCS options to be somewhat higher than those expected from fossil fuel systems with CCS [2, 8]. While these economics will likely improve with process and component technology optimization, the current results suggest it is unlikely that BIGCC-CCS will substantially reduce mitigation costs from biomass or in the electric sector more generally. This is at least partially because benefits from process and component technology optimization for BIGCC-CCS will likely be mirrored in fossil-CCS options. However, even without substantial improvements, biomass-CCS will likely be cost-competitive for mitigation beyond the electric sector (via emissions offsets)—where, as discussed above, costs may exceed 1,000 \$ tC⁻¹—substantially reducing total costs for achieving deep emissions reductions targets. In this context, biomass-CCS may eventually face competition from technologies for direct capture of CO₂ from the air. However, such systems are substantially less proximate and more uncertain than biomass-based options.

Pulverized coal combustion (PC coal) technology is assumed as the baseline for mitigation cost calculations. As shown in Figure 3.8, however, switching from PC coal to combined cycle natural gas turbines (GTCC) could provide zero cost mitigation, and would push the mitigation cost of biomass up to nearly 200 \$ tC⁻¹—with or without CCS. However, this interpretation hinges on the cost of natural gas. Natural gas prices are historically variable, and estimates of future prices are highly uncertain. The natural gas price used here, 3.46 \$ GJ⁻¹, is optimistic given current prices and futures market

expectations [41, 42]. In addition, a wholesale conversion of the electric sector to natural gas, implied by the interpretation outlined above, would dramatically increase demand and drive up fuel costs. Under the modeling assumptions used here, GTCC is *never* the least cost technology if the natural gas price were to increase by 40%, which may still be optimistic, in light of recent price projections [41]. Moreover, uncertainty about gas prices may encourage power companies to maintain significant coal generation in their portfolios as a hedge against natural gas price fluctuations. Of course, uncertainty about future carbon constraints will weigh against building new PC coal, but not against maintaining existing units. In short, while GTCC is very important and is included here as a point of reference, PC coal is judged to be the appropriate baseline for mitigation cost estimates.

The delivered cost of coal is assumed to be 1 dollar per GJ (\$/GJ) based on relatively stable historical costs. However, the average price paid by electric utilities has climbed from 1.14 \$/GJ in 2000 to 1.60 \$/GJ in 2006 [43]. It is plausible that future prices will remain near their recent highs, increase further, or decrease back toward their more historic levels. In general, increasing coal prices reduce mitigation costs for all biomass technologies. However, the magnitude of this effect is different for each technology, depending on the relative slopes of the cost curves in Figure 3.8, with a smaller mitigation cost reduction for technologies having more negative slopes. The result is that while increasing coal costs increase the competitiveness of BIGCC-CCS options, they tend to decrease their attractiveness, relative to BIGCC without CCS.

Finally, recent experimental data from the Battell/FERCO designed pilot plant facility in Burlington, Vermont, show that the syngas composition from the pilot plant matches closely with that modeled here and that this composition is relatively insensitive to variations in fuel type, moisture, or feed rate [33]. However, the data do suggest two possible updates to the model presented here. First, the maximum capacity of the pilot plant has been demonstrated to be 75% greater than the design capacity. This suggests a potential 32% reduction in the gasifier's specific capital cost [$1-(1/1.75)^{0.7}$] relative to the current modeling assumptions. Second, although the cause is unclear, the carbon conversion rate of the pilot plant has been close to 60% compared with nearly 70% currently modeled. This reduced carbon conversion would translate into decreased net plant efficiency, decreased carbon capture efficiency, and increased specific capital costs. However, the source of discrepancy between these results and those previously modeled is unclear as the pilot plant experience reflects results from extensive parametric testing rather than optimized plant operations. It is therefore not obvious which modeling basis provides a more accurate indication of the system's long-term performance. However, summary results incorporating the pilot plant performance are presented in Table 3.2, as discussed above.

3.4. Engineering-economic analysis of biofuels with CCS.

Biomass resources can be used to produce several types of liquid fuels—ethanol, methanol, Fischer-Tropsch liquids, and bio-diesel—and have variously been considered

for their potential contributions to energy security, air quality, and anthropogenic climate change. CCS technologies could be integrated with the production systems for many of these biofuels—specifically, gasification systems in methanol, ethanol and Fischer-Tropsch liquid (FT) production, and fermentation processes in bio-ethanol production. However, maximum theoretical carbon capture rates are inherently lower for biofuels compared with electricity or hydrogen production due to the carbon remaining in the liquid fuel product.

Methanol (and the derivative MTBE) were once used widely in the U.S. as a gasoline oxygenate. However, concerns about toxicity and groundwater contamination led to substantially reduced utilization in favor of other reformulated gasoline blends [44]. Biodiesel, derived from plant oils, is available in limited quantities within certain markets. No judgments are made regarding the relative merits of these potential biofuels; however, these fuels are not considered further in this analysis.

Bio-ethanol is widely used in the US as a gasoline oxygenate, with air quality and performance benefits, and makes important contributions to transportation fuel supplies in several international markets and [45, 46]. Its use in the U.S. has expanded substantially with the decline of MTBE [45]; however, U.S. production is dominated by corn-fed fermentation processes, which provide only small climate benefits due to fossil-intensive inputs to production [38]. In contrast, sugar-based ethanol production systems, which are more prevalent internationally, can have substantially lower fossil inputs, as can systems that convert ligno-cellulosic feedstock, such as wood, switchgrass, and

agricultural or forestry residues [38, 47]. Ligno-cellulosic ethanol production systems are currently in development and may be available at commercial scale within the 10-year horizon adopted throughout this analysis [12, 45].

FT systems are used to convert syngas to liquid hydrocarbons. Since their initial development, these systems have made important contributions to fuel supplies where demand is isolated from supply (e.g., Germany in the first half of the century and South Africa) [48, 49]. Recent interest in FT systems has been motivated by environmental and energy security benefits, as well as the large amount of natural gas reserves designated 'stranded'. This last factor, in particular, has precipitated development of a commercial project in Malaysia by Shell [24, 50, 51]. Biomass-derived FT has not been developed, but has recently received some attention in the context of bio-energy technologies to mitigate climate change [14, 51-53].

To better understand the potential and implications of biomass-CCS in biofuel applications, simplified models are developed to characterize ligno-cellulosic ethanol production and biomass-derived FT liquids. In both cases the models herein rely heavily on previously-published design studies—Wooley et al.[12] and Aden et al.[13] for ethanol and Hamelinck et al.[14] for FT liquids. The current analysis only considers the potential for CO₂ capture from process streams as they were modeled in the original design studies; no new contribution is made with respect to the production systems themselves. Separate studies have been published evaluating sugar-cane ethanol and biomass FT systems with CCS [27, 53]; however, direct comparison with the current results is

confounded by the specific results data provided in those analyses.

3.4.1. Modeling basis: Ligno-cellulosic bio-ethanol with CCS

Detailed designs for a ligno-cellulosic bio-ethanol production have been published as part of a research program sponsored by the United States Department of Energy [12, 13].

The design by Wooley et al.[12] converts wood to ethanol and a small amount of surplus electricity; Aden et al.[13] provide a follow-up analysis of a system tailored to utilize corn stover feedstock. Detailed process descriptions along with estimates of costs, process stream flow-rates and compositions are provided in these original design studies.

The original results are adapted here to facilitate modeling of, and simplified comparison with, analogous systems that integrate CCS. Specifically, three model variations are presented for each design: one with capture only from fermentation off-gases (BE-CCS_{OG}); one that adds CCS from waste biomass combustion flue gases (BE-CCS_{OG+FG}); and a baseline system without CCS that simply adapts the results from Wooley et al.[12] and Aden et al.[13] to support internally consistent comparisons (BE). Note that results from Wooley et al.[12] are adapted to reflect an ethanol production rate of 81 gallons per ton biomass (g/t), up from the published baseline of 68 g/t, based on the estimate presented in that analysis of what should be achievable within 10 years.

There are several important differences between these two design studies, including sourcing of certain inputs to production (e.g., enzymes produced on site in the design by

Wooley et al.[12] are purchased from third party suppliers in the design by Aden et al.[13]) and the net conversion rate (gallons ethanol per ton biomass). These differences lead to systematically different results in terms of total ethanol production cost, with those from the design by Aden et al.[13] being generally lower than those from the design by Wooley et al.[12]. The implications of these differences for net carbon emissions (from energy consumption by third party suppliers) have not been evaluated, and no correction has been made with respect to net carbon emissions.

In both studies, pre-processing converts cellulosic feedstock components into sugars for fermentation. Fermentation then converts these sugars to ethanol, producing CO₂ as a byproduct. Importantly, the carbon content of this stream is proportional to ethanol production, so more efficient processing increases the fraction of feedstock carbon available for capture. Capture of this CO₂ requires only ducting the fermentation off-gas vent to compression for pipeline transport.

Large fractions of feedstock biomass cannot be converted into ethanol. This is due to limits on the biological processes of fermentation—specifically in terms of the compounds that can be digested by the organisms responsible for fermentation. This biomass is typically burned with other system waste streams to supply process heat and electricity.

Two model versions (one based on each underlying design study) include CCS integration with combustion of the waste biomass streams—maximizing the carbon capture potential of bio-ethanol systems. In both cases, carbon capture is accomplished

with PCC systems using amine-based solvents. Such systems are generally less efficient than PCS systems using glycol-based solvents, as previously discussed. Waste biomass gasification followed by PCS carbon separation is likely feasible; however, reliable performance data are not generally available for biomass gasifiers operating on blended input streams similar to those in the ligno-cellulosic ethanol production systems. Uncertainty in gasifier performance dominated the decision to model carbon capture based on PCC technologies.

Surplus electricity—beyond that necessary to power system components—is generated in both of the original designs. In both cases, this surplus is assumed to be sold to the grid. As a result, in all but one case, the increased power required for CO₂ capture and compression only reduces revenues from these power sales. However, additional power must be purchased to support CCS capture and compression in the BE-CCS_{OG+FG} model based on the design by Wooley et al.[12]. Carbon emissions from this consumption are estimated from the average US CO₂ emissions factor from the electric sector (calculated by dividing US carbon emissions from electricity generation by total generation [54, 55]), and net power flows to and from the grid are valued at the same rate (see Table 3.3).

The economic models for ligno-cellulosic ethanol production are adapted from the work by Wooley et al.[12] and Aden et al.[13]. Capital costs, O&M costs, and power requirements for CO₂ compression are adapted from McCollum et al.[37] and Metz et al, 2005 [2]. Capital costs and power requirements for amine-based CO₂ capture are adapted from Metz et al, 2005 [2]; O&M costs are defined as a fixed percentage of

capital costs, as defined in Table 3.3.

Table 3.3
Biofuel modeling assumptions

Model parameter	Value	Ref.
Capacity factor	0.9	[12-14]
Discount rate	0.1	
Economic life [yrs]	20	
Currency conversion [\$ Euro ⁻¹]	0.88	[14]
Value of electricity import (export) [cents kWh ⁻¹]	4	
Emissions of electricity import (export) [tCO ₂ MWhr ⁻¹]	0.58	[54, 55]
CO ₂ transport & storage fee [\$ tCO ₂ ⁻¹]	10	[2, 37]
CO ₂ capture heat requirement [GJth tCO ₂ ⁻¹]	3.3	[2]
CO ₂ capture electricity requirement [GJe tCO ₂ ⁻¹]	0.33	[2]
Scale basis for capture capital cost [tCO ₂ hr ⁻¹]	355	[2]
Cost basis for capture capital cost [\$2000M]	210	[2]
Capital cost scaling factor	0.7	
CO ₂ capture O&M cost [fraction of capital cost]	0.04	
CO ₂ compression electricity requirement [GJ tCO ₂ ⁻¹]	0.4	[2, 37]
CO ₂ compression capital cost	See Appendix D	[37]
CO ₂ compression O&M [fraction of capital cost]	0.04	[37]
Delivered biomass fuel price [\$ t ⁻¹]	50	
Gasoline emissions factor [tC GJ ⁻¹]	0.018	[54]

3.4.2. Modeling basis: Fischer-Tropsch liquids with CCS

Hamelinck et al.[14] evaluate production of FT liquids from biomass using a coupled process simulation and economic model. The model includes subsystems for feedstock handling and pretreatment, gasification, syngas cleaning and conditioning, FT synthesis, optional recycle of FT synthesis off-gas, heat and power generation from FT synthesis offgas, and product recovery and upgrading; several configuration options are described

for each subsystem. Hamelinck et al.[14] evaluate the technical and economic performance of 55 plausible configurations—many more are feasible from the described configuration options but are eliminated based on logical arguments. The primary objectives of their analysis include understanding the likely performance of biomass FT liquids production in the short and medium term (including feasible product selling prices), and identifying preferable configurations to inform research and development priorities and potential development pathways.

Hamelinck et al.[14] describe CO₂ as inert to the FT process, but note that its presence in FT reactor input decreases the partial pressures of primary reactants and therefore decreases conversion rates [14]. Therefore, three of their 55 model configurations include CO₂ separation from the syngas upstream from the FT reactor using glycol solvents (e.g., Selexol). However, because it is the performance impact of syngas composition that motivates the modeled CO₂ separation (rather than the potential for negative atmospheric emissions), the resulting CO₂ stream is vented to the atmosphere and *not* compressed for pipeline transport and geologic storage. Hamelinck et al.[14] conclude that, although CO₂ separation does improve FT synthesis conversion rates, this benefit is offset by the additional capital and operating costs required for glycol separation, eliminating any potential reduction in the product selling price [14].

Preferred system configurations and their associated conclusions would likely have been different had Hamelinck et al.[14] valued potential negative carbon emissions.

Additional configurations may have been considered if negative emissions were valued,

including, for example, those with CO₂ separation from FT synthesis off-gas streams prior to combustion. To begin to understand the potential performance of FT-CCS systems, the published results for configurations with CO₂ separation are adapted to incorporate compression for pipeline transport and geologic storage. The results for the three configurations without CO₂ separation having the lowest FT production costs are also adapted to enable direct comparisons. One dimension of the analysis by Hamelinck et al.[14] was to consider scale effects on production cost; only configurations at 400 MW_{th} scale are considered here; this is the dominant scale evaluated in their analysis and is consistent with the scales assumed for the other technologies described herein.

The economic model by Hamelinck et al.[14] is published in 2002 Euros. As necessary, they converted costs developed in US dollars to Euros by setting 1 €₂₀₀₂ equal to 0.88 US\$₂₀₀₂. This rate is used here to convert their results back to US dollars.

Capital costs and power requirements for CO₂ compression are adapted from Metz et al, 2005 [2] and McCollum et al.[37]. Modeling assumptions underlying all biofuel models are provided in Table 3.3.

3.4.3. Results.

Summary results for the biofuel models are provided in Table 3.4. In the ligno-cellulosic ethanol models, capturing CO₂ in fermentation off-gases allows generation of negative

Table 3.4
Summary bio-fuel modeling results

Design basis												
Bio-fuel Version ^a	Ethanol Base ^b	Ethanol OG	Ethanol OG+FG	Ethanol Base	Ethanol OG	Ethanol OG+FG	FT Base-A	FT Base-B	FT Base-C	FT CCS-A	FT CCS-B	FT CCS -C
Reference	[12]	[12]	[12]	[13]	[13]	[13]	[14]	[14]	[14]	[14]	[14]	[14]
Engineering												
<i>Scale</i>												
Feed rate [dry t hr ⁻¹]	83	83	83	83	83	83	72	72	72	72	72	72
Feed rate [MW]	463	463	463	416	416	416	400	400	400	400	400	400
<i>CO₂ capture</i>												
Captured from fermentation [tCO ₂ hr ⁻¹]	0	21	21	23	23	23	0	0	0	0	0	0
Captured from flue gas [tCO ₂ hr ⁻¹]	0	0	78	0	0	59	0	0	0	65	63	64
Total CO ₂ captured [tCO ₂ hr ⁻¹]	0	21	99	23	23	82	0	0	0	65	63	64
Fraction carbon captured [% input C]	0%	14%	65%	0%	16%	58%	0%	0%	0%	49%	47%	48%
<i>Production summary</i>												
Bio-fuels production [MW]	182	182	182	203	203	203	175	175	175	175	98	180
Net power generation [MW]	7	4	-23	19	16	-4	-4	-12	12	-1	59	-19
Bio-fuel production efficiency (HHV)	39%	39%	39%	49%	49%	49%	44%	44%	44%	44%	25%	45%
Total energy efficiency (HHV)	41%	40%	37%	53%	53%	48%	43%	43%	47%	44%	39%	43%
Specific C emissions [tC GJ _{biofuel} ⁻¹] ^c	0.000	-0.009	-0.036	0.000	-0.009	-0.030	0.001	0.003	0.000	-0.028	-0.048	-0.022
Specific C emissions [tC GJ _{biofuel} ⁻¹] ^d	-0.002	-0.010	-0.036	-0.004	-0.012	-0.030	0.001	0.003	-0.003	-0.028	-0.075	-0.022
Bio-fuel in C-neutral blend [%vol] ^c	100%	75%	43%	100%	75%	47%	106%	119%	100%	39%	27%	45%
Bio-fuel in C-neutral blend [%energy] ^c	100%	68%	34%	100%	68%	38%	106%	119%	100%	40%	28%	45%

Table 3.4 --- Continued

Design basis												
Bio-fuel Version ^a	Ethanol Base ^b	Ethanol OG	Ethanol OG+FG	Ethanol Base	Ethanol OG	Ethanol OG+FG	FT Base-A	FT Base-B	FT Base-C	FT CCS-A	FT CCS-B	FT CCS -C
Reference	[12]	[12]	[12]	[13]	[13]	[13]	[14]	[14]	[14]	[14]	[14]	[14]
Economic												
<i>Plant costs</i>												
Total Capital Requirement [\$M]	238	254	311	197	214	257	230	217	251	289	316	333
Capex [\$ W _{biofuel} ⁻¹]	1.3	1.4	1.7	1.0	1.1	1.3	1.3	1.2	1.4	1.8	3.4	2.0
Annual O&M [\$M yr ⁻¹] ^c	18	20	29	21	24	30	15	17	9	20	(0)	28
Specific O&M [\$ GJ ⁻¹]	3.15	3.54	5.03	3.34	3.73	4.73	2.66	3.13	1.60	3.55	(0.09)	4.94
<i>Performance summary</i>												
Bio-fuel production price [\$ GJ ⁻¹]	15	16	18	13	14	16	14	14	13	16	23	18
Mitigation cost (oil @ 27\$/bbl) [\$ tC ⁻¹] ^c	409	304	203	306	234	171	370	425	317	187	240	264
Mitigation cost (oil @ 54\$/bbl) [\$ tC ⁻¹] ^c	1	28	65	(102)	(42)	15	(64)	(61)	(92)	25	127	80
Mitigation cost (oil @ 27\$/bbl) [\$ tC ⁻¹] ^d	376	293	203	251	207	171	370	425	271	187	171	264
Mitigation cost (oil @ 54\$/bbl) [\$ tC ⁻¹] ^d	1	27	65	(83)	(38)	15	(64)	(61)	(78)	25	91	80

^a "Base" refers to the adapted base model without CCS; "OG" refers to capture of fermentation off-gases; "PCC" refers to post combustion CO₂ capture from boiler flue gas; Hamelinck versions Base-A, Base-B, Base-C, CCS-A, CCS-B, and CCS-C refer to published versions 21, 22, 40, 36, 37, and 39, respectively [14]. ^b Modified to reflect an ethanol production rate of 81 gallons per short ton biomass, up from 68 in the published base case (units as published). ^c Includes carbon emissions from net electricity imports, but no credit for electricity exports, based on average carbon intensity of US electricity, as specified in Table 3.3. ^d Includes carbon emission and mitigation credit from net electricity imports and exports, based on average carbon intensity of US electricity, as specified in Table 3.3. ^e Includes credit (cost) from electricity exports (imports).

emissions with only small increases to the ethanol selling prices. Adding PCC to waste biomass combustion systems substantially increases both carbon capture and ethanol selling prices. It is plausible that integration of waste biomass gasification with PCS (rather than combustion with PCC) could achieve similar capture rates with lower costs. This alternative would likely reduce the energy penalty of carbon capture; however, the magnitude of potential savings in terms of the selling price of ethanol is not clear.

Integration of CCS within biomass FT production yields cost premiums and capture rates that are broadly similar to adding PCC to ethanol production. However, the tradeoffs of CCS integration are less straightforward in the FT cases, as the least cost configurations with CO₂ separation are substantially different from the least cost configurations without.

As in the electric sector, interpretation of these results is difficult without comparison to current fossil alternatives. To provide this context, biofuel selling prices are plotted as a function of carbon price in Figure 3.9 for all versions of the ligno-cellulosic ethanol and FT production systems with and without CCS.

Gasoline is assumed to be the fossil basis for calculating mitigation costs. Although refiner selling prices for gasoline as a function of oil acquisition cost are relatively constant, the acquisition cost of oil has been rising rapidly over the past five years. As a result, the reference case in the Annual Energy Outlook 2006 (“AEO 2006”), published by the U.S. Department of Energy, projects oil prices through 2030 to be between 43 and 54 dollars per barrel (“\$/bbl”) [56]. This is up from a maximum reference case price of 33 \$/bbl in their Annual Energy Outlook 2005 (“AEO 2005”) [57]. Although the basis

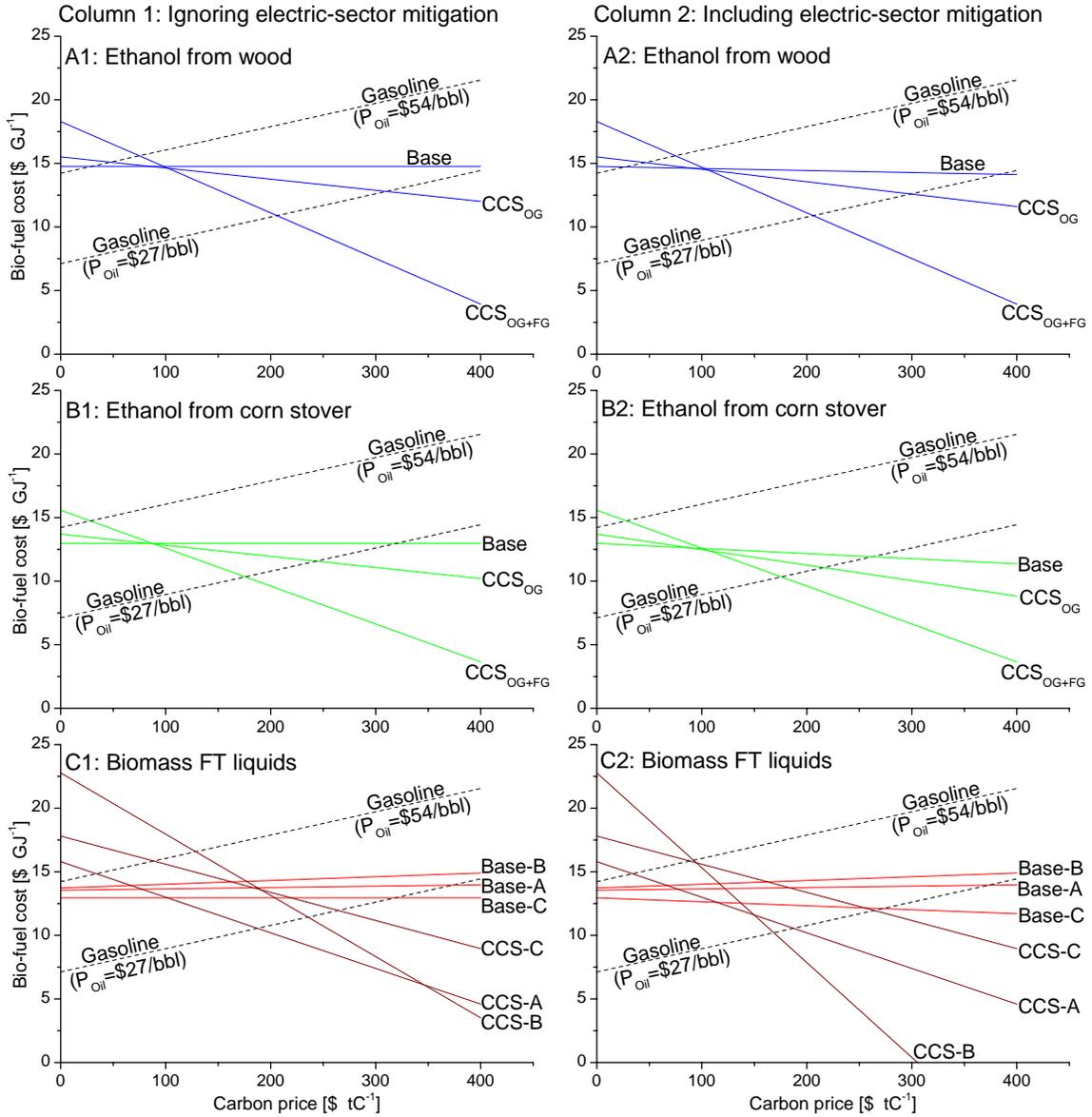


Figure 3.9. Biofuel producer costs plotted as a function of carbon price. Costs are plotted for the biofuel production systems characterized in Table 3.6 and for gasoline, assuming oil prices of 27 and 54 dollars per barrel. Electric-sector carbon mitigation from electricity exports are ignored in the plots in Column 1 and credited to the biofuel in Column 2. Emissions from electricity *imports* are counted in all plots. Producer costs for ethanol from wood, ethanol from corn stover, and FT liquids are plotted in Rows A, B, and C, respectively. Cost curve labels are consistent with technology labels in Table 3.6. In this figure, mitigation costs are defined by the carbon price at which biofuel cost curves intersect the gasoline cost curves. Notice that mitigation costs are highly sensitive to assumptions about gasoline prices. Biofuels without CCS may be cost competitive with gasoline at zero carbon price if oil prices remain high. With low oil prices, integration of CCS can substantially reduce mitigation costs of biofuels production, as indicated by the relative carbon prices at which biofuel production cost curves intersect the gasoline cost curve associated with oil prices of \$27 per barrel.

for these projections has been modified slightly, this stark upward revision underscores (but likely understates) the uncertainty in projecting future oil, and therefore gasoline, prices. Therefore, two alternate gasoline prices are used for calculating mitigation costs and to plot two associated curves for gasoline in Figure 3.9: one assuming refiner oil acquisition costs of 27 \$/bbl (the lowest projected world oil price in the AEO 2005 reference case) and one assuming oil costs of 54 \$/bbl (the AEO 2006 reference case maximum). This range is not claimed to represent any particular confidence interval on future oil prices (as both are from NEMS reference cases); however, they do provide some sense of the mitigation cost sensitivity to oil and associated gasoline prices across a plausible range.

Note that, consistent with the assumptions above, only carbon emissions from biofuel production operations and end-user combustion are considered in this analysis. Lignocellulosic biomass feedstock is assumed to be delivered to the facility on a carbon neutral basis (i.e., produced in a sustainable manner and ignoring fossil inputs to production), and other indirect life-cycle emissions are ignored. Carbon emissions from electricity imports are estimated with the average carbon emissions factor of the U.S. electric sector (calculated by dividing total GHG emissions from electricity generation by total electricity generated [54, 55]). Similarly, an emissions credit could arguably be assessed for electric sector mitigation from electricity exports; model results are calculated with and without this credit, as described in Table 3.4. Only direct emissions from gasoline combustion are considered in calculating baseline energy costs. As discussed above with respect to the emissions accounting in the BIGCC modeling, the net effect on results of

employing a life-cycle analytic framework for emissions accounting is not clear. Such accounting is beyond the scope of this analysis.

As illustrated in Figure 3.9, biofuels without CCS may become competitive with gasoline with future oil prices near the top of the range illustrated. In this scenario, ethanol with CCS from fermentation off-gases dominates baseline ethanol with carbon prices between ~50 and ~100 \$/tC and ethanol with maximum CCS dominates with carbon prices greater than ~100 \$/tC. Similarly, with high oil prices, biomass FT-CCS dominates baseline biomass FT with carbon prices greater than ~80 \$/tC. The figure suggests that the economics of ethanol (based on the results of Aden et al.[13]) and FT may be quite similar for baseline systems and those with maximum CCS. Note that the performance of these systems is nearly identical if the 15% price discount for ethanol (from efficiency benefits relative to gasoline in internal combustion engines) is removed.

With oil prices near the bottom of the illustrated range mitigation costs for biofuel systems with CCS are substantially lower than those without. The additional costs for these systems are more than offset by their negative emissions. This is in contrast to the BIGCC-CCS modeling results, which show higher mitigation costs for CCS technologies. However, biomass-CCS technologies are the least cost options in all cases with sufficiently high carbon prices.

3.5. Competition under a carbon constraint.

Biomass-based GHG mitigation strategies will face complex competitive pressures across multiple markets. Bio-energy will face competition in providing low-carbon energy products (across multiple sectors and markets); emissions offsets will face competition in providing cost-effective mitigation in each sector and may eventually face competition from direct air capture systems [58]; and alternate biomass strategies may face competition from one another for access to limited biomass resources. Moreover, these examples focus on carbon mitigation, which is but one of the many potential drivers for competition and technological change in the energy system. To explore the implications of at least some aspects of potential competition, a simple top-down stochastic model of energy costs is developed that accounts for uncertainty in fuel prices, capital costs, and operating costs for several technologies in the transportation and electric sectors.

The stochastic model calculates energy costs as the sum of fuel costs, operating and maintenance costs, sequestration costs (for technologies with CCS), and capital costs. Capital costs are amortized over 20 years with a 10% annual interest rate. Annual operating and maintenance costs are estimated as a fraction of capital costs, 5% for conventional electric-sector technologies and 7% for biomass technologies. The percentage for biomass technologies is derived from the ratios of O&M costs to capital costs in the engineering-economic modeling results presented in Chapter 3. Parameter values and distributions used in the stochastic model are provided in Tables 3.5, 3.6, and 3.7; fuel and technology capital cost distributions are illustrated graphically in Figures

Table 3.5
Assumed economic parameters

Parameter	Value
Discount rate	10%
Utilization (electricity)	0.8
Utilization (fuels production)	0.9
Project life [yrs]	20
CO ₂ storage cost [\$/tCO ₂]	10

Table 3.6
Assumed fuel parameters

Fuel	C-intensity [kgC/GJ]	Cost [\$2005 GJ ⁻¹]		
		Min	Mode	Max
Coal	24.2	1	1.5	2.2
Natural gas	13.6	3.5	5.5	8.3
Biomass	25.1	2	3	5.5
Gasoline	18.2	7	14.59	25.963

Table 3.7
Assumed technology parameters

Technology	Efficiency (HHV)	C-capture [% Carbon]	O&M [% Capital]	Capital cost [\$2005 W ⁻¹]		
				Min	Mode	Max
Pulvarized Coal	40%	0%	5%	1.10	1.25	1.65
Pulvarized Coal - CCS	28%	90%	5%	1.75	2.00	2.65
Coal IGCC	43%	0%	5%	1.10	1.40	1.75
Coal IGCC - CCS	35%	90%	5%	1.38	1.80	2.32
Co-fire	40%	0%	5%	0.10	0.20	0.30
Co-fire - CCS	28%	90%	5%	0.10	1.10	2.10
Natural Gas CC	55%	0%	5%	0.47	0.55	0.75
Natural Gas CC - CCS	47%	90%	5%	0.85	1.00	1.40
BIGCC	34%	0%	7%	1.05	1.25	1.97
Biomass IGCC _{O2}	37%	0%	7%	1.21	1.96	3.06
Biomass IGCC-CCS _{R,SG}	24%	55%	7%	1.60	2.06	3.28
Biomass IGCC-CCS _{R,FG}	21%	62%	7%	1.80	2.34	3.74
Biomass IGCC-CCS _{NR}	28%	44%	7%	1.44	1.78	2.82
Biomass IGCC _{O2} - CCS	30%	90%	7%	1.52	2.52	4.06
Ethanol	45%	0%	7%	1.30	1.59	1.95
Ethanol-CCS _{OG}	45%	15%	7%	1.35	1.70	2.20
Ethanol-CCS _{OG,FG}	45%	60%	7%	1.60	2.07	2.57
Bio-FT	45%	0%	7%	1.30	1.59	2.00
Bio-FT-CCS	45%	50%	7%	1.75	2.17	2.75

3.10 and 3.11, respectively. The distributions are intended to reflect the potential cost and performance of technologies benefiting from at least 10 years of focused research and development, consistent with the analyses presented in Chapter 3.

As indicated by Table 3.7, a variety of technologies are characterized in the stochastic model. Fossil fuel technologies include: new pulverized coal (“PC”); coal IGCC; and natural gas combined cycle (“Natural Gas CC”). Electricity costs for each of these technologies are estimated with and without CCS. Electric-sector biomass technologies include the IGCC and IGCC-CCS systems developed in Chapter 3. In addition, purely hypothetical oxygen-blown biomass IGCC and IGCC-CCS systems are characterized and included in the stochastic model. This is because biomass could arguably be used in systems with technologies similar to those of coal IGCC; such systems are capable of substantially higher carbon capture rates than the BIGCC-CCS systems modeled in Section 3.3. As a result, bio-energy systems leveraging such technology could have substantially greater negative carbon emissions, with potentially improved economic performance, relative to the other BIGCC-CCS systems included in the stochastic model. Parameter values used for these systems in the stochastic model are derived from the coal IGCC parameter values. While results for these options are interesting, they should be interpreted with particular conservatism, as the associated model parameter values are not developed from specific bottom-up engineering-economic analyses. Liquid fuel technologies include bio-ethanol and biomass FT liquids production. Consistent with the analysis in Chapter 3, costs are estimated for bio-ethanol production with three levels of CCS integration (zero CCS, capture from fermentation off-gas, and capture from flue gas

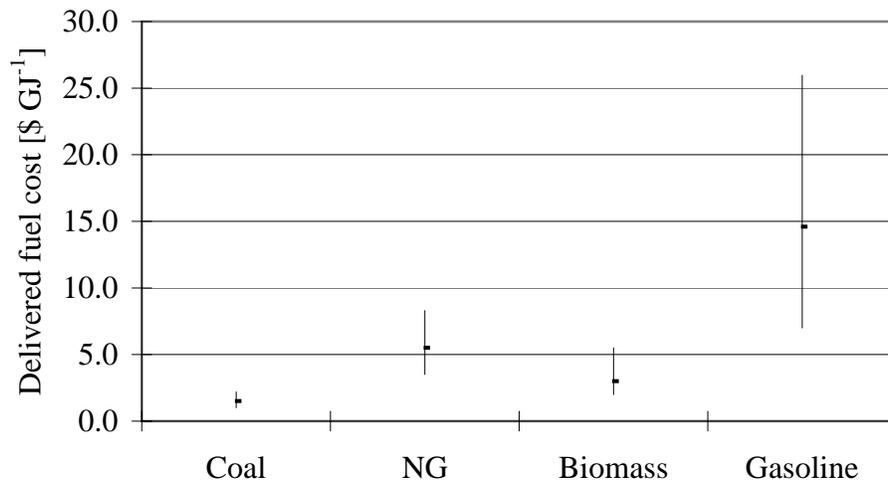


Figure 3.10. Energy cost model fuel cost distributions

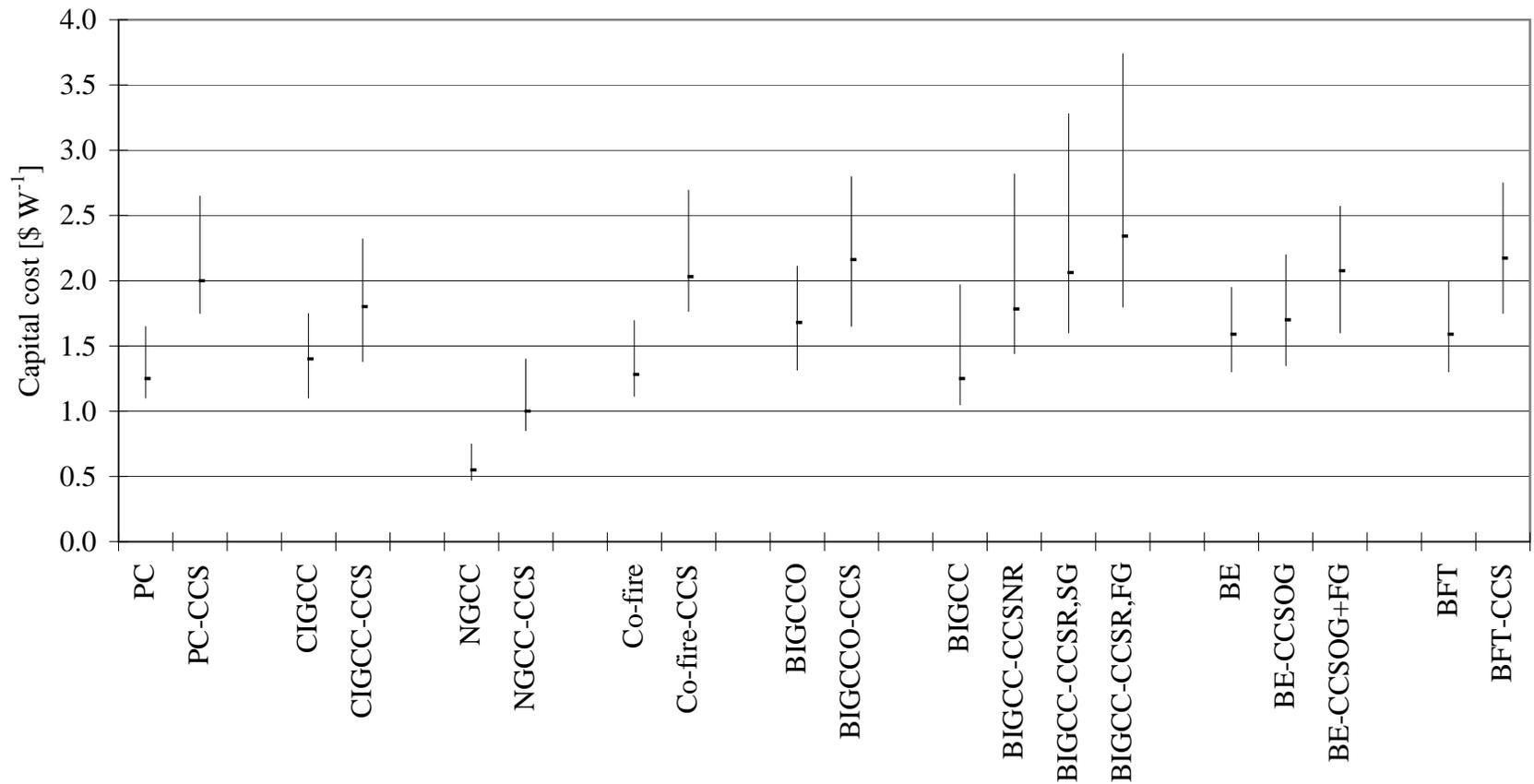


Figure 3.11. Energy cost model technology cost distributions

and fermentation off-gas). Production costs are estimated for FT liquids from biomass with and without CCS.

As described in Appendix E, technology and fuel cost distributions used in the stochastic model are developed from the analyses developed in Sections 3.3 and 3.4 in conjunction with both an expert elicitation developed specifically to support this analysis and with reference to independently published estimates in the literature. Notice that costs in the top-down stochastic model appear substantially higher than those presented in Sections 3.3 and 3.4. This is due in large part to the fact that they are presented in year 2005 dollars, which are ~21% higher than the year 2000 dollars used in the bottom-up engineering-economic analyses, as described in Appendix E.

The primary objective of the stochastic model is to evaluate the relative economic performance of potentially competing energy systems under a carbon constraint. Multiple metrics exist for comparing economic performance, but in this context, carbon mitigation cost is arguably the most relevant. As discussed previously in this chapter, mitigation cost, or the cost of emissions avoided, is defined as the difference in producer costs divided by the difference in emissions for each mitigation technology relative to a comparable baseline or reference technology. Mitigation costs, therefore, depend on the choice of reference technology.

Although mitigation costs are often calculated relative to reference technologies with core technology assumptions similar to those underlying the mitigation technology of

interest (e.g., mitigation costs for coal IGCC-CCS may be defined relative to coal IGCC, or mitigation costs for NGCC-CCS may be defined relative to NGCC), that type of pairwise comparison seems both irrelevant and overly complex in the current context. For example, the mitigation cost of biomass IGCC with CCS calculated relative to biomass IGCC is only relevant if it is *greater* than the mitigation cost calculated relative to a more widely utilized power generation technology; in other words, such a comparison matters only if biomass IGCC is a relevant baseline technology. Therefore, mitigation costs are developed here for power generation and liquid fuel production technologies relative to PC coal and gasoline, respectively. This provides a common basis for comparison that is relevant in the context of modern energy markets, even if it is somewhat inconsistent with more conventional engineering-economic analyses of CCS technologies.

While facilitating direct comparisons across technologies, mitigation costs evaluated in this way provide insufficient resolution into each technology's economic performance relative to the full suite of alternatives, particularly in the context of the inverse relation between producer cost and carbon price for biomass-CCS technologies. Therefore, a second point of comparison is calculated for biomass technologies, defined here as the market entry carbon price (MECP). The MECP is intended to describe the carbon price at which each biomass technology could enter a market for low-carbon energy products; it is defined as the carbon price at which each technology begins to dominate all relevant competitive technologies. For non-CCS biomass technologies, relevant competitive technologies include fossil technologies (with and without CCS) within the same market; for biomass-CCS technologies, relevant competitive technologies also include non-CCS

biomass technologies with similar underlying core technology. For example, the MECP for bio-ethanol with CCS is the carbon price at which it can produce ethanol at a cost lower than gasoline or bio-ethanol without CCS.

Note: this stochastic model is not intended to predict relative contributions from the technologies in future energy markets, such analysis would require a coupled model of the energy sector. However, understanding the relative economic performance of these technologies does provide some insight into their likely performance within the competitive environments discussed above.

Detailed explanation of this stochastic energy cost model is provided in Appendix E.

Figure 3.12 plots results from Monte Carlo simulation as cumulative distributions for mitigation cost in Column 1 and for MECP in Column 2, facilitating vertical comparisons across panels. The figure is further divided into three rows; results for electric-sector fossil-CCS systems, electric-sector biomass systems, and biofuels production systems plotted in Rows A, B, and C, respectively. MECP is not defined for fossil-CCS systems, enabling a figure legend to be provided in Panel A2.

Consistent with the results presented in Chapter 3, comparison of Panels A1 and B1 indicate that biomass-CCS will not tend to reduce mitigation costs in the electric sector. Biomass-based mitigation costs are generally at least as high as those for fossil-CCS technologies, and (except for oxygen-blown gasification technologies) mitigation costs

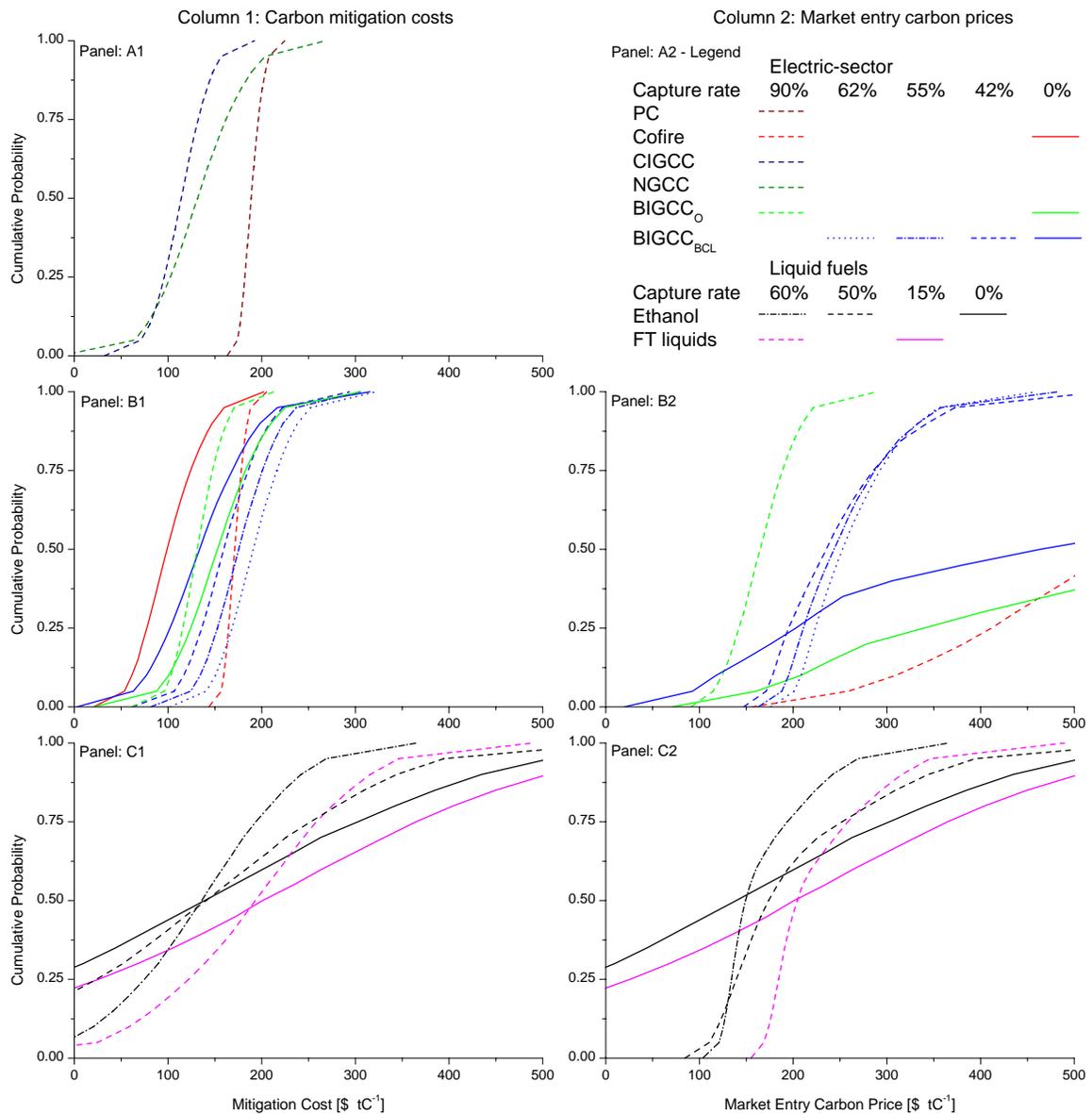


Figure 3.12 Simulation results: Cumulative distributions of mitigation costs and MECP. The figure is divided into two columns; distributions for mitigation costs and MECP are plotted in Columns 1 and 2, respectively. The figure is further divided into three rows, plotting distributions for electric-sector fossil-CCS systems, electric-sector bio-energy systems, and biofuels production systems in rows A, B, and C, respectively. A figure legend is provided in Panel A2, as MECP is not defined for fossil-CCS systems; notice that curves for systems without CCS are plotted in solid lines. Comparison across panels A1 and B1 suggests that it is unlikely that biomass-CCS can lower mitigation costs in the electric sector. Comparison across row B suggests that in the electric sector biomass-CCS is substantially less sensitive to competitive pressure from fossil-CCS options than biomass options without CCS. The plots in row C indicate that mitigation costs and MECP for biofuels vary over a wide range, with options including CCS somewhat less variable than options that don't. Biofuels-CCS options begin to dominate non-CCS options at carbon prices between \$100 to 200 per tC.

for biomass-CCS options are generally dominated—on a first order stochastic basis¹—by non-CCS options (see Panel B1). Mitigation costs associated with biofuels production are highly variable, reflecting their sensitivity to petroleum prices, as described in Section 3.4.3 and below. However, biofuels options with CCS appear to be somewhat less variable options without CCS. These results support the conclusion that, all else being equal, biomass mitigation will generally not be cost-competitive with fossil-CCS mitigation options in the electric sector, and that unless petroleum prices remain relatively high, non-CCS biomass options in the electric sector will tend to dominate both electric sector biomass-CCS and biofuel options.

Results from analysis of relative MECP is not completely consistent with those from analysis of relative mitigation costs. The curves in Panel B2 suggest that the carbon price at which electric-sector bio-energy systems without CCS could enter a competitive market for low carbon energy products is widely variable. This can be explained by the potential for fossil-CCS options to be lower cost than biomass systems without CCS until very high carbon prices, order 10^3 . In contrast, the negative slopes of energy cost curves for biomass-CCS options as a function of carbon price, as illustrated in Figure 3.8, yield relatively stable MECP, even when fossil-CCS options are relatively low cost. These results suggest that, although mitigation costs for electric sector bio-energy options without CCS may have lower mitigation costs than biomass-CCS options, biomass-CCS may be more competitive in the context of a competitive market for low carbon energy

¹ In this case, the property of first order stochastic dominance is exhibited when the entire cumulative distribution for one option is to the left of the cumulative distribution for another option with no overlap. For example, in Figure 3.12, coal IGCC-CCS exhibits first order stochastic dominance over NGCC-CCS. This does not imply that the cost associated with the first order stochastically dominant option is lower than that of the other option in every model iteration. That property is termed “absolute dominance”.

products. Moreover, MECP for electric sector biomass-CCS options suggest that these systems are capable of providing indirect mitigation of emissions sources across the economy at carbon prices that may be both relatively low and relatively predictable .

MECP for electric-sector biomass systems are generally higher than associated mitigation costs, reflecting competitive pressures from fossil-CCS options. Because analogous fossil options are not included in analysis of biofuels production systems, the implication is that biofuels appear to be relatively more competitive when considering MECP. This may suggest a more competitive environment for biomass resources, depending on petroleum prices, than is indicated by comparison of relative mitigation costs alone. It is noteworthy that alternate biomass technologies may not compete directly for feedstock due to their different sensitivities to specific fuel parameters. For example, biomass gasification technologies are generally more sensitive to the high and variable alkali levels in herbaceous feedstock types than fermentation technologies. As a result, herbaceous energy crops, such as switchgrass, which may be cheaper to produce than woody crops [59-61], may be primarily useful for bio-ethanol applications. This does not, however, alleviate potential competition for the inputs to agricultural production (e.g., land), which will likely persist and drive up the costs of feedstock and downstream energy products across all bio-energy markets.

Cumulative distributions for the lowest MECP in biomass power applications minus the lowest MECP in biomass liquid fuel applications are plotted Figure 3.13 to explore potential cross-sector competition for biomass resources. The figure is divided into two

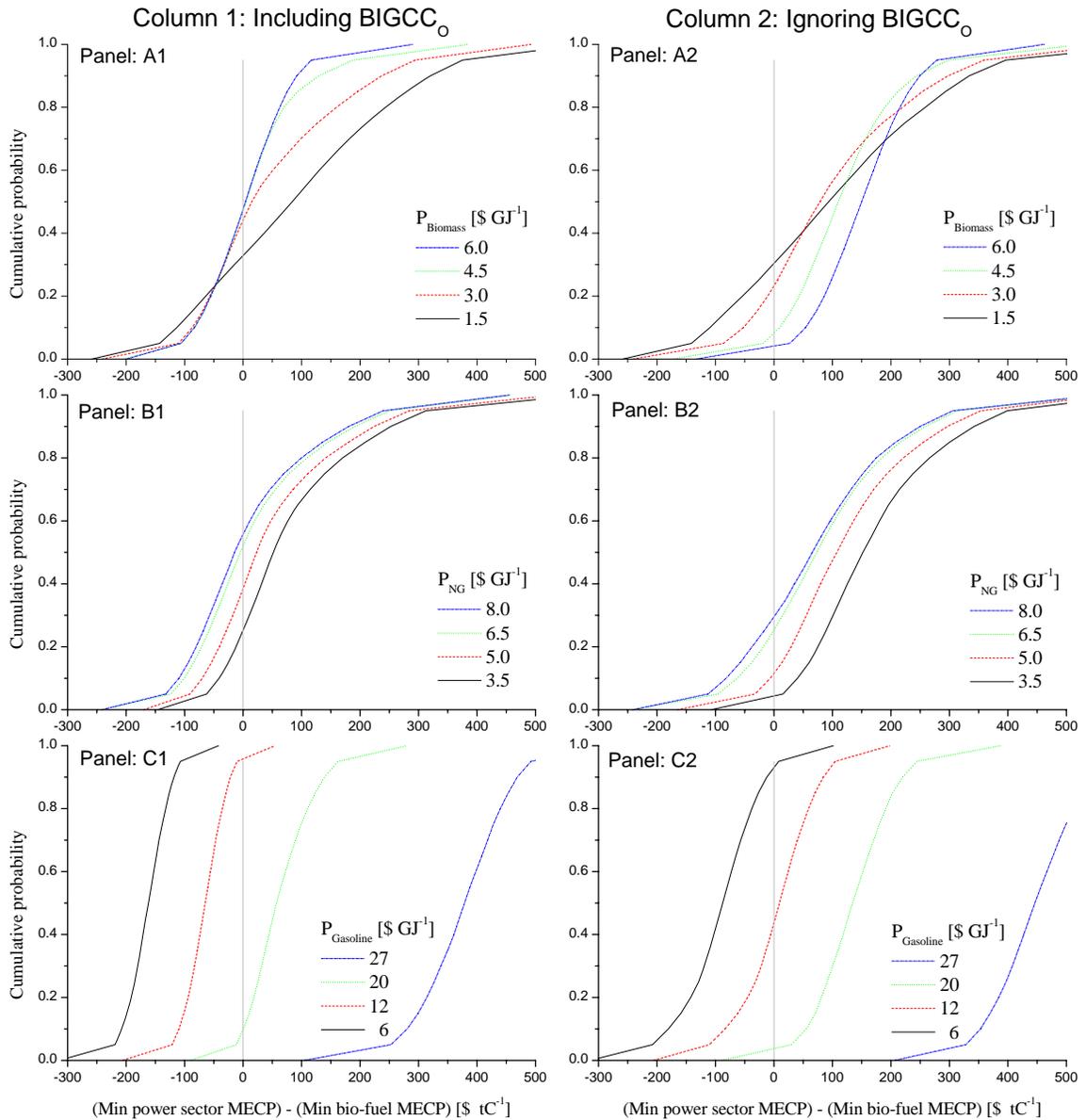


Figure 3.13. Simulation results: Sector-specific dominance and fuel price sensitivity. Cumulative probability distributions are plotted for the difference between the lowest MECP options in each sector [(minimum MECP of electric-sector biomass options) – (minimum MECP of bio-fuels options)], as a measure of absolute sector dominance. The figure is divided into two columns, with curves including and ignoring oxygen-blown biomass IGCC options plotted in Columns 1 and 2, respectively. These curves are differentiated because Oxygen-blown BIGCC options both dominate the electric sector and are studied in least detail within this thesis. The figure is further divided into three rows of panels, labeled A, B, and C, illustrating sensitivity to biomass, natural gas, and gasoline fuel prices, respectively. Consistent with results in Section 3.4, the curves in Row C indicate that the relative performance of biofuels options (and associated sector-specific dominance) is highly sensitive to petroleum prices. The sector-specific dominance of bio-energy systems is sensitive, to a lesser extent, to natural gas prices and is not (systematically) sensitive to biomass price.

columns; distributions including and ignoring oxygen-blown biomass gasification options are plotted in Columns 1 and 2 respectively. This is because, as noted above, these technologies tend to dominate other electric sector bio-energy systems, but have been examined in the least detail within this thesis. The figure is further divided into three rows; distributions are plotted as a function of biomass price, natural gas price, and gasoline price (as a proxy for oil price) in Panels A, B, and C of the figure, respectively, to understand the sensitivity of results to future fuel prices, which tend to be highly uncertain.

The results indicate that sector-specific absolute dominance² in MECP is only exhibited with very high or (if oxygen-blown BIGCC options are included) with very low gasoline prices. More generally, the relative performance of electric-sector bio-energy systems and bio-fuels production systems is sensitive to prices for competitive fossil fuels. Increasing gasoline prices are associated with increasing dominance of biofuels; increasing natural gas prices are associated with increasing dominance of power sector technologies. This is not surprising, as increasing sector-specific fossil fuel prices allow biomass options to be more competitive within that sector. The relative performance of bio-energy systems across these sectors is generally not sensitive to biomass fuel prices. Although the shape of the curve changes as a function of biomass price, it does not systematically become more positive or negative.

² In this case, absolute dominance means that the cost associated with the least cost option in one sector is lower than that associated with the least cost option in the other sector for every iteration in the simulation. It is exhibited when the cumulative distribution for the difference in least cost options for each sector lies entirely above or below zero, as in the distributions associated with very high and low gasoline prices plotted in Figure 3.13, Panel C1.

Note: the stochastic model and the discussion above assume even feedstock prices across technologies, which may not be valid, given the differences in technology sensitivity to certain biomass feedstock parameters and differences in production cost by feedstock type, as noted above. Relatively low production costs of switchgrass should tend to favor biofuel applications.

These stochastic modeling results are generally consistent with those presented in Chapter 2 and Sections 3.3 and 3.4. For example, cofire mitigation costs are found to be generally below \$100 per tC, which is consistent with results presented in Figure 2.3. Median mitigation costs (with cumulative probability of 0.5) for BIGCC systems are found to be between \$100 and \$200 per tC, which is generally consistent with results presented in Table 3.2. Finally, mitigation costs for biofuels are found to be either highly positive or negative depending on petroleum prices, which is consistent with results presented in Table 3.4.

3.6. Discussion

The general arguments presented in Section 3.1 and the specific system designs of Sections 3.3 and 3.4 demonstrate that the generation of negative atmospheric carbon emissions by integrating CCS and biomass energy technologies is both feasible and potentially important. The designs discussed here represent several possible systems; other designs are feasible and will likely have technical and economic advantages (e.g.,

oxygen-blown gasification for IGCC-CCS applications) and be easier to deploy in the near term (e.g., retrofit of existing, non-ligno-cellulosic ethanol facilities to capture fermentation off-gases).

Regardless of the specific route, the ability of biomass-CCS to generate negative atmospheric emissions could fundamentally change the role of biomass in achieving deep emissions reductions by providing a mechanism to offset emissions anywhere in the economy. Moreover, because atmospheric CO₂ is well-mixed on a global scale, emissions offsets could be effectively applied to distant emission sources. This may create unique opportunities for nations—particularly in the developing world—with large agricultural resources, as international sale of locally generated emissions offsets could subsidize domestic production of bio-energy products. These bio-energy products could be used domestically or exported, particularly if they include biofuels.

Note that offset fossil emission sources could be coupled with or independent from associated biomass-CCS systems, depending on the carbon management framework. For example, in a tightly coupled system, coal-fired power plants could be made carbon-neutral by cofiring 10% biomass on a carbon input basis and employing 90% carbon capture. In a loosely coupled system, a blend of fossil and biofuels could be made carbon neutral by integrating CCS in biofuel production and crediting negative emissions to the fossil components of the fuel blend. Finally, in a decoupled system, negative emissions from dedicated biomass-CCS, such as BIGCC-CCS, could offset emissions sources anywhere in the (global) economy.

The results for BIGCC technologies do not suggest that integration of CCS will reduce electric sector mitigation costs, though it is plausible that such reductions would be possible with other subsystem technologies (e.g., oxygen-blown biomass gasification, or cofired IGCC with CCS). However, integration of CCS does not dramatically increase mitigation costs either, indicating that BIGCC-CCS technologies should be generally considered with BIGCC in scenarios calling for deep reductions in CO₂ emissions. However, the economics of BIGCC-CCS are likely to be increasingly compelling as emissions targets force mitigation beyond the large-scale, centralized sources of the electric sector, increasing the demand for emissions offsets.

The results for biofuel technologies are starkly different. First, the competitiveness of biofuels is strongly dependent on future oil prices as well as on the economic value assigned to energy security benefits of biofuels (which are generally not relevant for biomass power applications). With high values for these parameters, biofuels may be cost competitive with fossil transportation fuels, even absent carbon constraints. In this context, CCS from fermentation off-gases and gasification or combustion processes become important at carbon prices between 50 and 100 \$/tC.

In contrast, CCS integration substantially reduces mitigation costs for liquid fuels under scenarios with low oil prices and no economic value assigned to energy security benefits. The reason for this can be appreciated by considering the curves in Figure 3.9. The slopes of the curves for gasoline and biofuels without CCS are sufficiently similar that

the negative slopes of the curves for biofuels with CCS can yield mitigation cost reductions even with large energy cost differences at zero carbon price. These characteristics of the cost curves in Figure 3.9 are relatively fundamental, suggesting that this conclusion is fairly robust.

In addition, integrating CCS with biofuel production fundamentally changes mitigation options for the transportation sector. One of the key challenges for carbon mitigation with biofuels has been that complete mitigation implies complete substitution for fossil fuels. This creates fundamental challenges due to the requisite scale of biofuel production (particularly with respect to agricultural input requirements) and to certain fuel characteristics of biofuels (particularly ethanol) which can compromise their utilization for internal combustion applications on an unblended, or “neat”, basis [62]. However, maximizing CCS integration with biofuels production and allocating the resulting offsets to associated fossil transportation fuel emissions could yield carbon-neutral blends with less than 50% biofuel by volume (less than 40% by energy), as indicated in Table 3.4.

However, given the limited options for mitigating transportation sector carbon emissions in the near to medium term, and given uncertainty in oil prices and therefore in the mitigation costs of biofuels, it is worthwhile to consider the transportation sector mitigation potential of all biomass-CCS applications. Emissions offsets from biomass-CCS could be applied to transportation sector emissions, regardless of primary energy products. In this context, transportation sector emissions can be mitigated by negative

emissions and fuel substitution from biofuel applications or by negative emissions from electric sector biomass-CCS applications.

Table 3.8 compares the transportation sector mitigation potential of one ton biomass in several biomass-CCS technologies. Note that the transportation sector mitigation potential of biomass electricity with 90% carbon capture is included in addition to the technologies discussed above, as costs are not considered, and this option is clearly feasible (with uncertain costs) using oxygen-blown BIGCC with PCS, biomass combustion with PCC or oxyfuel, or biomass cofire with CCS. Note that the mitigation potential of the hypothetical electric sector technology with 90% carbon capture is generally at least as great as for biofuel applications. This suggests that if future oil prices are low, it is plausible that electric-sector biomass-CCS technologies could provide the most economically efficient means for mitigating transportation sector emissions. In this scenario, electric-sector biomass-CCS represents a hedge against the possibility of low oil prices driving up the cost of direct mitigation in the transportation sector. The evolution of such a scenario is not speculated here, as predictions of future oil prices are notoriously unreliable; however, the example demonstrates the flexibility inherent to indirect mitigation with biomass-CCS offsets. This flexibility provides important advantages within a portfolio approach to achieving deep emissions reductions and only increases the opportunities for biomass-based mitigation.

Much work remains in resolving the technical and economic performance of biomass-CCS technologies. The systems evaluated in this analysis represent only a small subset

Table 3.8
Transportation sector mitigation potential of biomass-CCS technologies

Modeling basis								
Primary energy product	Power	Ethanol	Ethanol	Ethanol	Ethanol	FT	FT	FT
Version ^a		OG	OG+FG	OG	OG+FG	CCS-A	CCS-B	CCS-C
Reference	N/A	[12]	[12]	[13]	[13]	[14]	[14]	[14]
<i>Transportation sector mitigation</i>								
<i>Gasification & CHP CCS</i>								
Carbon Available (tC/tbio.)	0.50	0.29	0.29	0.21	0.21	0.27	0.26	0.27
Carbon Capture Rate (%)	90%	0	90%	0%	90%	90%	90%	90%
Mitigation Potential (tC/tbio.)	0.45	0.00	0.26	0.00	0.19	0.25	0.24	0.24
<i>Fermentation Offgas CCS</i>								
Carbon Available (tC/tbio.)	N/A	0.07	0.07	0.08	0.08	N/A	N/A	N/A
Carbon Capture Rate (%)	N/A	100%	100%	100%	100%	N/A	N/A	N/A
Mitigation Potential (tC/tbio.)	N/A	0.07	0.07	0.08	0.08	N/A	N/A	N/A
<i>Electricity imports</i>								
Correction for electricity imports [tC/tbio] ^b	N/A	N/A	-0.04	N/A	-0.01	N/A	N/A	-0.04
<i>Fuel Substitution</i>								
Bio-fuel Production (GJ/tbio.)	N/A	7.8	7.8	8.8	8.8	8.7	4.9	9.0
Mitigation potential (tC/tbio.)	N/A	0.14	0.14	0.16	0.16	0.16	0.09	0.16
<i>Total</i>								
Transportation sector mitigation (tC/tbio.)	0.45	0.21	0.43	0.24	0.42	0.41	0.33	0.37

^a 'OG' refers to CCS from fermentation offgas; 'OG+FG' refers to CCS from fermentation off gas and CHP flue gas; 'CCS-A', 'CCS-B', and 'CCS-C' refer to the three FT-CCS models characterized in Table 3.4. ^b correction to account for fossil carbon emissions from electricity imports; no credit is given for mitigation from electricity exports, as the focus of this computation is transportation-sector mitigation.

of the possible technological routes, as characterized in Figure 3.1. Moreover, the engineering-economic models developed are generally simplistic and have not been optimized. Specific future engineering-economic modeling work should include: (i) examining the potential to cofire biomass with coal in IGCC plants with CCS; (ii) developing oxygen-blown gasification technologies and characterizing their technical and economic performance with and without CCS integration; (iii) evaluating potential integration of waste biomass gasification with pre-combustion carbon separation in bio-ethanol production systems; (iv) optimizing FT production systems for CCS integration by valuing captured CO₂ in the optimization protocol; and (v) expanding the set of technological routes to biomass-CCS for evaluation in technical and economic dimensions to include methanol production and cofire with CCS, among others.

Beyond analysis of specific technologies, substantial analysis is needed to resolve the potential contributions of attractive biomass-CCS technologies, given uncertain future energy markets and biomass supply limitations and externalities. Specifically clearer understanding is needed with respect to: the domestic biomass supply curves and the various trade-offs inherent to it (e.g., impacts on the environment, food production and prices, and suburban and rural development); the international supply curve and trading potential for biomass feedstock, bio-energy products, and emissions offsets from biomass-CCS and the various trade-offs inherent to these options. As our understanding in these dimensions evolves, we will be increasingly prepared to answer critical questions regarding the roles that bio-energy and biomass-CCS should play within GHG mitigation strategies.

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Chapter 3

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Chapter 4

Policy dimensions of bio-energy and biomass-based carbon mitigation

Industrial bio-energy systems can support a variety of policy objectives, as discussed in Chapters 1, 2, and 3. However, several important challenges to development have limited adoption to date and represent substantial risk for future deployment. As a result, policy support will generally be required to achieve bio-energy's potential benefits, particularly in the United States and other nations with developed economies. A variety of policy instruments aiming to provide this support has been implemented in the U.S. and many more have been proposed; however, they are not fully coherent or well coordinated around specified policy objectives. As such, current policies may need to be revised and new instruments developed to realize bio-energy's potential benefits.

This Chapter discusses a broad set of policy relevant issues related to bio-energy systems. Specifically, Sections 4.1 and 4.2 provide characterizations of the potential benefits from and challenges to deployment of bio-energy systems, respectively; policy frameworks capable of supporting bio-energy and specific policy instruments that have been enacted or proposed in the U.S. are characterized in Section 4.3; and Section 4.4 provides a discussion of the implications of the analyses developed throughout the chapter. Many of the topics covered in this chapter are generally applicable; however, the discussion specifically reflects an American perspective and several topics—including, for example, characterizations of specific U.S. policy instruments in Section 4.3—are wholly U.S. centric. Relevant scales of applicability are noted explicitly or contextually implied

throughout the chapter.

4.1. Values, policy objectives, and potential benefits (and costs) of biomass energy

Biomass energy technologies have been variously proposed as a means to abate CO₂ emissions, improve air quality, increase energy security, enhance rural development and agricultural economics, and more generally to advance sustainability through increased use of renewable energy resources. This thesis tends to focus on climate benefits from CO₂ emissions reductions, judged here to be the dominant value of bio-energy systems (as discussed throughout this chapter and summarized in Section 4.4); however, consideration of multiple potential benefits is relevant, particularly in the context of current and potential future policies supporting bio-energy. Importantly, not all policies, even those targeting similar policy objectives, will be mutually reinforcing. For example, policies intended to encourage negative climate forcing (i.e., climate cooling) that account for albedo effects in the climate system may discourage reforestation for bio-energy supply in regions with significant seasonal snow cover [1]. The range of policy objectives that may be advanced with bio-energy systems and the potential for complex policy interactions suggests a relatively broad perspective is justified in considering policy dimensions of bio-energy and biomass-based carbon mitigation.

4.1.1. Carbon mitigation and climate benefits

From a climate perspective, biomass energy systems offer the potential to (i) provide incremental mitigation at reasonable cost in the near term, (ii) support cost-effective transition to a carbon neutral economy in the medium to long term, and (iii) enable active management of atmospheric CO₂ concentrations in the very-long term. In these ways, biomass-based strategies may provide important contributions within a portfolio approach to carbon mitigation. To the extent synergies exist for development and deployment, joint consideration of these potential roles for biomass-based mitigation across varying timescales may affect proximate bio-energy development pathways and increase the attractiveness of biomass overall. For example, such consideration may encourage development of technologies that can be leveraged across a broader set of mitigation strategies (e.g., oxygen-blown gasification), or allow investments in supply chain development to be amortized over substantially longer periods, effectively reducing delivered fuel costs and proximate mitigation costs.

Each of these potential roles for biomass-based mitigation is discussed below. In addition, a brief discussion is provided covering several plausible policy responses to the emerging capability of generating negative atmospheric CO₂ emissions. This concept, which enables offsetting emissions across the economy and active management of atmospheric CO₂ concentrations over the very long term, has precipitated several unique policy proposals [2].

Biomass-coal cofire and CO₂ capture from ethanol fermentation off-gas streams in existing facilities are characterized in Chapters 2 and 3, respectively, as means to achieve emissions reductions, in the very near term, for reasonable cost (~50 \$/tC, or ~14 \$/tCO₂). Importantly, these costs suggest that bio-energy systems can represent economically efficient means to achieving climate benefits in the near term. While the scale of these proximate reductions is generally small, even small reductions in the near term could strongly impact our ability to meet emissions trajectories for achieving long-term stabilization of atmospheric CO₂ concentrations at desirable levels [3, 4]. Moreover, there are several scenarios in which these early mitigation systems could plausibly evolve to provide more substantial contributions over medium or longer-term time horizons (see Chapters 2 and 3).

Advanced biomass technologies, including Biomass-CCS, are characterized in Chapter 3 as means to support de-carbonization of the economy over the medium and long term. Bio-energy systems may provide cost-effective low-carbon energy products, and the ability to offset emissions sources across the economy (through generation of negative emissions with biomass-CCS) adds potentially important flexibility to a portfolio of CO₂ mitigation strategies. GHG emissions offsets may be useful primarily during a period of transition, extending the time frame for deployment of carbon-neutral *direct* mitigation technologies while maintaining desired emissions trajectories, or may be part of a more permanent solution—to the extent any exist within the evolving global economy. Either way, biomass-CCS should only lower total mitigation costs (and climate damages) by providing a mechanism to offset emissions from sources where direct abatement is

expected to be technically difficult, incomplete, or expensive.

In the very long term, it is plausible that the global economy may be made carbon neutral through transition to a portfolio of yet undetermined technologies. In such a scenario, it is possible that biomass-CCS could remain important as a means for active management of atmospheric CO₂ concentrations even if biomass becomes otherwise irrelevant as a carbon-neutral primary energy resource. Such active management could enable atmospheric stabilization at pre-industrial (or other desirable) concentrations. While it is unlikely that biomass-CCS will be the only means for generating emissions offsets or actively managing atmospheric concentrations in the very long term, as direct air capture may be feasible within relevant time scales [5], the relative certainty in our ability to generate negative emissions with biomass-CCS enables integration of such management capabilities into projections and policy decisions today.

This emerging capacity to actively manage atmospheric GHG concentrations may have important implications for proximate policy making. A broad spectrum of policy options exist for integrating this capability into climate policy. This spectrum may, for example, include:

- (i) Indefinitely ignoring the potential benefits of this strategy;
- (ii) Ignoring the potential benefits of this strategy until a specific benchmark has been achieved, such as until atmospheric GHG concentrations have been stabilized, or until the risks inherent to biomass-CCS are better understood, or

- until the climate system and associated damage functions are better resolved;
- (iii) Integrating biomass-CCS and negative atmospheric emissions into modern policy frameworks and encouraging deployment when and where it is cost effective;
 - (iv) Expanding support for bio-energy systems without CCS, under the assumption that future CCS retrofits could be implemented if climate damages (or projected damages), including those from potentially abrupt climate change, motivate substantially accelerated mitigation or atmospheric CO₂ concentration reductions [2, 6];
 - (v) Targeting emissions trajectories that specifically overshoot desired atmospheric stabilization concentrations under the assumption that concentrations may be reduced to some “optimal” level over the longer term;
or
 - (vi) Postponing any level of mitigation until the magnitude and geographical distribution of the climate response to increasing GHG concentrations and the associated economic implications are known with greater certainty, relying on atmospheric GHG management to reverse unacceptable climate changes over the very long term.

Policy options (i), (ii), and (iii) described above reflect alternate perceptions of the relative risks and benefits of biomass-CCS. The first option reflects an extreme application of the precautionary principle or a perception that the risks from biomass-CCS are great relative, to its net benefits. The third option reflects a general acceptance

of this strategy or the perception that the net benefits are large relative to the risks. The second reflects an intermediate perspective of the risks and potential benefits or a perception of potentially large risks from excess scale or over reliance on negative emissions or biomass-CCS. Each of these may be justified within alternate policy environments; however, if bio-energy systems and CCS application within fossil energy systems are both acceptable, then the third option appears most rational as joint deployment of bio-energy with CCS does not appear to compound risks.

In contrast, policy options (iv), (v), and (vi) above reflect alternate perceptions of the risks and reversibility of climate damages. In this context, a critical consideration is the time frame required to reduce atmospheric concentrations to a yet undetermined “optimal” level. Likely concentrations at which atmospheric CO₂ could be stabilized before subsequent reductions could be developed (i.e., the maximum concentration attained) combined with the scale of negative emissions feasible with biomass-CCS suggests that returning atmospheric concentrations to pre-industrial levels, for example, will take a minimum of several decades and (very) likely much longer.

To appreciate this, consider a stabilized future atmospheric concentration of 500 parts per million (ppm) CO₂. Recognizing the potential for hysteresis, inertia, and (potentially asymmetric) thresholds in the climate response to changing GHG concentrations, a plausible stabilization target for active management might be 300 ppm. Equating 1 ppm atmospheric CO₂ to 2.1 GtC⁽¹⁾, assuming (i) that the global economy is otherwise

¹ Estimated by multiplying an average dry mass of the atmosphere of 5.1×10^{15} tons by an average dry mass fraction atmospheric CO₂ of 0.058%, converting from GtCO₂ to GtC, and dividing by 380 ppmv

carbon-neutral, and (ii) that bio-energy systems have a (optimistic) global average carbon capture rate of 90%, and incorporating a (very wide) range of estimates from the literature for global bio-energy feedstock production capacity equivalent to between 1 and 35 GtC/yr⁽²⁾ suggests that it would take between ~13 and ~460 years to achieve the required reduction, with bio-energy operating at maximum global capacity. Note that this calculation ignores the large and uncertain time requirements to make the global economy carbon neutral and to globally maximize biomass-CCS deployment.

During the time required for atmospheric stabilization and de-carbonization, considerable economic damage will likely have been done, at which point returning concentrations to pre-industrial or other desirable levels may not be the preferred adaptive response. This may be true even if it becomes clear, *a posteriori*, that stabilization at lower atmospheric concentrations via more aggressive mitigation would have been preferred. Specifically, it is possible that social preference ordering over outcomes may be characterized (with perfect foresight or in hindsight) as $A > B > C$, where “A” represents atmospheric stabilization at a maximum concentration of α , “B” represents atmospheric stabilization at a maximum concentration of β , “C” represents atmospheric stabilization at a maximum concentration of β with subsequent reduction to α , and $\alpha < \beta$. Such issues will likely be magnified if the climate response to increasing atmospheric GHG concentrations is

atmospheric CO₂ [7. Earth's Atmosphere. [web page] 2007 March 18,2007 [cited 2007 March 18]; Summary characterization of the earth's atmosphere]. Available from: http://en.wikipedia.org/wiki/Earth%27s_atmosphere. .

² Literature estimates for between 33 and 1130 EJ biomass per year are divided by an assumed average heating value of 16 GJ/t and multiplied by an assumed average carbon content of 50%_{mass} yield between 1 and 35 GtC/yr potential from biomass [8. Hoogwijk M., Faaij A., van den Broek R., Berndes G., Gielen D., and Turkenburg W. Exploration of the ranges of the global potential fo biomass for energy. Biomass and Bioenergy. Elsevier, London. 2003. 25(2): p. 119-133..

characterized by hysteresis, inertia, (potentially asymmetric) thresholds, or irreversible climate damages (e.g., extinctions).

As a hypothetical example, consider the potential for relatively small magnitude warming to mobilize the West Antarctic Ice Sheet (WAIS) causing rapid sea level rise sufficient to submerge coastal settlements and low-lying islands [4]. Regarding the potential policy response (iv) above, it seems (highly) unlikely that precursors to this abrupt climate change mechanism would be sensed, interpreted, and accepted by world leaders with sufficient time to mobilize resources, mitigate 100% of global GHG emissions, deploy biomass-CCS (including retrofits and new deployments), and reduce atmospheric CO₂ concentrations to a level that could prevent WAIS mobilization. As such, while this proposed policy response is intuitively appealing, the relative timescales for abrupt climate change mechanisms, atmospheric CO₂ reductions via biomass-CCS, and for achieving scientific and political consensus suggest that increasing bio-energy deployments with CCS retrofit capability does not represent a substantial precaution against the potential for abrupt climate change. However, a similar policy response may be justified to the extent it represents a cost-effective option (in the sense of a financial instrument) for accelerated future mitigation to limit incremental climate change (i.e., to support accelerating de-carbonization over time implied by emissions trajectories for achieving long term stabilization of atmospheric CO₂ concentrations at desirable levels [2, 4]).

The appeal of the potential policy responses (v) and (vi) above, where (vi) represents an

extreme version of (v), stems from the considerable cost savings that may be possible by postponing mitigation. Potential sources of such savings include the time value of money (assuming future costs are discounted), and more fundamental advantages from technological learning. However, these potential savings are not clearly justified by the ability to actively manage atmospheric GHG concentrations over the very long term via biomass-CCS. The net value of such a strategy is not clearly positive, recognizing uncertainties in technological costs and climate damage functions, and hinges on how future costs are discounted. Appropriate application of discounting methodologies for costs arising from climate change remains an area of active debate due, among other things, to the intergenerational nature of potential costs. In the example above, if the WAIS were mobilized and sea levels rose, reducing sea levels by rebuilding the ice sheet through cooling induced by active management of atmospheric GHG concentrations (equivalent to outcome “C” above) or any other means would take a *very* long time – much longer than was required to cause the damage. Adaptation by permanent resettling of displaced populations in higher elevation areas (equivalent to outcome “B”) would likely be preferred to reclaiming the submerged land. This is likely true even if it became clear, *a posteriori*, that permanent resettling implied significant net costs relative to a mitigation strategy that could have avoided the sea level rise in the first place (equivalent to outcome “A”), making $A > B > C$ as described above. The potential for irreversible climate damages and other arguments supporting aggressive application of the precautionary principle further degrade arguments to delay mitigation based on the ability to return atmospheric concentrations to pre-industrial levels.

Beyond the specific policy options discussed above, a broad range of options exists for integrating the emerging capability of generating negative atmospheric GHG emissions into climate policy. Evaluation of these options will require complex trade-offs across diverse policy attributes and technical issues. Ultimately, the available options will have to be considered in the context of expected climate damages, expected mitigation costs, the likely evolution of these costs with time and technological learning, the range of emissions trajectories achievable with and without systems for generating negative GHG emissions, the risks inherent to such an approach to GHG mitigation, the discounting methods applied to future costs and benefits, and the social risk preferences used to evaluate these various costs, benefits, and risks. More generally, the general arguments presented in Chapter 1, the economic analyses presented in Chapters 2 and 3, and the diversity of potential roles discussed in this section suggest that bio-energy systems may be capable of important contributions within a portfolio approach to GHG mitigation.

4.1.2. Rural development and agricultural economics

Rural development and agricultural economic policy have complex interactions with and implications for broader economic and policy issues across scales ranging from local to global. As such, a comprehensive understanding of the effects of existing and potential future policies supporting bio-energy systems on rural development and agricultural economics demands analysis substantially deeper than is presented here. This does not, however, preclude a high level characterization sufficient to facilitate meaningful

discussion of at least some of the potentially important dimensions of such policies, in terms of rural and agricultural economic development policy objectives. With this goal in mind, a (very) high level characterization of the national (U.S.) and international agricultural economic and policy environment is provided below. Following this are brief discussions of some potential implications of policies supporting bio-energy for agricultural economics and rural development from domestic U.S. and international perspectives.

Agricultural activities are currently subsidized in various ways in the United States and across much of the world [9, 10]. US government payments to the farm sector totaled \$24.1 billion in 2005, equivalent to 33% of net farm income and 9% of the total value of farm sector output [11]. Subsidies may support domestic production, as in minimum price guarantees for specific products, limit international competition, as in import tariffs, or affect supply and demand more indirectly, as in the conservation reserve program, which pays farmers not to produce on environmentally sensitive lands [9, 10, 12]. In the U.S., agricultural subsidy programs, in their many forms, are justified based on their support for specific policy objectives including food security, rural economic development, and environmental protection. The efficacy of such programs for achieving these objectives is not evaluated here; however, it is clear that with their various potential benefits, they do incur significant costs[9, 10]. Domestic costs manifest as direct spending of public funds and the arguably inefficient use of agricultural resources resulting from distortionary incentives and price effects.

In addition to these domestic costs, subsidy programs (primarily in developed countries) have profound effects on an international level by depressing global prices for agricultural commodities, an effect that is magnified by the use of export subsidies to promote surplus domestic production onto international markets [10]. This in turn creates global economic challenges as depressed global prices reduce the profitability of (unsubsidized) production and limit associated economic growth [9, 10]. These challenges have particularly strong implications for countries with developing economies and large agricultural resources. Trade barriers (e.g., tariffs) have been argued to create even greater distortionary market inefficiencies and are often coupled to domestic subsidy programs [10]. Recognizing these distortionary price effects and associated market inefficiencies, subsidy programs and tariffs are discouraged by the World Trade Organization, creating tension between many of its member states [9, 10].

It is within this context that policies supporting bio-energy development could make important contributions to rural and agricultural economic development both within the U.S. and on a global scale. Considering these potential contributions first from a domestic American perspective, production of bio-energy feedstock, including a potentially wide range of feedstock types and production intensities, could diversify production away from conventional agricultural commodities. This diversification could reduce production of currently subsidized conventional crops, which could, in turn, increase prices for associated commodities and decrease the scope of subsidy programs by concurrently reducing the value of subsidies required for profitability and the quantity of subsidized production [13]. The magnitude of these benefits depend on the scale of

bio-energy deployment; however, the total opportunity for bio-energy, in terms of climate or energy security objectives, suggest that agricultural diversification towards energy feedstock could support rural agricultural economic development comparable to the current suite of subsidy programs at potentially lower cost. More generally, domestic economic benefits could develop from decreasing subsidy program costs, increasing agricultural profitability, and increasingly efficient utilization of agricultural resources.

It is noteworthy that this argument hinges on the assumption that energy crop production will be profitable. U.S. experience with corn-based ethanol production for use as a fuel additive has not been positive in this regard and remains heavily subsidized. Biofuel blenders currently receive a credit of 51 cents per gallon of ethanol and additionally benefit from a 54 cent per gallon tariff on ethanol imports above 7% of U.S. demand [13]. This is in addition to government payments to the corn producers, who receive 22% of government funds paid to farm businesses [14]. More generally, absent credit for environmental or energy security benefits, bio-energy systems (except potentially biofuels under scenarios with persistently high oil prices) are generally not cost competitive in the American context with feedstock prices near levels required for agricultural profitability, as indicated by the results in Chapters 2 and 3. Therefore, bio-energy feedstock production will likely require its own set of subsidies, at least in the near term.

This potentially confounding dimension is noteworthy and warrants further analysis but should not obscure the fundamental benefits of shifting agricultural production toward

bio-energy feedstock. This holds because bio-energy subsidies should not detract from, and would likely amplify, the positive price effects of feedstock production on conventional agricultural commodities. The resulting “subsidy substitution” may limit public savings and could even increase the value of public support for agricultural production. However, spending would be spread across multiple markets (i.e., energy and food markets), potentially reducing distortionary effects within each market. Further, to the extent financial incentives are structured to support more general energy-sector objectives—for example as carbon constraints rather than direct production subsidies—it is plausible that these incentives could enable more efficient government spending than the current set of agricultural subsidy programs. However, this efficiency will tend to reduce (direct) benefits to domestic rural and agricultural economic development as some fraction of demand for low-carbon energy products will likely be met by competing energy systems, reducing the scale of bio-energy development and associated agricultural development.

A closely related concern is that diversification of agricultural production into energy markets could be successful enough to interfere with food production and threaten food security. Several studies have suggested that U.S. biomass feedstock production could be over 10^9 dry tons per year without inducing substantial food price effects, though the sensitivity of food prices beyond that level of production is generally not well understood [15-17]. While increasingly efficient markets for diversified agricultural commodities could (arguably) balance competing uses for the limited resources, it is plausible that the effect on food prices could eventually be significant and disproportionately affect the

poor. However, climate change will likely also disproportionately affect the poor due to their exposure and limited adaptive capacity [18]. The relative magnitudes of potentially adverse effects from increased food prices due to bio-energy development and from climate change are not clear, nor are the distributions of these effects across U.S. and global populations. However, substituting policies that value economic externalities, including GHG emissions, for more conventional agricultural subsidy programs could (arguably) allow these competing interests to be more effectively balanced and help support evolution of more rational agricultural commodity markets.

Observed and projected price effects attributed to ethanol production from corn are relevant in the context of this discussion [13, 19]. In particular, according to the U.S. Department of Agriculture's baseline scenario, corn ethanol production is projected to increase from ~19 GL in 2005 to ~34 GL in 2009 and ~45 GL in 2016 [13, 19].

According to the projection, this expansion, already underway, has strong implications for resource allocations, commodity supply, prices, domestic demand, and exports across the agricultural sector.

While these various effects are noteworthy, they are not clearly representative of what should be expected from expanding ligno-cellulosic (rather than corn-based) bio-energy development. This is because the effects noted above appear to be concentrated in markets for corn and closely coupled agricultural products, such as soybeans (which compete directly with corn for available acreage) and downstream feed and livestock products [13, 19]. For example, the projection indicates that the proportion of planted

cropland supporting ethanol production will increase from ~5% to ~11%; however, despite this significant diversion of agricultural resources, the resulting consumer price index (“CPI”) for food (a reasonable proxy for net price effects in the agricultural sector) is generally lower than the aggregate CPI across the projection period. The implication is that if resources diverted for energy crop production were distributed across many commodity markets (rather than concentrated in the corn market), the net price effects should be nominal. This interpretation is consistent with results from independent analysis of the impacts of ligno-cellulosic energy crop production on U.S. Agriculture, which suggest relatively small price effects for conventional agricultural commodities [15].

Analogues to these issues exist at the international level, as well. In general, programs shifting agricultural production toward bio-energy feedstock, particularly in nations with developed economies, should tend to increase global prices for conventional agricultural commodities. This could, in turn, support more profitable agricultural production and accelerate global economic development more generally, depending on the scale of bio-energy development.

One could argue that subsidized bio-energy feedstock production in the developed world could depress feedstock prices in the global market, thereby compromising the profitability of energy crop production globally. However, this is only true to the extent that trade in bio-energy feedstock would develop in response to increasing demand, and as discussed in Section 4.2.2 below, biomass feedstock transport is limited by

fundamental biomass properties, suggesting that trade in more valuable finished bio-energy products (e.g., biofuels) will tend to dominate. Independent analysis of global bio-energy supply chains tends to support this view [20]. Accordingly, it is plausible that subsidized domestic production will have negative price effects on finished bio-energy products in global markets. This may play out; however, in a world with increasing economic integration and increasing energy demand, world bio-energy prices may tend to be anchored, somewhat, by conventional energy commodity prices. Moreover, to the extent nations increasingly commit to meaningful carbon constraints, demand for low-carbon energy products may be substantially greater than can be supplied through domestic production systems. At the very least, it appears unlikely that subsidized domestic production would exceed domestic demand in quantities sufficient to depress world prices from current levels. The apparent profitability of Brazilian ethanol production at current world prices suggests that policy-induced demand increases in biofuels utilization may advance economic development in international agricultural sectors even with subsidized domestic production in countries with developed economies. Moreover, international opportunities could increase dramatically if current trade restrictions were reigned in; although such a policy shift would likely conflict with domestic agricultural development objectives.

In summary, policy scenarios that make bio-energy competitive—by direct or indirect subsidies or by valuing relevant externalities such as carbon emissions—could yield substantial benefits for rural and agricultural economies, both domestically in the U.S. and internationally. These benefits may evolve from increasing agricultural profitability,

increasing efficiency of agricultural resource utilization, and decreasing costs of subsidy programs. However, the scale and geographic distribution of these benefits, in relative and absolute terms, are dependent on the specific policy mechanisms employed. Policies supporting domestic production of feedstock or finished bio-energy products may advance domestic agricultural development at the cost of government spending efficiency. Such policies may also limit (in relative terms) opportunities for international bio-energy development, although the net effect on international agricultural economics may be dominated by positive price effects on conventional agricultural commodities. Policies that create incentives for low carbon energy systems will support rural and agricultural economic development to the extent bio-energy is competitive in providing low carbon energy products. They may also increase government spending efficiency (if they are substituted for some portion of current agricultural subsidy programs) and provide relatively greater support for international agricultural development—particularly if they are combined with decreasing trade restrictions.

Substantial analysis (far beyond the high-level discussion presented here) is required to judge the magnitude of potential benefits from bio-energy systems in terms of rural and agricultural development. Moreover, a variety of alternatives exists for advancing such policy objectives, suggesting that further analysis is required to understand the relative merits and economic efficiency of pursuing these objectives with bio-energy development. Absent such analyses, strong normative statements to advance rural economic development with bio-energy systems cannot be justified. However, the fact that such benefits exist at any significant level may be sufficient to tip the balance toward

policies promoting bio-energy development when valuation of better resolved economic benefits yields only modest net benefit. Integration of specific values for rural and agricultural development benefits, resolved by some future analysis, could support more aggressive bio-energy development policies than are supported by the analyses in Chapters 2 and 3.

4.1.3. Air quality

Industrial bio-energy systems can provide air quality benefits by generating relatively fewer emissions of specific pollutants than conventional energy systems. These lower relative emissions derive from the joint effects of biomass fuel properties and conversion technologies. As such, it is meaningful to consider potential air quality benefits of bio-energy systems independently for each application type. Accordingly, it is worth noting that the focus of this discussion is on industrial bio-energy systems and not, for example, on small-scale bio-energy use for indoor heating and cooking, which may be among the greatest air quality threats to human health in countries with developing economies [21].

In stationary power applications, bio-energy systems can yield emissions reductions for a variety of pollutants, particularly including sulfur, mercury, and nitrogen oxides. Sulfur and mercury emissions reductions evolve from the very low levels of these elements in biomass fuels. Accordingly, these emissions reductions can be achieved with nearly any conversion technology. However, as discussed in Chapter 2, within cofire applications,

sulfur benefits can be greater than predicted from fuel substitution alone. Emissions of nitrogen oxides can also be reduced with biomass-coal cofire; however, the magnitude and sign of this effect remains uncertain and the underlying mechanisms are not well resolved. Importantly, however, as discussed in Section 2.2.3, emissions reductions achievable by cofiring biomass appear insufficient to comply with limits prescribed in the Clean Air Act Amendments of 1990, the NO_x SIP Call, and CAIR. Moreover, except in niche applications where relatively low-cost biomass feedstock is substituted for high-sulfur coal, emissions reductions from cofire are not generally cost competitive with emissions allowances at current market prices. See Chapter 2 for a more detailed discussion.

In dedicated biomass power applications, potential air quality benefits depend on the technological baseline of comparison. A series of life cycle assessments by the National Renewable Energy Laboratory Biomass suggests that biomass IGCC systems can achieve substantial life-cycle average emissions reductions for sulfur and nitrogen oxides relative to current pulverized coal (“PC”) fleet average emissions (95% and 80%, respectively) [22, 23]. However, the same assessments indicate substantially different results in comparison with advanced PC technologies using low emission boiler systems (66% reduction for sulfur and a 27% *increase* for nitrogen oxides). Further, performance results from the Tampa Electric Company’s coal IGCC demonstration project in Polk Power Station Unit 1 suggest that there may be zero air quality benefit from biomass systems relative to advanced coal IGCC [24].

Biofuels can offer a somewhat different set of air quality benefits when substituted for (or blended with) conventional fossil transportation fuels. For example, bio-ethanol is currently used as a gasoline oxygenate to reduce incomplete combustion in motor vehicles. Use of oxygenates including bio-ethanol is mandated under Titles 1 and 2 of the Clean Air Act Amendments of 1990 for areas in non-attainment of National Ambient Air Quality Standards for carbon monoxide and ozone [25]. In addition, bio-ethanol use can reduce sulfur emissions, which may, in turn, reduce sulfur poisoning of exhaust catalyst systems with compounding emissions benefits [26, 27]; Fischer-Tropsch liquids, including those produced from biomass, can provide similar sulfur emissions benefits relative to conventional petroleum-based fuels [28].

These air quality benefits can make biofuels appear relatively attractive; however, they remain somewhat controversial. For example, deployment of emissions control technologies is primarily credited for motor vehicle contributions to improved ambient carbon monoxide and ozone levels, not fuel oxygenate blending [29, 30]. Moreover, bio-ethanol's lower vapor pressure tends to increase emissions of volatile organic compounds ("VOC"), creating a trade-off in pollutants that induced the State of California to relax its VOC emissions regulations in order to support increased use of bio-ethanol oxygenates for carbon monoxide and ozone abatement [29]. Finally, while potential sulfur emissions benefits from biofuels are relatively straightforward, transportation is responsible for only about 5% of U.S. sulfur emissions [31], suggesting that transportation fuels may not be the most effective target for advancing sulfur controls. Moreover, it is not clear that biofuels would compete effectively with fossil fuel alternatives (e.g., coal Fischer-

Tropshe liquids) capable of providing similar air quality benefits.

More generally, it is not clear that air quality benefits from bio-energy systems are sufficiently effective, cost competitive, or scalable to justify additional development on this basis alone. While policies targeting air quality benefits may open some niches for bio-energy systems (e.g., cofire where high-sulfur coal is displaced), it appears unlikely that they will motivate substantial increases in bio-energy utilization.

4.1.4. Energy security

Energy security has been an important driver behind bio-energy development since the oil shocks of the 1970's. Falling global oil prices in the 1980's combined, perhaps, with a growing sense of security through diverse global economic interdependencies in the 1990's reduced the perceived importance of energy security, somewhat. However, persistent political instability in major oil producing regions (particularly the Middle East), recent oil price increases (e.g., U.S. average domestic first purchase prices for crude oil more than doubled in real terms between 2001 and 2005 [32]), uncertain future prices (e.g., the range in EIA oil price projections for 2030 is nearly as big as the average of high and low price cases[33]), and the range of time frames projected for oil production "peaking" in non-OPEC countries suggests that national energy security will be an important dimension of bio-energy policy for many years to come [34]. In spite of this importance, however, developing meaningful values for energy security benefits is

fundamentally hard, confounding effective analysis and policy development.

Oil is of primary concern when considering energy security due to the relative concentration of oil production in politically unstable regions. Petroleum intensity has been declining in all sectors, as illustrated in Figure 4.1a; however, the transportation and industrial sectors remain strongly reliant on petroleum and dominate U.S. petroleum consumption, as illustrated in Figure 4.1b and 4.1c. Accordingly, these two sectors are most at risk from disruptions in U.S. oil supply. To the extent coal is used to produce synthetic fuels, the most obvious petroleum substitute other than biofuels, persistent oil supply interruptions and price instability may have spillover effects across multiple energy markets. However, this is likely a secondary concern in the American context, as domestic coal reserves are large and it will take many years (potentially decades) to mobilize resources sufficient to deploy synthetic fuel production at scales relevant to offset oil imports, during which time, coal production capacity may be scaled up to match the growing demand.

The key implication of this is that biofuels dominate other bio-energy applications in their ability to provide energy security benefits. Feasible scales of biofuels production, as discussed in Section 4.2.2, may limit the magnitude of these potential benefits; however, substitution of biofuels (and other petroleum substitutes) for oil could support increasingly diversified supply chains and reduce reliance on potentially unstable oil exporters with substantial energy security benefits.

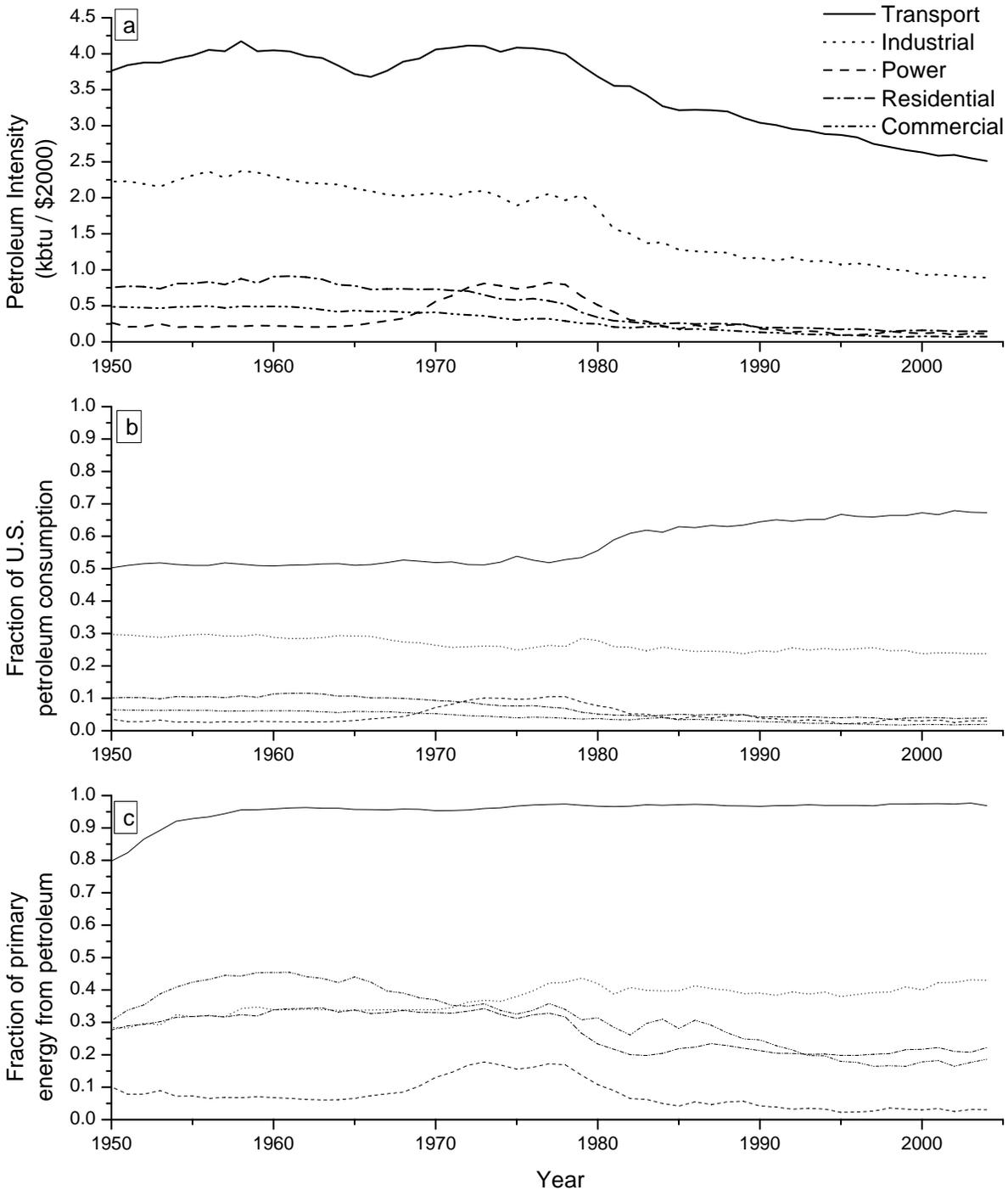


Figure 4.1. Sector-specific petroleum consumption: 1950-2004. Sector-specific U.S. petroleum consumption is plotted as a function of time. Panel (a) presents consumption (kbtu) normalized by gross domestic product (chained year 2000 dollars) to illustrate sector-specific petroleum intensity. Panel (b) presents consumption normalized by total U. S. petroleum consumption to illustrate each sector's share of consumption. Panel (c) presents consumption normalized by total primary energy consumed within each sector to illustrate each sector's relative reliance on petroleum. All data is from the Annual Energy Outlook [155].

While several approaches to estimating meaningful values for these energy security benefits are conceivable, they tend to be complex and highly uncertain. For example, it is plausible to estimate the costs associated with potential oil supply interruptions of various scales and durations. These cost estimates could then be multiplied by estimates of each event's probability of occurrence in each prospective year. These expected costs could then be discounted to the current year and summed to yield a net present expected value for energy security risks. However the uncertainty in each factor is large with compounding effects on uncertainty about the result. Moreover, it would not be possible to ensure that all potential supply disruptions were addressed. Alternatively, it would be plausible to estimate the costs associated with avoiding oil supply disruptions through military and diplomatic activities. However, uncertainty both in the relative probabilities of supply disruption (with and without these activities) and in the factoring of costs for these activities across their various objectives is also large with compounding effects across the calculation.

In addition to problems estimating the potential value of energy security benefits, there are also challenges in developing policy instruments to credit enhanced energy security within energy markets. Policy instruments capable of providing such credit are generally detached from the energy security benefit itself (unlike those associated with, for example emissions, which can be measured directly at the stack), and will therefore tend to be relatively blunt and inefficient.

These various challenges confound rigorous analysis of the magnitude of potential energy

security benefits from bio-energy systems. Moreover, to the extent energy security is the objective, biofuels would have to be considered with other petroleum substitutes, (including Fischer Tropsch liquids from coal) and other means of advancing energy security (including diplomacy and military intervention). It is plausible that biofuels could be cost-competitive with such alternatives at some level of production; however, biomass supply challenges, discussed in Section 4.2.2, suggest that coal-based solutions may dominate if petroleum is to be substantially displaced only to advance energy security objectives.

Despite these issues and the analytical limitations they impose, neither the challenges to understanding the value of energy security benefits from bio-energy (and their implications for the economics of bio-energy systems) nor the relative merits of advancing energy security with biomass (rather than coal, for example) preclude estimation of the costs associated with using bio-energy to advance specific energy security objectives. For example, imports from the Persian Gulf represented 17% of total petroleum imports to the U.S. in 2005, which averaged 13.5 million barrels per day [32]. Substituting these imports, equivalent to ~13 EJ annually, with biofuels appears *prima facie* to be a plausible energy security objective.

A rough estimate of the costs associated with making this substitution can be developed (with important caveats, discussed below) by comparing the biofuel producer costs presented in Table 3.4. with the costs associated with these petroleum imports. Assuming the cost of petroleum imports from the Persian Gulf are equal the average cost of imports

from OPEC (\$51.10 per barrel in 2005 [32]), and assuming all of these imports are used for gasoline production, the cost of gasoline from 2005 Persian Gulf imports is equivalent to ~\$13.4 per GJ at the refinery gate. This compares with ethanol producer costs of \$13 to \$15 per GJ and FT liquids costs of \$13 to \$14 per GJ, assuming no CCS integration. These relative costs imply that 2005 Persian Gulf petroleum imports could have been fully substituted with biofuels for a total net cost between -\$2 and \$8 billion per year.

As a point of reference, \$8 billion is equivalent to 1.4% of \$570.4 billion in U.S. federal security-related discretionary funds approved for 2007 (including \$99.6 billion in additional funds requested to support the Global War on Terror reduces the proportion of security-related funding to ~1.2%) [35]. This is a relevant point of comparison because some portion of security-related funding is arguably utilized to advance energy security objectives. The magnitude of this as a proportion of total security spending is not clear; however, at any significant scale it represents a subsidy to the petroleum industry or, conversely, a cost that is not internalized within the energy market or reflected in the prices of petroleum products.

It is reasonable to assume that energy markets would be substantially different with this level of biofuel production and with the associated reduction in petroleum demand.

Assuming that oil prices fell to \$30 per barrel and that biomass feedstock prices increased from \$50 per dry ton (assumed in the biofuel production costs presented in Table 3.4) to \$75 per dry ton, the total net cost would be between \$42 and \$52 billion per year, equivalent to between 7 and 9% of security-related federal discretionary funding

approved for 2007 (or 6 to 8% including the additional funding request) [35].

The quantity of biomass required to support this level of biofuels production, based on the range of efficiencies presented in Table 3.4, is between 11 and 13 EJ per year. This is roughly four times more than has been projected could be available from energy crops in the near term with farm gate prices of ~\$44 per dry ton [36], but well within the range of biomass supply that has been projected could be available for energy purposes by mid century [17], as presented in Table 4.1 of Section 4.2.1.

The calculations presented above should be interpreted carefully, as they are subject to a number of important caveats. For example, petroleum consumption and imports from the Persian Gulf may be substantially different by the time biofuels production could be scaled up to the levels implied above. Future petroleum prices are highly uncertain, particularly for scenarios with this level of biofuel substitution. Technologies for ligno-cellulosic ethanol and FT liquids production are (very) likely not ready for commercial deployment at these scales. Finally, ligno-cellulosic biomass feedstock supply and its broader economic impacts are not well understood for these scales of production, so the total net cost results have a relatively high degree of uncertainty. Recognizing the limitations imposed by these caveats, the calculations above do suggest that biofuels could make potentially important contributions towards energy security objectives at costs that may be reasonable in the context of federal security spending.

4.1.5. Sustainability

Biomass and other renewable energy systems have long been promoted for advancing sustainability, and policies supporting these systems frequently include increased sustainability among their stated objectives. While this policy objective is intuitively appealing and important politically, its use as a valued attribute in economic analysis is extremely complex. First, the definition of sustainability is complex and evolving; one version is included below as an illustrative rather than definitive example:

Sustainability is an attempt to provide the best outcomes for the human and natural environments both now and into the indefinite future. It relates to the continuity of economic, social, institutional and environmental aspects of human society, as well as the non-human environment. It is intended to be a means of configuring civilization and human activity so that society, its members and its economies are able to meet their needs and express their greatest potential in the present, while preserving biodiversity and natural ecosystems, and planning and acting for the ability to maintain these ideals in a very long term. Sustainability affects every level of organization, from the local neighborhood to the entire planet. [37]

The United Nations 2005 World Summit Outcome Document characterizes the three components of the related concept of sustainable development as economic development, social development, and environmental protection [38].

Bio-energy systems arguably advance some dimensions of sustainability. To the extent harvested biomass is effectively replanted, it can represent a renewable energy resource. Rural economic development, improvements in certain dimensions of environmental quality, and energy security, as discussed elsewhere in Section 4.1, are also relevant in this context. However, the contributions of bio-energy toward sustainability are not all

positive. For example, there are significant environmental costs associated with intensive biomass production, as discussed in Section 4.1.6 below, which may detract from sustainability objectives.

The process by which these various factors might be integrated into a broader measure of sustainability consistent with its conception in the definition above is not clear. More generally, the concept of sustainability is too broad, the potential metrics too diverse, and the relative values too uncertain to allow systematic analysis of the performance of bio-energy systems in this dimension. Absent analysis of the efficacy and economic efficiency of advancing sustainability with bio-energy, strong policy recommendations to that effect cannot be justified.

4.1.6. Ecological trade-offs from biomass production

It is generally well established that fossil fuel extraction, transportation, and energy conversion yield various types of ecological damage. Bio-energy substitution may therefore be thought to yield significant benefits; however, bio-energy systems will also precipitate substantial ecological damages, particularly from agricultural activities for biomass production [39]. While some types of such damages can be at least partially mitigated with modified agricultural practices (e.g., top-soil erosion) [39], others (e.g., habitat losses from conversion of wild lands) are generally persistent and compounded by other environmental stresses (e.g., urban and suburban sprawl). Some level of bio-energy

can be supported by diversion of existing biomass flows elsewhere in the economy (e.g., urban wood wastes and agricultural or forestry residues); however, large-scale bio-energy development and widespread utilization generally imply increased production with associated increases in ecological damages. The implication is that bio-energy substitution for fossil fuels yields complex ecological trade-offs rather than strict abatement. Evaluation of these trade-offs require valuation across diverse types of ecological damages, which is inherently difficult and subject to large uncertainties.

This issue is further complicated by the fact that biomass production for bio-energy application can be accomplished at various intensity levels, where production intensity is inversely related to the area required for any particular level of production. Production in the tradition of the U.S. Forest Service, with its mandate to support multiple land uses and sustained yields, represents a plausible example at the low end of this intensity spectrum; whereas production in the tradition of industrial agriculture represents a relatively high-intensity example. Evaluating the relative merits of production systems across this spectrum also requires valuation of diverse types of ecological damages and services, which is, again, inherently difficult and highly uncertain. However, geographically-concentrated, high-intensity production systems may be ecologically preferred due to their reduced network externalities (e.g., habitat scarcity and fragmentation) [40].

Interestingly, to the extent that carbon mitigation is motivated by concerns related to the effects of climate change on ecological systems, it would appear that biomass-based

mitigation should theoretically enable one to consider the potential trade-offs in these damages directly. Specifically, the ecological damage caused by a marginal unit of land dedicated to biomass production could be compared with the ecological protection of climate change averted by the associated biomass-based mitigation. Such a comparison is complicated by the relative distributions of these damages: damage from biomass production is generally concentrated around the area of production, whereas damage averted by climate change mitigated is globally distributed. Moreover, complex tradeoffs across different types of damages may compromise meaningful analysis. However, it is insightful to consider these theoretical trade-offs at a high level.

Consider first a case approximating the current situation in which there is zero (or at least very limited) dedicated industrial bio-energy crop production and similarly zero carbon mitigation. It is plausible that in this case, incremental bio-energy crop production could displace acreage currently responsible for surplus food production. As such, the marginal ecological damage of shifting one acre of agricultural production from one crop to another should be close to zero, or possibly negative, as bio-energy crops may be less damaging than many food crops. In contrast, the marginal damage avoided by this acre's worth of mitigation is arguably large, as it can be credited with avoiding the last increment of ecological climate damage (climate damage up through this last increment will still occur, absent other mitigation efforts). Climate damage functions plotted as a function of total emissions are widely considered to be non-linear with slope concave upward, as in Figure 4.2 [18]. The last increment of damages should therefore be relatively large. The implication of this (very) simplistic comparison suggests that net

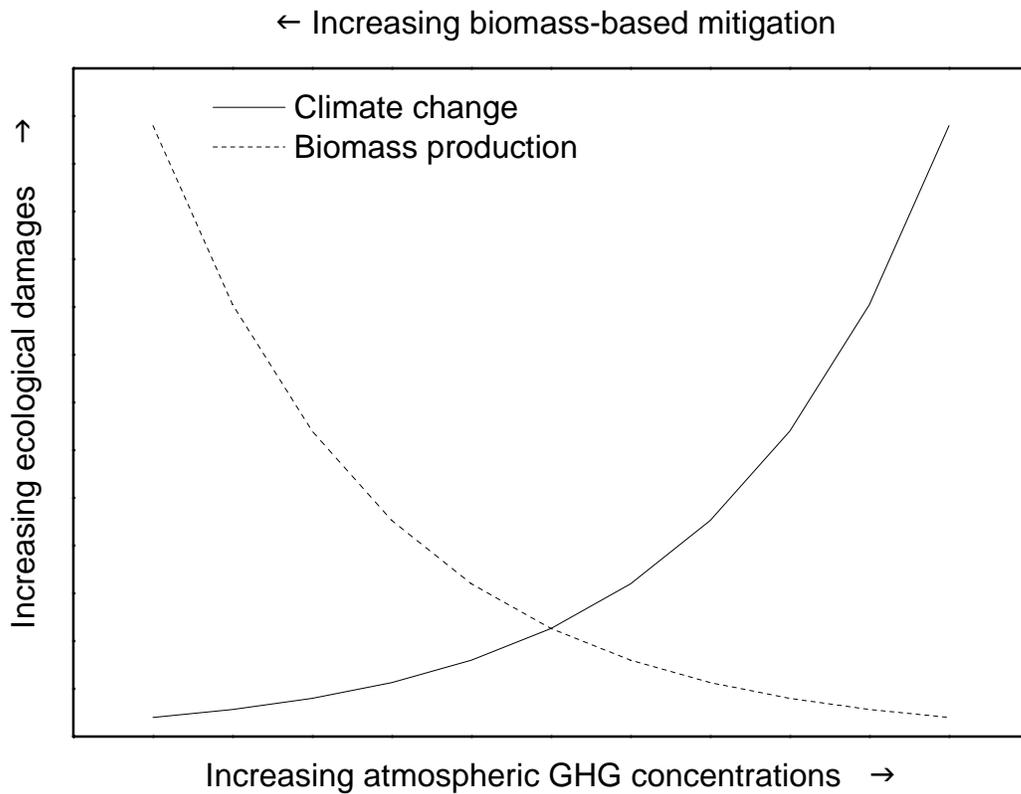


Figure 4.2. Theoretical ecological damage functions: Climate change and biomass production. Both theoretical damage functions are plotted with curves that are concave upward due to compounding damages and network externalities, e.g., population effects from increasing habitat fragmentation and scarcity. The damage function for biomass production assumes that biomass is used for carbon mitigation resulting in atmospheric GHG stabilization at concentrations lower than what would be achieved absent biomass-based mitigation. The damage functions are drawn symmetrically for simplicity only and are not to scale. The intersection of these curves represents the theoretically optimal level of biomass-based mitigation from an ecological perspective, balancing damages from climate change and biomass production.

ecological benefits may be realized with some level of energy crop production.

Now consider how the relative magnitudes of these ecological damages evolve with joint development of bio-energy utilization and carbon mitigation. Increasing biomass production will eventually require conversion of wild land to production, and the magnitude of ecological damages from increasing wild land conversion will likely grow non-linearly due to network externalities (e.g., increasing habitat scarcity and fragmentation). In contrast, the magnitude of marginal climate damages avoided from expanded use of energy crops should be decreasing with increasing mitigation (moving down the curve from right to left in Figure 4.2). At the limit, conversion of the last acre required to fully mitigate climate change with bio-energy should cause relatively large direct ecological damage but avoid nearly zero damage from climate change. Some optimal level of biomass-based mitigation should therefore exist from an ecological perspective where marginal ecological damages induced from biomass production equal marginal damages avoided from mitigated climate change. The key issue is, therefore, in defining the optimal levels of bio-energy production and climate mitigation.

Note: the effects of other mitigation options have been ignored in this discussion. In the extreme case, where GHG emissions are fully mitigated by non-biomass strategies, there would be zero climate benefit to bio-energy crop production and the optimal level of production would be zero.

4.2. Key development challenges

Several important challenges to development have limited adoption of industrial bio-energy systems and, therefore, the extent to which the various potential benefits, discussed in Section 4.1, have been advanced with bio-energy. Specifically, these include challenges associated with biomass supply, the economics of mature bio-energy conversion systems, the relative immaturity of advanced technologies (with potentially attractive economic performance), and the general lack of technical experience with biomass systems within organizations dominating production in the energy sector.

4.2.1. Biomass supply.

Biomass supply issues both hamper near-term deployment and provide fundamental limits on long-term contributions from bio-energy systems. Supply issues and their implications are numerous but stem from a few basic factors. The first is the dependence of biomass supply on biological production systems, which must be geographically distributed (due to the energy density of insolation per unit area), and tend to be both temporally variable and prone to interruption from natural phenomena (including unfavorable weather conditions, pest outbreaks, or fire). A second factor is that low energy and bulk densities of biomass fuels generally yield high transportation costs. This

tends to create relatively inefficient, locally-oriented biomass fuel markets. Market inefficiencies may create challenges for both suppliers and facility managers as relatively small changes in local supply may cause dramatic swings in fuel prices. Even with well coordinated supply chains, uncertain yields and biomass production risks from natural phenomena magnify financial risks of fuel price sensitivity to local supply.

These factors interact in other ways, as well. One effect is to limit the scale of bio-energy projects because increasing capacity is associated with increasing transportation distance (the more biomass you need, the further you need to go to get it) and therefore increasing fuel costs; this appears to be a fundamental driver behind the relatively small scale of modern bio-energy facilities (compared with fossil fuel power facilities). Small scales are, in turn, largely responsible for the relative inefficiency of these facilities, increasing specific fuel costs. This is because high efficiency energy conversion technologies (e.g., with high operating steam temperatures and pressures typical of modern coal-fired power plants) are generally only economical at large scale [41].

Finally, biomass fuel markets are generally immature and under-developed—e.g., the substantial underutilization of currently-available biomass residues [42]. This may create certain challenges as development of advanced technologies approach commercial readiness and deployment decisions increasingly hinge on biomass supply chains and fuel prices. Deployment of bio-energy systems at scale will, therefore, require concurrent development of feedstock supply chains and conversion technologies until biomass fuel markets mature and prices can be reliably forecast.

In addition to the challenges for supply chain management, these issues impose fundamental limits on feasible scales of production. These limits are typically defined by biomass yields [$\text{t ha}^{-1} \text{ yr}^{-1}$] and the availability of key inputs to agricultural production, as energy crops play a major role within most projections of large scale bio-energy futures. In this context, land area is arguably the binding constraint on production, due to the diverse and compelling competitive pressures for available land resources, including particularly food production. However, optimal levels of production may be substantially below theoretical maximums due to environmental, economic, and social considerations. As discussed in Section 4.2.2, maximizing production may, for example, damage or otherwise reduce the extent of current ecosystems, reduce the biodiversity of those ecosystems, compromise environmental services they provide (e.g., regulation of clean water supplies), and pressure rural communities to adapt to radically changed environments.

While these constraints are widely appreciated, feasible scales of biomass production within the limits they imply are not well understood. Estimates of supply capacity vary by more than an order of magnitude within individual studies, due to uncertainty in parameters related to *inter alia* land availability, such as population growth and the resource intensity of future food supply chains [8]. Strong population growth, global adoption of meat-rich diets, and minimal gains in food production efficiency will likely leave little or no agricultural land for bio-energy feedstock production; however, modest population growth, decreasing meat intensity of diets, and strong gains in food production

efficiency may open substantial area for energy crops [8]. Substantial uncertainty in the long-term trends of these parameters will likely persist.

Comparison across analyses is further confounded by the alternate analytical objectives (e.g., determination of the technically feasible supply, of the economically viable supply, or of the ability to meet projected demand), approaches (e.g., survey of potential land availability, economic analysis of expected evolution in agricultural land uses under projected bio-energy market conditions, evaluation of resource availability to meet demand projected by coupled energy or economic models), and associated assumptions (e.g., yields, land classes available for biomass production, residue availability, technological performance, and economic assumptions) adopted within individual analyses [43].

In spite of this uncertainty in the potential scales of future biomass supplies for energy purposes, it is clear that bio-energy contributions to relevant policy objectives will be constrained by feedstock supply, even if technical and economic challenges are overcome. For example, while biofuels may become cost-competitive with conventional fuels (even absent climate-motivated policies), it appears unlikely that they will be capable of fully replacing conventional fossil fuels. To appreciate this, Table 4.1 presents the results of calculations integrating bio-energy feedstock supply estimates from the literature with the modeling results developed in Chapter 3. The supply estimates presented in this table are intended to be representative of the types of estimates in the literature, as described in the table caption. No judgments are made regarding the relative

Table 4.1
Estimates of potential bio-fuel supply

<i>Projection basis</i>									
Geographical area	United States		United States		Global		Global		
Biomass production estimate source	[15]		[17]		[44]		[8]		
Time frame	5 years		2050		2050		2050		
Estimate type	Min	Max	Min	Max	Min	Max	Min	Max	
<i>Biomass supply</i>									
Potential biomass supply (Mt yr ⁻¹)	87	171 ^a	506	1,236 ^b	2,474	32,143 ^c	1,737	80,714 ^c	
Potential biomass supply (EJ yr ⁻¹)	1.2	3.2 ^c	7.1	23.5 ^c	47	450 ^d	33	1,130 ^e	
Land dedicated to energy crop production (Mha)	7.9	17.0 ^a	0.0	24.3 ^f	0	745 ^d	0	4,280 ^g	
Percent of current agricultural land	4%	10% ^h	0%	14% ⁱ	0%	13% ^j	0%	74% ^j	
<i>Bio-fuel supply</i>									
Potential bio-fuel supply (EJ yr ⁻¹)	0.5	1.3 ^k	2.8	9.4 ^k	18.8	180.0 ^k	13.2	452.0 ^k	
Fuel demand (EJ yr ⁻¹)	21	21 ^l	35.8	35.8 ^m	124	496 ⁿ	336	336 ^o	
Percent of demand potentially met with biomass	2%	6% ^p	8%	26% ^p	15%	36% ^p	4%	134% ^p	
<i>Transportation sector mitigation potential</i>									
Fossil CO ₂ emissions (Mt CO ₂ yr ⁻¹)	1,313	1,313 ^q	2,287	2,287 ^r	7,936	31,635 ^q	20,604	20,604 ^s	
Percent mitigated with substitution only	2%	6% ^t	8%	26% ^t	15%	36% ^t	4%	134% ^t	
Percent mitigated with substitution and offsets (CCS)	8%	21% ^u	28%	86% ^u	44%	148% ^u	12%	565% ^u	
Percent mitigated with offsets from bio-power (or H ₂) ^v	11%	21% ^v	37%	89% ^v	51%	168% ^v	14%	646% ^v	

Table 4.1 --- Continued

Notes

^aConsiders only potential energy crops, as described in [15].

^bThe minimum value includes 124 Mt from currently unexploited forestry resources and 382 Mt from currently unexploited agricultural resources; the maximum value includes 332 Mt from forest resources - 129 Mt of which is currently used in the forest products industry - and 904 Mt from agricultural resources, as described in [17].

^cAssumes average heating values of 14 and 19 MJ/kg.

^{d, e, f}From [44], [8], and [17], respectively.

^gThe minimum value includes only 430 Mha degraded agricultural land; the maximum value includes 3.7 Gha primary agricultural land plus 580 Mha degraded agricultural land, as described in [8].

^hCalculated by dividing the dedicated land area by 174 Mha of US agricultural land reported in [15].

ⁱCalculated by dividing the dedicated land area by 182 Mha of US agricultural land reported in [17].

^jCalculated by dividing the dedicated land area by 5 Gha global primary agricultural land and 760 Mha global degraded agricultural land reported in [8].

^kCalculated by multiplying the specified biomass supply by an assumed bio-fuel conversion efficiency of 40% (See Table 3.6).

^lReference projection for motor gasoline consumption in 2010 as described in [45].

^m2x motor gasoline consumption in 2003, as described in [45].

ⁿLiquid fuel consumption, as described in [44].

^o2x oil consumption 2002, as described in [47]; Note that bio-fuels may not be suitable substitutes for all petroleum products.

^pCalculated by dividing the potential biofuel supply by the fuel demand.

^qLinearly scaled from fuel demand based on net emissions factor implied by the ratio of US 2003 motor gasoline consumption, as described in [45], to US 2003 motor vehicle emissions as described in [46].

^r2x motor gasoline emissions as described in [46].

^s2x CO₂ emissions from oil in 2002 (table A11) from [47].

^tSet equal to the percent of demand potential met with biomass above.

^uCalculated by multiplying the potential biomass supply (Mt yr⁻¹) by an assumed mass fraction carbon in biomass of 50%, multiplying by an assumed carbon capture rate in production of 50 to 60%, converting to MtCO₂, dividing by the fossil CO₂ emissions (MtCO₂ yr⁻¹) and adding the percent mitigated with substitution only.

^vTransportation-sector mitigation potential of emissions offsets only from heat, electricity, or hydrogen production with 90% carbon capture. Calculated by multiplying the potential biomass supply (Mt yr⁻¹) by an assumed mass fraction carbon in biomass of 50%, multiplying by an assumed carbon capture rate of 90%, converting to MtCO₂, and dividing by the fossil CO₂ emissions (MtCO₂ yr⁻¹).

merits of the alternate types of estimates and their associated underlying assumptions or of the specific values presented here.

Several robust conclusions are possible from the results in Table 4.1. Fractional contributions from biomass may be substantially larger at a global scale than a domestic one (e.g., within the U.S. alone). The implication is that efficient markets for international trade in bio-energy products (or feedstock) could substantially increase the relative scale of domestic utilization of biomass primary energy in developed countries. This may be particularly important if energy security is a dominant motivation for expanded deployment of bio-energy systems. Note that such markets are currently confounded by trade restrictions protecting domestic agricultural production, as discussed in Chapter 4. Even with efficient trade, however, biomass production will have to be high and realize at least some relatively optimistic assumptions embodied in the larger

biomass resource estimates from the literature if bio-energy products (e.g., biofuels) are to substantially displace corresponding fossil energy products.

In addition, the calculations in Table 4.1 highlight the extent to which CCS integration can improve the mitigation potential of available biomass resources. For example, consistent with results presented in Table 3.8, the transportation sector mitigation potential of options including CCS-derived emissions offsets appears to be greater than that of biofuel substitution alone by a factor of three or more. One implication of this additional leverage is that substantial mitigation of transportation sector emissions may be possible, even with the relatively low biofuel substitution rates implied by some of the more conservative estimates of potential feedstock supply. At the limit, the calculations indicate that the transportation sector mitigation potential of emissions offsets from power sector applications is at least as great as that of offsets plus fuel substitution from biofuels applications. This is due to the substantially higher carbon capture rates achievable in power applications and ignores the mitigation benefits from fuel substitution in the power sector.

In theory, the results presented in Table 4.1 may be viewed as sufficient to support a claim that biomass-CCS represents a “silver-bullet”, or complete solution, for GHG mitigation in the transportation sector (and beyond), regardless of the specific technological route. Such a claim is not endorsed here due to the scale of uncertainty in the feedstock supply estimates, the diverse assumptions embodied in those estimates, the substantial supply challenges beyond production capacity (see Sections 4.1.6 and

discussion above), the ethical issues associated with maximizing biomass production, the relative likelihood of success compared with a more diversified portfolio approach to mitigation, and the uncertain costs of such a strategy.

While not necessarily a silver bullet, these results, combined with the general arguments presented throughout this chapter and Chapters 1 and 3, do suggest that a transportation sector mitigation strategy leveraging biomass-CCS is at least as plausible as one based on hydrogen—the later of which is often presented as the dominant (if not only) option for carbon-neutral transportation [48]. Both strategies face important challenges, including those associated with biomass supply, energy conversion, and CCS viability for biomass-CCS and those associated with primary energy sourcing (e.g., fossil with CCS, nuclear, or renewable), energy conversion technologies, transport & distribution infrastructure, end-use technologies (e.g., the potential risks from high-pressure on-board storage systems and development requirements of alternatives), and CCS viability (for fossil primary energy sources) for hydrogen. The relative economic performance of these strategies is also uncertain—reflecting uncertainty in future technological performance and market conditions. Substantial further analysis is required to understand the relative merits of these strategies.

That said, the ability of biomass-CCS to leverage existing fuel transport and distribution infrastructures and end use technologies provides several important advantages. In particular, it supports incremental growth in biofuel deployment, compatible with many emissions trajectories aimed at stabilizing long-term atmospheric GHG concentrations at

desirable levels [3, 4]. In contrast, hydrogen-based options typically imply wholesale (if potentially step-wise) conversion of transportation energy infrastructures and end-use technologies, suggesting many decades may be required for deployment [49]; the delayed mitigation implied could substantially increase risks from climate damages.

While the relative merits of biomass-CCS and hydrogen strategies for transportation sector mitigation are relevant, these options are not mutually exclusive. For example, biomass energy systems, with or without CCS, could represent an important stepping stone toward a hydrogen economy, by supporting interim mitigation objectives until hydrogen systems can be fully deployed. In such a scenario, the benefits of biomass for incremental and near-term deployment can be gained without sacrificing any potential long-term advantages of hydrogen. Moreover, biomass supply chain development could be leveraged to provide carbon neutral (or negative) hydrogen production (with CCS) if and when hydrogen-based options are employed. Note that negative emissions, and associated climate benefits, from biomass used for hydrogen or power generation with CCS are likely greater than for biofuels with CCS as more biomass carbon—90% or more—could be captured (See Table 3.7).

4.2.2. Financial Performance.

The financial modeling results in Chapters 2 and 3 are indicative of bio-energy systems more generally. Note, in particular, that it is sensible to consider bio-energy financial

performance on a product or market specific basis. For example, biomass-derived heat and power is, typically, only cost-competitive in niche applications where fuel costs are low or negative, such as in timber-products industries [41]. In contrast, the competitiveness of biofuels hinges more on the price of oil than on the price of biomass. This distinction is driven largely by the relative diversity of supply across these energy markets. Specifically, electricity markets can balance supply across multiple technologies and prime movers with evolving market conditions to provide some level of price stability. In contrast, the prices of liquid fuels are generally coupled with oil prices; although it is plausible that this situation may eventually change with increasing deployment of competitive petroleum substitutes.

Oil price is a dominant factor in the financial and economic performance of biofuel production pathways. For example, in the wood ethanol production system without CCS modeled in Chapter 3, mitigation costs move linearly from \$418 to \$29 per tC with oil prices between \$27 and \$54 per barrel (see Table 3.4). As a point of reference, mitigation costs only move from \$258 to \$446 per tC with delivered feedstock prices between \$27 and \$54 per t_{biomass} (with oil prices at \$27 per barrel). This example suggests that the mitigation costs of biofuels are generally twice as sensitive to oil price as to feedstock price. (Across all the systems modeled in Chapter 3, mitigation cost sensitivities to oil price are greater those to feedstock price by factors ranging from 1.4 to 2.6.) Moreover, the mitigation costs listed in Table 3.4 with oil prices of \$54 per barrel suggest that biofuels without CCS could be cost competitive with gasoline if oil prices are high. In this context, it should not be surprising that the relatively recent rise in oil

prices, beginning around 2001, appears to have enhanced opportunities for biofuels as a petroleum substitute, evidenced by the relatively large number of new production facilities in development [19, 50].

Note, however, that the capital-intensity of production and remaining R&D required for deployment of emerging technologies (including, for example, production from ligno-cellulosic feedstock) suggests that medium and longer term oil price expectations should dominate current market prices in biofuel development and deployment decisions.

Accordingly, the potential competitiveness of biofuels remains uncertain as oil price forecasts over relevant time scales are subject to substantial uncertainties, for example in future supply and demand and in the potential effects of petroleum substitutes within similar time horizons. Importantly, however, even if biofuels become cost-competitive as a petroleum substitute climate-motivated policies—e.g., those that define market values for negative carbon emissions—will be required to stimulate CCS integration with production systems and maximize potential climate benefits from biofuels.

Widespread deployment of biomass heat and power systems faces more fundamental financial challenges in competing with conventional coal and natural gas technologies. The first is from fuel costs, which have historically ranged from 2 to 4 \$/GJ for biomass and natural gas and from 1 to 2 \$/GJ for coal [51]. The relatively high cost of biomass is compounded by the relative (in)efficiency of modern dedicated bio-energy conversion technologies, which typically range from 16% to 25% (HHV), compared with 33% to 40% (HHV) typical of modern coal systems and 35% to 50% (HHV) typical of modern

natural gas systems [41, 52-54]. The combined effect of fuel price and conversion efficiency makes the fuel cost component of electricity roughly four times greater for biomass than coal and more than two times greater for biomass than natural gas.

It is reasonable to assume that the economics of bio-energy systems will improve as advanced technologies mature. For example, the similarity in energy conversion technologies for biomass and coal suggests that conversion efficiencies for biomass could approach those for coal over time. Such gains cannot, however, address the difference in fuel costs, and it is very unlikely that conversion efficiencies for bio-energy could ever approach those of natural gas, due to fundamental advantages of gaseous fuels. Note that these advantages also yield capital cost savings of a factor two or more in favor of natural gas [55].

For these reasons, it appears that (in addition to development of advanced technologies and efficient biomass fuel markets) policy instruments to effectively credit non-financial economic benefits will generally be required to overcome the financial challenges of bio-energy systems. This may be somewhat less relevant for biofuel systems if oil prices remain near their recent highs or continue their upward trend from strong global economic growth. (As indicated by the results in Figure 3.9, with continued development, biofuels may be cost competitive with gasoline in scenarios with oil prices persisting above 54 \$/bbl.) However, technology, market, and policy development will generally be required to optimize realization of non-market economic benefits from bio-energy, including those associated with anthropogenic climate change, even with cost-

competitive biofuels.

4.2.3. Technological maturity

Advanced bio-energy conversion technologies, including those evaluated in Chapter 3, are frequently promoted as offering substantially improved technical, economic, or environmental performance relative to currently deployed options. The enthusiasm by some for such new technologies can be so strong as to create frustration at the fact that widespread deployment at scale is not already underway. In spite of this enthusiasm, however, it seems to be generally understood that advanced bio-energy technologies (e.g., IGCC and ligno-cellulosic ethanol production) are not yet fully mature and substantial uncertainty remains in both technical and economic dimensions of their performance.

The technical performance of advanced technologies is often evaluated and characterized through computer simulation and optimization of technical components with coupled economic models. However, uncertainty in the technical parameters of such modeling efforts is often not well characterized. Simulation modeling results are typically compared and calibrated with empirical results; however, careful evaluation of the modeling basis and subjective judgments of the modeling team are often required to evaluate uncertainty in technical performance characteristics of simulation modeling results. Further, even with relatively high confidence in the technical characteristics of

novel system components, uncertainty in economically sensitive technical assumptions, such as feasible scales, may remain.

Economic model uncertainty is often dependent on the level of detail included in the analysis. To some extent, this can be characterized by applying process engineering analysis standards and procedures. However, uncertainty in the cost of novel system components may be large, and the modeling tools used to balance such uncertainty, including capital allocations for contingencies, are often relatively blunt. Moreover, many economic analyses of advanced technologies, including those in Chapters 2 and 3, do not fully leverage these techniques because they aim to characterize costs associated with construction of an “nth” plant, benefiting from several years of further development and many earlier deployments. In such analyses, component cost estimates generally do not include the premiums required for customized design and manufacture, and allocations for project contingencies are generally minimized. In addition, these types of models generally do not integrate effects from potentially-coupled macro-economic changes. An example relevant to the analyses developed in Chapters 2 and 3 is that capital cost increases due to policies defining economy-wide carbon prices, which may be a prerequisite for deployment of these energy systems, have not been effectively integrated.

These issues do not suggest that the results from such engineering-economic analyses of advanced technologies are flawed or overly optimistic—these methods are used throughout analyses presented in this thesis, as well. This discussion serves primarily to

highlight the caveats (typically stated explicitly within the analyses themselves) that significant uncertainty in the performance of novel systems and system components often remains and further development is required before the projected technical and economic performance can be assured. However, too often it seems that these caveats are not appropriately reflected in the *interpretation* of modeling results. This can yield presentation of bio-energy economics and feasibility assessments that are unrealistically good (or in some cases bad) and frustration by some at the current status and pace of industrial bio-energy deployment. These problems may stem from inconsistent appreciation for the implications of such caveats on industrial deployment of capital-intensive technologies or from advocacy biases. Regardless of the underlying reasons, however, more systematic analysis that compares biomass technologies with other means of achieving similar objectives would be useful in understanding the relative technological risks across various options.

In addition to uncertainty in the details of technical and economic performance, advanced technologies are often subject to uncertainty in their social acceptability and potential unintended consequences of their deployment for the economy. For example, public acceptance of geological storage of CO₂ captured from industrial energy systems—required for deployment of the technologies evaluated in Chapter 3—is far from certain. It will hinge on, among other things, public perceptions of risk to human health, welfare and the environment. Similarly, questions regarding the implications of energy crop production for food security and prices have been raised, and while economic analyses suggest that substantial quantities of bio-energy could be generated without affecting

food prices [15, 16], public confidence in and social acceptability of such conclusions remain uncertain.

4.2.4. Industrial inexperience and uncertainty with biomass fuels

In addition to deployment barriers from more general technological immaturity, bio-energy systems will likely face additional barriers from inexperience with biomass fuels within organizations dominating production in the energy sector. Plant owners and operators can be expected to be highly averse to operational risks in the context of regulatory intensity, capital intensity, increasing efficiency, and increasing competition within energy markets, combined with uncertainty in future environmental controls and market deregulation. Within this context, the perceived operational risks from biomass fuels and related technologies may be a strong deterrent to deployment, even for relatively mature technologies with positive economic performance expectations, such as cofire of biomass residues with coal, as discussed in Chapter 2.

Biomass fuels can create several unique operational challenges with associated financial risks. Feedstock procurement challenges, related to the biomass supply issues described above, create several types of risks. Delivered fuel costs are an obvious example, but supply challenges also compromise projections of plant utilization, with strong financial implications. Temporal variability and catastrophic risks to local supply (e.g., from fire or massive pest outbreaks) have the potential to reduce utilization, and even relatively

minor shortfalls in local supply could have strong price effects or limit operational capacity.

Specific biomass fuel properties can create technical challenges, as well. Fuel feeding can be compromised by the fibrous nature of certain feedstock types, and compounds present even in relatively small quantities can create or significantly magnify problems of corrosion, slagging, fouling, deposition, bed agglomeration, or catalyst poisoning [56-58]. It appears that each of these various risks should be manageable—with potentially higher costs—by judicious selection of conversion technologies, fuels, operational parameters, and supply chain management strategies. However, operational experience will be required both to ensure effective management of these risks and to inform risk perceptions throughout the energy sector. In the meantime, the net benefit of deploying bio-energy technologies will have to be sufficiently large to overcome the potentially large negative value of operational and financial risks integrated across the risk preferences of plant owners and operators.

4.3. Policy frameworks relevant to bio-energy systems

Policy incentives will likely be required to overcome the challenges to deployment discussed above and realize the potential benefits of bio-energy systems. These incentives may be structured to provide short-term stimulus to overcome technological challenges and develop industrial experience, or to assign longer-term value for non-

financial economic benefits, including CO₂ abatement, energy security, and rural economic development. Several such policies targeting bio-energy and renewable energy more generally have been in place in the United States since the energy crisis of the 1970's [59, 60]. Continuation and expansion of these policies will tend to extend support for bio-energy development and move advanced technologies closer to commercialization. In general, however, the most efficient mechanisms for promoting the potential *benefits* of bio-energy (without technological prejudice) define an even value for such benefits across the economy—e.g., through emissions taxes or cap and trade systems.

Market-based policy frameworks appear particularly appropriate in the energy sector where cap and trade systems have been successfully applied in controlling emissions of sulfur and nitrogen oxides. The economic efficiency of such frameworks stems from the competitive environment they create for providing the targeted benefits (e.g., emissions reductions). As a result, their stimulus for bio-energy development depends on bio-energy's competitiveness in providing these benefits. The general arguments in Sections 4.1.1, 4.1.2, and 4.1.4 together with the modeling results in Chapters 2 and 3 suggest that bio-energy systems may compete effectively within such frameworks aimed at providing climate, energy security, and rural economic development benefits. Specific market niches may also exist, in which bio-energy systems could be competitive in advancing air quality or other policy objectives.

The subsections below discuss several policy frameworks relevant to bio-energy

development and to biomass-based carbon mitigation. Specifically, Section 4.3.1 provides a high-level overview of these frameworks and Section 4.3.2 discusses specific instruments that have been proposed or enacted in the U.S. at the federal level. State level initiatives have had an important role in the U.S.; however a comprehensive review of these policies is beyond the scope of this analysis.

4.3.1. Policy frameworks.

Several diverse policy frameworks have been implemented or proposed to support bio-energy technologies. These range from direct funding programs—such as government-sponsored research and development projects and grants supporting demonstration of specific technologies (e.g., the BCL/FERCO technology modeled here)—to programs designed to credit (or tax) non-financial benefits (costs)—including renewable energy tax credits, incentive payments, and portfolio standards, as well as air quality and climate-motivated cap-and-trade or tax systems [61, 62]. These various frameworks are generally applicable; however the discussion below and the particular examples provided reflect a specifically American perspective.

Direct government-funded research programs have played important roles in bringing industrial bio-energy technologies to their current level of maturity. Consistent with the development pathways of many modern energy technologies, research funded by government agencies in the U.S. and abroad (as well as through public-private

partnerships) have contributed significantly to bio-energy technology development, including identification of technological pathways, design and testing of key system components, development of integrated engineering-economic analyses, and financing of demonstration projects. Outputs from such efforts have subsequently been used to support further analyses in both academia and the private sector and emerging technologies have been licensed to industry for commercialization. (These roles are reflected in the development trajectories of many technologies, including, for example the gasification systems modeled in Chapters 3 [22, 63-66].)

Research and development funding continues to play important roles in bio-energy development; however, the long-term viability of specific technologies will generally be determined in the context of competitive markets. Therefore, as bio-energy technologies move toward commercialization, policies that support markets for non-financial benefits will become increasingly important. One class of such policies specifies certain technical characteristics or standards within the energy system. For example, recent legislation proposed in the U.S. Senate would require that all new automobiles manufactured within ten years would include technologies enabling use of high-alcohol fuel blends; this technology standard could enable phase in of more widespread bio-ethanol utilization [67]. In contrast, the 1995 prohibition of leaded gasoline in highway vehicles and the fuel oxygenate requirements for regions in non-compliance of National Ambient Air Quality standards for carbon monoxide under the Clean Air Act are examples of policies specifying fuel characteristics rather than particular technologies [68, 69]. It has been suggested that similar policies targeting diesel fuel sulfur content could support biomass

FT liquids production; however, such systems may not compete effectively with fossil FT systems, which can provide similar air quality benefits at potentially lower costs [28].

Finally, the Corporate Average Fuel Economy (CAFÉ) program represents an example of a performance standard. Note that each of these policy structures support a market for the targeted policy objective. The relative efficiency of such policies depends on how they are structured. In general, performance standards appear to be relatively efficient as they specify the objective (rather than the pathway) and let the market determine how it will be achieved.

Tax credit and incentive payment schemes, such as the U.S. Renewable Energy Production Incentive (“REPI”) and Renewable Energy Production Credit (“REPC”) programs discussed in Section 4.3.2., represent an alternate approach. Such policies explicitly define a value for targeted non-financial benefits and induce minimal direct risk for industry by rewarding participation without penalizing non-compliance. As direct subsidies, however, they create substantial costs to government resources, and therefore may be limited by overarching budgetary constraints. In this context, corporations may have difficulty justifying deployments based on incentives that are at risk from the government’s budgetary process. Efficient deployment under such frameworks may therefore be compromised by insufficient funding—absent inherently competitive markets for receiving policy-stated incentives. Moreover, the risks from insufficient funding suggest that participation rates will tend to under-represent the market supply curves for targeted policy objectives.

Another approach, for which there have been several proposals in the U.S. at both state and federal levels, is to create Renewable Energy Portfolio Standards (“REPS”), which define the minimum fraction of supply for specific products that must be derived from renewable resources [61]. While REPS is a common example, the concept of a portfolio standard can be generalized to target other policy objectives, as well. Portfolio standards may be more efficient than incentive payments or credit schemes, as the value for the targeted attribute (e.g., ‘renewability’) is defined in the context of a competitive market in which the policy-stated demand is matched against the market supply curve. Moreover, the costs for this policy structure are born directly by industry and consumers rather than the government, removing government budgetary constraints and reducing associated risks of participation. However, absent integration of means of flexibility—e.g., a backstop price for renewable energy credit purchasing from an associated regulatory agency—portfolio standards can create considerable risk for energy suppliers and consumers from unproven supply curves for the targeted benefits. This is similar to the notion of a “safety valve” discussed with respect to cap and trade policies.

Cap and trade policies are relatively well established in the U.S. energy sector as this framework is currently used to regulate emissions of sulfur and nitrogen oxides. In this framework, a market is created for the policy objective (e.g., emissions reductions) by the distribution of a limited number of permits or allowances for the associated activity (e.g., emissions)—where the quantity of allowances is determined by a policy-defined target. Allowances can then be traded in a relatively free market.

Challenges under cap-and-trade schemes typically arise in terms of defining meaningful and achievable targets for the controlled activity (e.g., emissions caps), allocating allowances, accounting for activities in the market, and banking of unused allowances. In addition, as with portfolio standards discussed above, cap-and-trade schemes can impose substantial risks on market participants from unproven mitigation supply curves absent some means of flexibility. The so called “safety valve”, e.g., a price at which additional allowances may be purchased from a regulatory agency, is an often cited example [4, 70]; however, emissions allowed through such a mechanism cannot be recovered suggesting that borrowing against future reductions may be a more appropriate approach in regulating emissions of persistent compounds [70]. With those caveats in mind, cap-and-trade frameworks are generally thought to support efficient mitigation, by allowing market participants to balance operating profits from emitting activities against market prices for emission allowances.

As discussed in Chapter 2, biomass cofire can provide emissions reductions in sulfur and nitrogen oxides, which are regulated in the U.S. under cap-and-trade policy frameworks. Emissions reductions from cofire do not appear cost-competitive in this context (other than niche applications where very high sulfur coal is displaced), and the scale of reductions appears insufficient to achieve the stated air quality objectives. As such, it appears unlikely that these particular policies will be capable of motivating substantial increases in bio-energy utilization (though they may open certain niches); however, the cap-and-trade policy framework could plausibly support bio-energy systems in another context, e.g., regulation of GHG emissions. Its relevance in this regard is further

evidenced by the Kyoto Protocol, which is structured as a type of high level cap-and-trade system, in which the cap is defined relative to 1990 emissions, and trade is facilitated by the so called Joint Implementation and Clean Development Mechanisms. Smaller scale cap-and-trade frameworks have also been developed in response to anthropogenic climate change, including, notably the European Union Emission Trading Scheme [71].

Activity-dependent tax schemes, such as GHG emissions taxes, could also support bio-energy development. Such taxes have been argued to be among the most efficient policy structures for mitigating carbon (or GHG) emissions [4], as they define an even price for emissions across the economy that can evolve over time with emissions and emissions targets. However, the economic implications of transitioning to such a system seem to depend on how tax rates are defined, managed, and communicated over time. Moreover, gaining industrial acceptance for such a scheme may represent a substantial barrier to policy enactment and enforcement.

Novel approaches to creating markets for non-financial policy objectives in the energy sector are also conceivable. In all cases, however, the level of biomass-based mitigation induced by market-based frameworks will depend on a variety of factors. For example, bio-energy development in response to climate-motivated policies will depend on the relative competitiveness of biomass-based strategies within the spectrum of available mitigation options, the scale of emissions reductions and effective shadow carbon prices induced by the policy, and the specific definitions adopted for carbon emissions in the

context of the biological carbon cycle.

4.3.2. Policy instruments: proposed or enacted by the U.S. Congress.

Mechanisms capable of supporting expanded utilization of bio-energy systems have been included within proposed bills and enacted laws in the U.S. at both federal and state levels. However, many of these mechanisms exclude—both explicitly and implicitly—certain biomass energy systems, particularly cofire of biomass residues with coal. Further, substantive inconsistencies exist across policy instruments that may yield inefficient deployment even if all potentially relevant technologies were included. The potential of relevant policy instruments to support biomass energy systems is discussed below. The focus of this discussion is primarily on the Energy Policy Act of 2005 (“EPAct 2005”); federal legislation that has been proposed or enacted is also summarized.

Energy Policy Act of 2005. EPAct 2005 was signed into law by President George W. Bush on August 8, 2005. This bill reauthorizes, revises, and expands upon many of the previously enacted policy instruments supporting renewable energy development, including the Renewable Energy Production Incentive (“REPI”) and Renewable Electricity Production Credit (“REPC”). Further, EPAct 2005 defines federal renewable energy purchase requirements and new funding mechanisms to support research, development, demonstration, and commercial application of renewable energy

technologies. While many of EPOA 2005's provisions represent important steps toward expanding bio-energy capacity and renewable energy more generally, key constraints within those provisions will likely limit EPOA 2005's effects on near-term bio-energy deployment.

REPI originally provided incentive payments of 1.5 c/kWh (1993 dollars with subsequent indexing for inflation) for electricity produced from renewable resources at facilities owned by public and certain other tax-exempt entities (qualified facilities). Authorization for REPI payments expired in 2003; however, Section 202 of EPOA 2005 reauthorizes REPI payments through 2026 and extends eligibility to all qualified facilities in operation before 2016. A potentially non-obvious consequence of this revision may be to support cofire retrofitting of older facilities, previously excluded through definition of a relatively narrow window of eligibility around the date of first operation for qualified facilities.

REPI payments continue, however, to be contingent on federal appropriations. Historic appropriations have systematically under-funded the REPI program, supporting less than 17% of qualified generation over the life of the program and less than 11% since the 2000 fiscal year ("FY2000") [72]. This issue has been addressed in EPOA2005 by specifying that if funds are insufficient to support all qualified generation, then appropriated funds shall be distributed according to a new two-tier system. 60% of appropriations will be allocated pro-rata to "first tier" facilities that utilize solar, wind, ocean, geothermal, and so called "closed loop" biomass (essentially defined as biomass from dedicated energy crops) and the remaining 40% will be divided among all other projects. Historically, over

96% of qualified generation has been from what are now defined as “second tier” facilities; applying the new two-tier system to generation and appropriations since FY2000 suggests average incentive payments to second tier facilities of roughly 0.1 c/kWh [72]. As most proximately available biomass is not from dedicated energy crops; this implies that near-term bio-energy projects will receive negligible support from the REPI framework—absent substantial appropriations increases.

REPC is analogous to REPI but for facilities owned by private, for-profit corporations. Such facilities are responsible for roughly 75% of coal-fired utility generation, underscoring the importance of their inclusion within coherent policy instruments [73]. REPC provides a 1.5 c/kWh tax credit (1993 dollars indexed for inflation) to facilities that produce and sell electricity from renewable resources for the first 10 years of operations—note that this is different from REPI payments, which are phased-out, based on the relation between renewable energy production costs and dominant market selling prices. Section 1301 of EPAct 2005 extends the date by which qualifying facilities must begin operations through January 1, 2008 and makes a variety of other amendments with minimal effect for bio-energy.

Like REPI, the REPC framework differentiates between so called “closed loop” and “open loop” biomass such that “closed loop” applies only to dedicated energy crops. Projects utilizing “open loop” biomass are eligible for tax credits at 50% of the normal REPC rate. However, projects *cofiring* “open loop” biomass with fossil fuels are specifically excluded from receiving any REPC credits.

Section 203 of EPOA 2005 establishes a federal purchase requirement for electricity from renewable resources ranging from 3% beginning in 2007 up to 7.5% after 2012. In contrast to the REPI and REPC programs, this section adopts an inclusive definition of renewable biomass resources, without restrictions against residues or waste streams. This is not surprising as including such restrictions would have increased implementation costs. The purchase requirements are weakened, however, by the qualification that the purchase requirements should only be met “to the extent [they are] economically feasible and technically practicable”, and by providing double credit for renewable electricity produced on federal property or “Indian land” and used by a federal facility [62]. Support for renewable energy from this section clearly hinges on the interpretation of these qualifications. However, even with aggressive implementation, the cumulative effect will be generally small as the federal government is responsible for only about 1.4% of domestic energy consumption [74]. In spite of the relatively small scale, federal purchase requirements may provide meaningful support for certain bio-energy and renewable energy projects and create opportunities for demonstration of renewable energy technologies.

Several sections of EPOA 2005 authorize additional funding that could be applied in part towards bio-energy development. Section 931 (“Renewable Energy”) authorizes between \$213 and \$274 million per year from 2007 through 2009 to support Bioenergy Program projects, up from \$90 million funded in 2005 [62][75]. Of that, between \$100 and \$150 million is earmarked for development of “integrated bio-refineries”, which are defined as

facilities capable of producing heat, power, biofuels and other biomass-based products (note that such facilities could include CCS). The same section also authorizes an unspecified level of support for research and development into co-utilization of renewable energy resources with each other and with fossil fuels. Section 971 (“Science”) authorizes an additional \$49 million annually from 2007 through 2009 to support “Integrated Bioenergy Research and Development”.

These funds are part of a broad expansion in authorized support for renewable energy research and development (and energy-related R&D, more generally) [76]. However, spending in these various programs, while authorized, remains dependent on annual appropriations, which may fall short of authorized levels. Moreover, they must support diverse research programs with multifaceted objectives and substantial flexibility in how appropriations are actually spent. As such, it is difficult to predict what, if any, support will be provided to expanding near-term bio-energy capacity under these various provisions. Moreover, while the research program and project-specific funding provided in these sections is important for advancing renewable energy development, it does not provide systematic incentives—as the REPI and REPC programs do—capable of stimulating broad expansion of renewable energy capacity.

Proposed bills. The 109th Congress has had a variety of bills introduced that could support biomass energy development. A total of 20 such bills were identified using Thomas, the information service provided by the Library of Congress [77]; however, many of these contain redundant provisions and few seem to have received significant

attention since variants on their key provisions were cannibalized by the inclusive H.R. #6, enacted as EPAct 2005 (which is discussed above and therefore not included in this discussion). However, they still provide some barometer for the scope of potential bio-energy support at the federal level.

Relevant provisions of these bills generally fall into four categories: (i) renewable energy production credits (“REPC”); (ii) renewable energy production incentive payments (“REPI”); (iii) renewable energy portfolio standards (“REPS”); and (iv) greenhouse gas controls (“GHGC”). Provisions in two bills do not fit into these categories: Senate bill #131, titled the “clear skies act of 2005”, links renewable energy to sulfur emissions controls; and House of Representatives bill #737, titled the “renewable energy and energy efficiency act of 2005” sets out broad objectives for biomass energy development without proposing specific policy mechanisms. Table 4.2 provides summary statistics of the bills considered here. Note that biomass residue cofiring is excluded in all provision categories except GHG. Figure 4.3 illustrates the potential effects of those proposed policies that are easily quantifiable by integrating the range of their proposed incentives with the supply curves for biomass residue cofire developed in Chapter 2. For the purpose of this illustration, it is assumed that proposed legislation is modified where necessary to include biomass residue cofire.

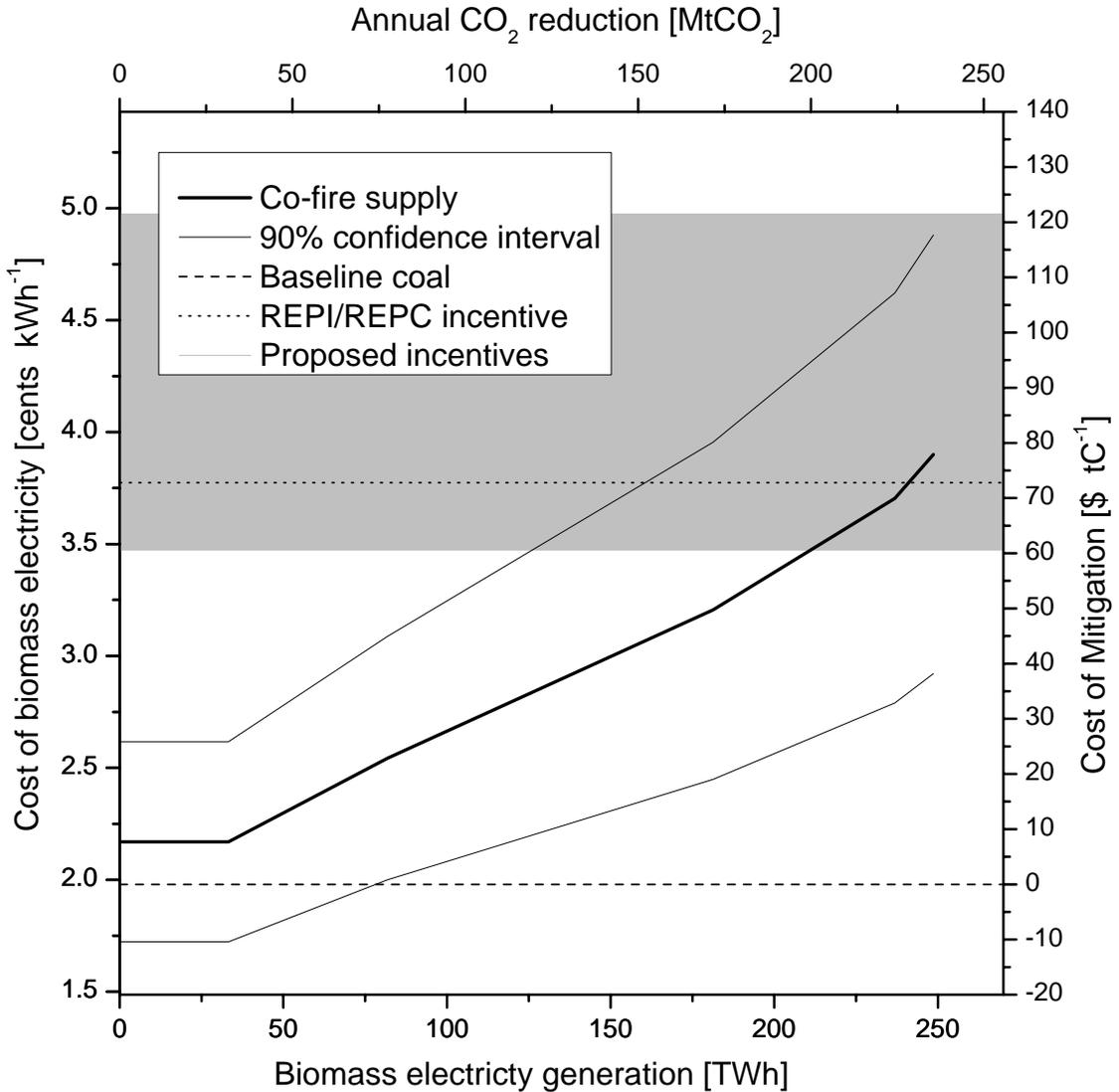


Figure 4.3. Proposed policy incentives and the cofire supply curve. The cofire supply curve is illustrated as in Figure 2.7 Panel b, assuming cofire of wood and agricultural residues and including cost adjustments for emissions of sulfur and nitrogen oxides. The supply curve is plotted both as a function of biomass electricity (TWh) and annual CO₂ reduction (MtCO₂). The baseline cost of electricity from pulverized coal is plotted at a value slightly below 2 cents per kWh and zero dollars per ton carbon mitigated. The range of proposed policy incentive values and the current value of incentives under the REPI and REPC frameworks are represented by adding their carbon price equivalents to the cost of electricity from coal. Therefore, the quantities of cofire associated with the intersections of these curves with the cofire supply curves represent estimates of what would be induced if biomass residue cofire qualified for these incentives.

Table 4.2.
Summary of proposed legislation supporting bio-energy

Program Type	Bills supporting renewable energy ^a	Bills differentiating residue cofire	Minimum Incentive [¢/kWh]	Maximum incentive [¢/kWh]
REPC	4	4	~1.8 ^b	1.9
REPI	4	3	1.5	~1.8 ^b
REPS	2	1 ^c	NA ^d	3 ^d
GHGC	8	0	NA	NA

^a Bills summarized in Table 4.2 include: for REPC, House bill 2828, and Senate bills 727, 1093, and 1229; for REPI, House bills 622 and 1127, and Senate bills 326 and 1093; for REPS, House bills 983 and 2828, and Senate bill 427; and for GHGC, House bills 610, 612, 1451, and 2828, and Senate bills 388, 397, 887, and 1203 from all bills recorded in the 109th Congress containing the keywords “renewable energy” on the Library of Congress legislative information service, Thomas, found at <http://thomas.loc.gov>. Note that relevant provisions in House bills 737 and 1873 do not fit into the above categories, and relevant provisions of House bill 6 (enacted as EPA2005) are not included. ^b This reflects the current value of the original 1.5 ¢/kWh incentive included in the REPI and REPC programs adjusted for inflation since 1993. ^c House bill 983 stipulates that renewable energy credits for cofire will only be granted for additional generation capacity provided by cofiring, not for fuel substitution; Senate bill 427 carries no similar limitation. ^d REPS provisions are market based and as such do not have minimum costs or incentive values, however, both bills do provide a maximum cost by mandating federal sale of renewable energy credits at the rate of 3 ¢/kWh.

4.4. Discussion

Bio-energy systems can advance a number of non-financial economic goods and policy objectives. However, the significant barriers to development indicate that policy support will generally be required for bio-energy systems to advance these objectives in the near term. A notable exception is that biofuels may become competitive, even absent favorable policy treatment if oil prices persist near recent highs. Policy support may be justified to the extent that contributions to targeted policy objectives from bio-energy are both meaningful and cost-effective. From this perspective, it appears that GHG mitigation provides the most rational basis for supporting bio-energy development (to the extent GHG mitigation is an important policy objective). In contrast, bio-energy's potential contributions toward air quality objectives do not appear to be generally cost-effective or of sufficient scale to warrant substantially increased policy support; and although the magnitude of energy security, rural and agricultural development, and sustainability benefits may be large, substantial further analysis is required to understand the value and economic efficiency of bio-energy's potential contributions in these dimensions before policy support can be fully rationalized.

Three general observations precipitate from this analysis (beyond support for further analysis into the relative economics of bio-energy's various potential contributions, as described above). First, consideration of CCS technologies could be specifically integrated within bio-energy technology development programs to support maximizing climate benefits from such technologies. Second, existing policy instruments could be

amended to provide consistent support for bio-energy systems that advance stated policy objectives. Third, new policy instruments could be developed that efficiently support non-financial benefits of bio-energy (and other advanced energy technologies) by defining even values for non-financial goods across the economy, such as through emissions taxes, cap and trade systems, or other similar means.

With regard to the first of these observations, the ability to incorporate CCS should be integrated as a research priority within government-funded bio-energy development programs. Biomass-CCS has the potential to significantly expand economically efficient opportunities for biomass-based carbon mitigation and reduce the total cost of mitigation, as discussed in Chapters 2 and 3 and in Section 4.1.1. These opportunities could yield three distinct benefits: cost-competitive mitigation in the very near term to achieve emissions pathways for long-term atmospheric GHG stabilization at desirable levels; emissions offsets to provide flexibility in transitioning to a GHG-neutral economy in the medium to long-term; and a means to actively manage atmospheric GHG concentrations in the very long-term. The later two of these benefits, in particular, may not be otherwise considered in near-term-focused commercialization efforts. Recognizing these potential benefits of biomass-CCS within the technology development process may push development efforts towards technologies that could more efficiently incorporate CCS, such as oxygen-blown biomass gasification.

In addition, existing policy instruments could be modified to support a more coherent set of technological alternatives. Several existing (and recently proposed) policies have the

potential to support substantial increases in bio-energy capacity, including specifically REPI and REPC. However, the definitions adopted within these particular programs are overly restrictive in terms of their distinction between “closed-loop” and “open-loop” biomass resources. Such a distinction is meaningful in the context of both climate change and renewable energy, as biomass energy is only carbon neutral and sustainable if the biomass is produced in a sustainable, “closed-loop”, manner. However, this does not imply purpose-grown energy crops, as specified in REPI and REPC—many residues are available from sustainable production systems developed primarily for other purposes. It is an advantage that biomass can be a feedstock for many processes other than energy production; utilizing residues from these processes for energy leverages the additional value added and effectively subsidizes bio-energy feedstock supply. This is directly analogous to the ability for marketable co-products to improve the economics of more conventional energy systems, including bio-energy systems using purpose-grown energy crops. By excluding biomass resources that are not purpose-grown for energy uses, these bills compromise both their efficacy in promoting renewable energy deployment and the efficiency with which they use appropriated tax revenue.

Replacement of harvested biomass is the central issue for bio-energy systems from both renewable energy and climate perspectives; the dominant driver for feedstock production is not. As such, residues from processes supplied by sustainable biomass production systems, in which harvested biomass is effectively replanted, should be classified as “closed-loop”. Consider mill residues as a representative example. The fact that a portion of harvested timber is used for lumber, paper, or other forest products is unrelated to the

sustainability of associated forestry practices. The fraction of timber embodied in mill residues can be considered carbon neutral, renewable, and “closed-loop” so long as the timber harvested is effectively replanted. Assuming carbon from the biomass used for lumber, paper, and other forest products is eventually returned to the atmosphere (e.g., through eventual recycling for energy purposes) and the timber is effectively replanted, then all of the biomass produced should be considered “closed-loop”—residues used for energy simply have a shorter recycle frequency. This argument holds generally for all biomass residues, regardless of the supply pathway.

With this argument in mind, both the REPI and REPC frameworks could be amended to include cofire of residues from sustainable biomass production systems within the definitions of “closed-loop biomass”. However, the cost of such an amendment in isolation is (very) likely prohibitive. As illustrated in Figure 4.3, the supply curve developed in Chapter 2 implies that the current, inflation-adjusted incentives of roughly 1.8 c/kWh could stimulate generation of nearly 240 TWh of biomass electricity from residue cofire annually. This represents a 67% increase in renewable generation, a 267% increase in non-hydro renewable generation, or roughly 6% of total electricity generated in 2004 [32]. This level of cofire would reduce annual coal utility emissions by over 200 MtCO₂ (~11%) at an effective cost of ~75 \$/tC (~20 \$/tCO₂). Supporting this level of generation would cost roughly \$4.3 billion annually. Assuming the cost is allocated to REPI in proportion to coal fired generating capacity owned by public or not-for-profit entities, this implies an annual cost to REPI of \$1.1 billion, up from \$3.7 million appropriated in 2003 and equivalent to ~5% of the U.S. Department of Energy’s

discretionary spending budget authority [35].

Alternatively, with the allocation assumption above, linear expansion of the supply curve in Figure 4.3 suggests that the REPI 2003 appropriation could have supported almost 4 TWh of biomass electricity from cofire with an incentive of 0.1 cents per kWh.

Assuming that qualified generation supported by 2003 REPI payments is proportional to the payments made (i.e., assuming an even incentive value is used in the calculation of figures for REPI incentives paid and unpaid for qualified generation presented in [72]), this represents 65 times more renewable electricity that was supported by REPI in 2003 [72]. Further assuming that cofire is similarly included under the REPC framework, this implies support for a total of roughly 16 TWh of biomass electricity from cofire, representing a 4% increase in renewable generation, a 18% increase in non-hydro renewable generation, or roughly 0.4% of total electricity generated in 2004 [32].

The implication of these estimates is that cofire of biomass residues is a substantially more efficient means for increasing renewable electricity generation than the technologies currently supported by REPI and REPC. To the extent these policies aim to advance sustainability and climate benefits, including cofire of biomass residues from sustainable production systems would notably increase their effectiveness and economic efficiency. To the extent these policies aim to support deployment of non-biomass renewable energy technologies, a more direct policy justified by projected economic benefits beyond those of bio-energy systems would be more appropriate. To the extent these policies aim to advance air quality benefits, a more efficient approach would be to

expand and enforce policies already in place for addressing these issues (e.g., the Clean Air Act).

Beyond modification of existing policy instruments, more flexible policy instruments could be developed that allow energy suppliers to optimize operations around specific policy objectives by setting an even value for non-financial benefits across the economy. For example, the most economically efficient methods for achieving carbon reductions are generally policies that set an even price on carbon emissions using either taxes or tradable permits [4]. Such mechanisms are particularly appropriate in the electric sector where successful trading systems for SO₂ and NO_x are already in place. Defining a renewable energy portfolio standard with tradable renewable production credits is a similarly efficient means of increasing utilization of renewable energy resources by letting the supply curve efficiently meet the policy-stated demand. However, to the extent climate benefits provide the dominant rationale for such policies, implementation of a broader framework to address GHG emissions more generally appears more appropriate. Regardless of the specific mechanism, it is likely that bio-energy systems—particularly biomass residue cofiring—would be among the first technologies to be widely implemented under an economically efficient policy framework targeting climate benefits due to the combination of low capital costs, low cost of electricity, and technological maturity.

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Chapter 4

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Chapter 5

Conclusions and policy recommendations

The aim of this thesis is to expand understanding of the scope of potential contributions from biomass in mitigating anthropogenic GHG emissions. Toward this end, Chapter 1 provides a general overview of biomass, industrial bio-energy systems, and the basic mechanisms by which they may contribute toward GHG emissions abatement. Chapters 2 and 3 provide assessments of a wide set of biomass-based mitigation strategies in terms of their underlying technologies and associated projections of their likely technical and economic performance. Chapter 4 discusses broader economic and policy issues affecting development and deployment. Through these analyses, several strategies have been identified as capable of potentially important contributions toward GHG mitigation. This concluding chapter attempts to integrate these results into a broader set of conclusions regarding potential contributions from industrial bio-energy systems and to develop a coherent set of policy recommendations. Conclusions are discussed in Section 5.1 and policy recommendations are discussed in Section 5.2.

5.1. Conclusions.

Industrial bio-energy systems are capable of advancing diverse policy objectives. While bio-energy may be competitive in certain market niches, widespread deployment will generally require support from public policy instruments that provide explicit value for

targeted policy objectives. In this context, mitigation of GHG emissions—the primary focus of this analysis—is judged to be of particular relevance due to the potential scale and relative economic efficiency of potential contributions from biomass (see Section 4.4). These contributions may be realized through diverse strategies that exploit synergies between biomass’s role in the natural carbon cycle and its potential roles in industrial energy systems. In particular, integrating CCS with biomass energy technologies can maximize leverage from biomass’s role in the natural carbon cycle for GHG mitigation and provide useful energy products (see Section 3.1). The merit of engaging such leverage will, however, depend on its relative economic performance in the context of other feasible strategies.

Niche applications exist in which biomass systems may be competitive with conventional energy systems in current and future energy markets. Cofire of very low cost biomass in existing coal-fired power plants and biofuel production (if oil prices remain high) are two examples specifically evaluated in this analysis (see Chapter 2 and Sections 3.4 and 4.3.2), though others exist. Deployment of such systems may be expanded to provide cost-effective mitigation as policies are developed that value GHG emission reductions.

For example, cofire of biomass residues in the U.S. could provide significant contributions in the very near term under policy scenarios valuing carbon emissions (see Figure 4.3). Cofire’s potential contribution in this regard results from a combination of low capital requirement, low cost of electricity, high technological maturity, and the ability to use currently available biomass feedstock. The modeling results in Chapter 2

indicate that such cofire could reduce U.S. carbon emissions by 100 to 225 MtC (367 to 825 MtCO₂) annually at mitigation costs of 30 to 70 \$/tC (8 to 19 \$/tCO₂) within as little as five years (see Figures 2.5 and 4.3). This combination of mitigation cost, scale, and time to deployment makes residue co-firing attractive relative to other proximate mitigation options. This is particularly relevant if moderate near-term reductions in GHG emissions are determined to be important for maintaining trajectories for long-term stabilization of atmospheric concentrations at desirable levels [1]. As discussed in Chapter 2, it is plausible that cofire could evolve to provide substantially greater mitigation in the longer term, though such scenarios should be viewed conservatively, due to their more speculative nature.

Alternatively, biofuels may become competitive with conventional petroleum-based liquid fuels in the near-to-medium term (e.g., within ~10 years) if oil prices persist near recent highs—or increase due to strong global economic growth (see Section 3.4 and Figure 3.9). (Note that current technologies using starch-based feedstock—particularly corn—are not as relevant from a climate perspective due to the energy intensity of agricultural inputs to production [2]; however, sugar-based processes—including, for example, those in Brazil that are competitive in current liquid fuels markets—should not be discounted.) Comprehensive cost and performance data are not widely available for advanced technologies—including ligno-cellulosic bio-ethanol production systems—that are nearest to commercial readiness, due to their proprietary nature. The limited information that is available suggests that some level of research and development is still required before deployment at commercial scale is possible [2-5]. However, integrating

results from several published engineering-economic analyses, as described in Chapter 3, suggests that certain biofuel production technologies may be cost-competitive with conventional liquid fuels without additional incentives if oil prices persist above ~50 \$/bbl (see figure 3.9). Policies motivated by climate, sustainability, energy security, rural and agricultural economic development, and air quality benefits of biofuels (including those already in place) should reduce both the oil price at which biofuels can compete and the time for deployment.

Within a similar time horizon (~10 years), biomass energy technologies with CCS may be viable, as discussed in Chapter 3. These technologies can generally compete only under policy frameworks that value climate benefits. Moreover, biomass-CCS strategies depend on the viability of CCS, which remains uncertain. That said, the general arguments presented in Chapters 1, 3, and 4 and the engineering-economic analyses in Chapter 3 suggest that biomass-CCS strategies are both technically viable and potentially important under policy scenarios targeting deep carbon emissions reductions.

The ability to generate negative net carbon emissions substantially increases the potential scope of biomass-based mitigation by providing a means to offset emissions across the economy. It increases the specific mitigation potential of biomass—measured in tons of carbon mitigated per ton biomass or equivalently per acre land in biomass production—increasing the mitigation efficiency of biomass resources (see Section 3.1). It may also yield cost-effective indirect mitigation—though emissions offsets—of emission sources that are expensive to mitigate directly (see Section 3.1 and 3.6). More generally, it provides

flexibility in the transition to a carbon-neutral economy, as mitigation of sources that are difficult to abate directly can be effectively offset until cost-effective direct mitigation options can be developed and deployed (see Sections 3.1, 3.6, and 4.1.1). Finally, the ability to generate negative emissions provides a mechanism for active management of atmospheric CO₂ concentrations over very long time horizons (see Section 4.1.1). This fundamentally changes both the range of emissions trajectories capable of stabilizing atmospheric CO₂ concentrations at desirable levels as well as the range of atmospheric concentrations that can be achieved, including, for example, pre-industrial levels (see Section 4.1.1).

Bio-energy systems are capable of produce multiple energy products across multiple markets; however, the limits imposed by biomass supply, as described in Section 4.2.1, imply that alternate bio-energy systems will have to compete for limited feedstock resources. If mitigating anthropogenic GHG emissions is the primary driver for bio-energy deployment, the economically efficient use of available biomass resources depends on petroleum prices and the value given to energy security benefits of biofuels. For example, if petroleum prices are low and energy security benefits of biofuels are not valued substantially, then electric-sector bio-energy systems without CCS appear to have the lowest mitigation costs relative to conventional pulverized coal generation (see Sections 3.3, 3.4, and 3.5). In spite of this, if fossil-CCS options are relatively cost competitive, then biomass-CCS will likely be able to enter an efficient market for low-carbon energy products at lower carbon prices than bio-energy systems without CCS (see Section 3.5 and Figure 3.12). The importance of mitigating electric sector emissions with

biomass would be substantially lower in such a scenario; however, biomass-CCS will likely become increasingly relevant as emissions targets demand mitigation beyond the large, stationary sources of the electric sector. In particular, indirect mitigation of transportation-sector emissions with offsets from electric-sector biomass-CCS deployments appears to be more cost competitive and more efficient—both economically and in terms of the mitigation potential of available biomass resources—than direct mitigation with biofuels or biofuels-CCS (see Figure 3.12 and Table 3.8).

In contrast, if petroleum prices are high or if energy security benefits of biofuels are valued substantially, then biofuels may become competitive (or nearly competitive) with conventional liquid fuels (see Figure 3.9). In which case, carbon mitigation could be achieved via fuel substitution at zero carbon price (or at relatively low carbon prices). In this scenario, additional mitigation could be achieved by integrating CCS with biofuel production (see Figure 3.9).

Importantly, large-scale deployment of industrial bio-energy systems also embodies certain risks. For example, financial costs may accrue from price effects on agricultural products (see Section 4.1.2); these price effects may yield human health and welfare costs from increasing food prices; and environmental costs may develop from increased soil erosion rates and ecosystem degradation (see Section 4.1.6). CCS embodies certain risks, regardless of its application in biomass or fossil fuel systems. Cost-benefit analysis, including those employing multi-attribute utility theory, cannot fully resolve trade-offs in these various risks and benefits, particularly in light of potentially disparate value

preferences across relevant geographic scales. Some level of bio-energy development is likely beneficial (see Section 4.1.6), and revealed social preferences may support increasing development over time (e.g., expanding fossil-CCS would lend support to biomass-CCS); however, ongoing analysis of the various potential costs, benefits, and trade-offs is crucial to enabling effective management of the consequences of bio-energy supply chains.

5.2. Policy recommendations

In general, policy instruments should be developed to create economically efficient incentive structures that support targeted policy objectives, including carbon mitigation, and research and development initiatives should be advanced to support a robust portfolio of technologies for achieving those policy objectives. Economically efficient policies are generally those that define economy-wide values or prices for marginal contributions to specified policy objectives [6]. Emissions taxes and cap-and-trade schemes are commonly cited examples in the context of the energy sector, the later of which has been successfully deployed in managing NO_x and sulfur emissions [7, 8]. Such policies should be specifically designed to support the full range of relevant technology solutions—including biomass-CCS.

Restrictions limiting credit for energy from cofire and biomass residues should be removed from the definitions of closed-loop biomass resources in the REPC and REPI

programs. Adoption of new definitions that include cofire of sustainably harvested biomass residues combined with re-valuation of the tax credits and incentive payments granted under these programs could substantially increase their efficacy and efficiency. The supply curves developed in Chapter 2 suggest that such modifications could stimulate approximately 16 TWh of renewable electricity annually with the 2003 program funding, a 65 fold increase from what was actually generated. This would increase the efficiency of federal funds spent in support of renewable energy generation from 16 kWh/\$ to 1 MWh/\$.

CCS technologies should be explicitly considered within bio-energy research and development programs. Integration of CCS, while non-obvious, could plausibly improve the economics of technologies already under consideration. For example, biofuels may be expected to become competitive from a combination oil price forecasts and energy security or climate motivated policies. However, the financial performance of these technologies may be improved considerably under a carbon constraint by integrating CCS. Explicit consideration of CCS technologies could plausibly tip incremental technology development decisions toward those that can more easily support future CCS integration. Proximate costs supporting biomass-CCS as a Real Option¹ could arguably be small with substantial dividends from simplified future retrofitting. Technologies and decisions that may be affected by such explicit consideration include:

- i. *Oxidizing agents in gasification.* Oxygen or steam-blown systems can avoid

¹ Real Option refers to the ability, without obligation, to undertake a particular decision. In this case, deploying technologies capable of facilitating future integration of CCS provides the ability to deploy biomass-CCS if and when that becomes desirable.

nitrogen dilution of the syngas inherent to air-blown technologies and are therefore preferred for CCS applications (see Chapter 3).

- ii. *Syngas cleaning systems.* Integration of CCS may affect the configuration of syngas cleaning systems. For example, the benefits of hot-gas cleaning may be reduced due to the low temperatures required for carbon capture (absent intermediate high-temperature reforming processes). In such a scenario, it is plausible that CCS technologies could be closely coupled with more mature low temperature syngas cleaning systems.
- iii. *Target syngas compositions.* Alternate gasification technologies and operating parameter settings may be favored in optimizations that value high CO₂ concentrations in raw syngas, which may reduce the importance of downstream gas-water shift and steam reforming processes.
- iv. *Bio-energy facility siting.* Proximity to existing or potential future CO₂ sequestration infrastructure could be explicitly considered in facility siting decisions—in addition to other siting considerations, such as proximity to biomass resources—to enhance biomass-CCS Real Options;
- v. *Facility configuration.* Retrofit requirements could be explicitly considered in bio-energy facility designs to simplify and reduce capital costs for future retrofits.

Biomass co-utilization should be explicitly considered within research and development programs advancing fossil-CCS technologies. The distributed nature of biomass resources combined with high costs for biomass transportation, as discussed in Chapters

2 and 4, imply that the most efficient use of many biomass resources may be in local fossil energy conversion facilities. While this is a general statement of the co-firing benefits for biomass utilization, fossil fuel facilities with CCS could also benefit. Specifically, captured biomass carbon could be applied to offset fossil carbon emissions from incomplete CO₂ capture, even with relatively modest biomass blend ratios. The result would be carbon neutral—or negative—energy products from (primarily) fossil fueled facilities.

The potential leverage from integrating CCS with bio-energy systems should be explicitly incorporated into analyses of GHG mitigation options, technology portfolios, and emissions trajectories. For example, emissions from liquid transportation fuels are often considered to be among the most difficult to mitigate, due to the combination of decentralized emissions sources, fuel transportation and distribution infrastructures, fleet turnover rates, and end user performance expectations. In this context, hydrogen is often presented as the dominant if not only solution for GHG-neutral transportation; however, the calculations presented in Table 4.1 indicate that between 44 and 168% of carbon emissions from liquid fuels in 2050 could be mitigated with biomass-CCS under the assumptions in the IPCC SRES scenarios [9]. This enables a significant departure from the emissions trajectories that are currently projected.

It does not follow that biomass-CCS should be construed as a “silver bullet” to mitigation in the transportation (or any other) sector. Rather, integration of CCS will substantially expand (i) the potential roles for biomass within a portfolio approach to GHG mitigation,

(ii) the suite of achievable emissions trajectories under scenarios including bio-energy systems, (iii) the suite of trajectories capable of stabilizing atmospheric GHG concentrations at desirable levels, and (iv) the range of stabilization concentrations that can be achieved. Incorporation of other negative emissions systems should have similar (or potentially greater) effects, but the relative certainty in the ability to generate negative emissions with biomass-CCS means that such capabilities can be incorporated into near term analyses of technology and policy options. This incorporation may substantially change the results of such analyses in terms of dominant approaches to GHG mitigation.

More systematic analysis should be conducted to quantify potential contributions from biomass technologies in advancing well-specified policy objectives and compare these contributions against those achievable with other means. Bio-energy systems have been promoted as means to address a wide variety of policy objectives (see Section 4.1).

However, strong policy recommendations can generally not be justified absent explicit characterization of the efficacy and efficiency with which the objectives can be advanced in both relative and absolute terms.

Finally, and most generally, to the extent that climate change is determined to be a social, economic, or environmental *bad*, policies to support economically efficient mitigation of GHG emissions and long-term transition to a GHG-neutral economy should be developed and implemented in a timely manner. Such policies should be designed to effectively set even prices, directly or indirectly, for GHG emissions across the economy and allow trading of emissions costs and credits to ensure efficient deployment of GHG-mitigating

strategies. Further, such policies should be structured to balance emissions reductions required to maintain trajectories for long-term stabilization of atmospheric GHG concentrations at desirable levels with the evolving costs of mitigation. In other words, the effective cost associated with GHG emissions should be designed to evolve with near and long-term mitigation objectives.

Within such a GHG management framework, deployment of biomass-based mitigation options can be expected to evolve without (potentially inefficient) incentives for particular biomass-based strategies. However, policy instruments motivated by other objectives that bio-energy systems can simultaneously advance will likely accelerate biomass deployment and shift the portfolio of biomass technology deployments to serve this broader set of policy objectives. For example, a bio-energy portfolio including liquid fuels, hydrogen, and electricity production may be shifted toward biofuels and hydrogen (in the longer term) by energy security motivated policies. Alternatively, such a portfolio may be shifted toward electricity and hydrogen (in the longer term) by climate-motivated policies. The implication of policies motivated by air quality, rural economic development, or sustainability depends on the specific implementation as alternate bio-energy systems can differentially advance multiple dimensions of these objectives.

Industrial bio-energy technologies are generally competitive only in niche applications; however, there are many niches in modern energy systems, and policies promoting GHG mitigation, energy security, air quality, rural economic development, or sustainability can be expected to substantially expand those in which bio-energy can compete. Moreover,

integration of CCS with bio-energy systems can expand both the role for biomass and the set of feasible emissions trajectories under scenarios with strong GHG emissions constraints.

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Chapter 5

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Appendix A

Cofire paper in *Environmental Science and Technology*

Assessment of Potential Carbon Dioxide Reductions Due to Biomass—Coal Cofiring in the United States

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Cofiring biomass with coal in existing power plants offers a relatively inexpensive and efficient option for increasing near-term biomass energy utilization. Potential benefits include reduced emissions of carbon dioxide, sulfur, and nitrogen oxides and development of biomass energy markets. To understand the economics of this strategy, we develop a model to calculate electricity and pollutant mitigation costs with explicit characterization of uncertainty in fuel and technology costs and variability in fuel properties. The model is first used to evaluate the plant-level economics of cofiring as a function of biomass cost. It is then integrated with state-specific coal consumption and biomass supply estimates to develop national supply curves for cofire electricity and carbon mitigation. A delivered cost of biomass below \$15 per ton is required for cofire to be competitive with existing coal-based generation. Except at low biomass prices (less than \$15 per ton), cofiring is unlikely to be competitive for NO_x or SO_x control, but it can provide comparatively inexpensive control of CO₂ emissions: we estimate that emissions reductions of 100 Mt-CO₂/year (a 5% reduction in electric-sector emissions) can be achieved at 25 ± 20 \$/tC. The 2–3 year time horizon for deployment—compared with 10–20 years for other CO₂ mitigation options—makes cofiring particularly attractive.

Introduction

The increased use of biomass energy has been variously proposed as a means to abate CO₂ emissions, to reduce our dependence on imported petroleum, to enhance rural development, to improve energy security, or more generally to advance sustainability by increasing the use of renewable resources. Biomass energy is the stored solar energy in unfossilized organic material such as energy crops or wood and agricultural residues. While biomass burning emits CO₂, use of biomass is considered carbon-neutral in the context of climate change if the fuel is sustainably harvested because the carbon in biomass is part of the active carbon cycle. Biomass currently supplies only about 3% of the U.S. primary energy but has the potential for meeting a significantly larger fraction of our energy needs (1, 2).

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Biomass is not economically competitive for electricity production in the current energy market except in niche applications where fuel costs are low or negative such as in integrated pulp and paper facilities. Biomass is generally more expensive than coal; the delivered cost of biomass typically ranges from \$1 to \$4 per GJ, whereas coal costs around \$1 per GJ. In addition, existing biomass power plants, which are based on well-proven, low-technology, direct-combustion steam generation, are inefficient, with typical overall plant conversion efficiencies ranging from 16 to 25% on a higher heating value (HHV) basis (3, 4) versus the 33–38% efficiency on a HHV basis of a typical coal-fired power plant (5). The lower conversion efficiencies of dedicated biomass power plants are due to the often high moisture content of biomass fuels, relatively small plant sizes, and lower steam temperatures. Much recent analysis of biomass energy has focused on the use of new technologies and purpose grown energy crops to produce electricity, hydrogen, or liquid fuels from biomass; while it is conceivable that such applications may eventually be important, their cost-effectiveness depends on dramatic improvements in the economics of biomass production and processing or dramatic changes in the economic value of the environmental, energy security, or rural-development attributes of biomass energy.

This paper analyzes cofiring of biomass fuels in existing coal-fired electric generating facilities using currently available agriculture and forest products residues. Cofiring replaces a fraction of the coal used in an existing power plant with biomass—typically 2–20% on an energy basis. Since power production from coal exceeds that from dedicated biomass facilities by almost 2 orders of magnitude (6), even relatively minor incorporation of biomass as a cofiring fuel will notably increase electricity production from biomass. Numerous commercial-scale demonstrations indicate that biomass—coal cofiring is technically feasible (7–18). By taking advantage of existing coal-fired power plants, cofiring can be implemented with low capital costs over a time frame of 1–2 years if sufficient biomass residues such as urban wood waste, mill, and agricultural residues are available. Cofiring uses biomass resources efficiently because large-scale coal-based power plants do not have the efficiency penalties associated with lower steam temperatures and small plant sizes of dedicated biomass systems, and cofiring has been shown to have minimal impact on the overall power plant conversion efficiency (7, 10–12, 18). Cofiring does not overcome the higher heating value efficiency penalty associated with fuel moisture, which is unavoidable unless the fuel is dried before firing. Cofiring can also address the often limited and cyclical nature of biomass fuel availability by appropriately adjusting the coal—biomass blend ratio.

Costs, however, are still a major barrier to increased biomass—coal cofiring. Cofiring significantly increases the efficiency of biomass utilization compared to existing dedicated biomass electricity production and does not have high capital costs and uncertainty of new advanced technologies. However, the high cost of biomass remains a problem; cofiring is only cost-competitive in niche applications where low-cost locally available biomass displaces high-cost coal (3, 8, 19, 20).

Cofiring offers the possibility to reduce the net CO₂ emissions on an electrical output basis, to generate green energy with existing infrastructure, to provide a useful service to local industries that generate biomass residue, and to achieve modest reductions in SO₂ and potentially NO_x

emissions. Therefore, policies that, for example, constrain carbon emissions or promote renewable energy may lead to more substantial levels of cofiring. A number of analyses have considered the effects of policies to promote renewable energy or to constrain carbon emissions on the economics of cofiring. Many of these only consider an individual plant and therefore provide little insight into national cofiring potential, which depends on both plant level economics and national fuel supply (3, 8, 19, 20). Estimates of nationwide cofiring potential span a wide range from a 1.1 TWh (21) to 88 TWh (22) of electricity from biomass in the year 2010 (0.4–40% of projected coal-based power generation). The lower estimate is based on existing energy markets and current policies; the upper estimate assumes a national policy to reduce carbon emissions and relatively inexpensive energy crops. The wide array of assumptions combined with the relative lack of cost information makes it difficult to compare the different estimates and to make comparisons with other technologies.

The goal of this paper is to evaluate the potential and costs of biomass–coal cofiring in the United States. Section 2 reviews the technical feasibility of cofiring. In Section 3, a plant-level economic model is developed to estimate the cost of producing electricity from biomass–coal cofiring, and in Section 4, this model is combined with state-by-state estimates of biomass availability (23) to develop a supply curve for biomass–coal cofiring for the United States. This analysis accounts for uncertainties in a wide range of parameters such as biomass fuel costs, fuel variability, and capital costs. Section 5 assesses the cost-effectiveness of cofiring as a means to reduce emissions of CO₂, SO_x, and NO_x and to increase renewable energy utilization when compared to alternative means to achieve these benefits.

Technical Feasibility

Over the past decade numerous demonstrations have been performed using commercial coal-fired utility boilers in both the United States and Europe to evaluate the technical feasibility of biomass–coal cofiring (7–18). These demonstrations provide a wealth of information that spans the range of major coal combustion technologies (stoker-, pulverized-, and cyclone-fired systems), important fuel types (wood, straw, switchgrass, and a variety of coals), feeding configurations (biomass premixed with coal and separate feed), and cofiring levels (1–40% biomass on an energy basis). The results indicate that there are no major technical obstacles to implementing cofiring: cofiring can either benefit or hinder power plant operations, but the problems appear manageable with judicious choices of fuels and operating conditions. Here we briefly review state-of-knowledge of the impacts of biomass–coal cofiring on power plant operations; for more information see recent reviews (7, 24, 25).

The impacts of cofiring on plant operations arise from differences in fuel properties between biomass and coal. Coal-fired power plants are designed to operate on a fuel with a given set of properties; fuel properties outside of the design range can adversely impact boiler performance. Jenkins et al. (26) compares biomass and coal properties; critical differences include the inorganic composition, the fibrous nature of biomass, moisture content, energy density, and volatile content.

Cofiring can create fuel-feeding challenges because coal processing and delivery systems are not designed to handle fibrous biomass fuels with their low energy density and high moisture content. For low levels of cofiring the biomass can often be premixed with the coal and delivered to the boiler using the existing coal feeding system (3, 7, 24). The exact level of cofiring that can be achieved by this approach depends on the excess feeding capacity at a particular power plant and is typically a few percent biomass by energy at full

load. Once this limit is reached, higher levels of cofiring cannot be achieved without reducing the capacity of the power plant (12). To achieve higher levels of cofiring a dedicated biomass preparation and feeding system is required; cofiring levels as high as 40% biomass by energy with no loss in capacity have been demonstrated using separate feeding systems (17).

Cofiring can reduce boiler efficiency and therefore overall plant fuel-to-electricity conversion efficiencies. Reported reductions are roughly a 0.5% loss in boiler efficiency for every 10% biomass input on a mass basis (7, 10, 11, 18). However, several studies report no change in boiler efficiency at low levels of cofiring (9, 12). The reductions in boiler efficiency while cofiring appears largely due to the often higher moisture levels of the biomass fuel compared to the coal and not due to a changes in boiler operations or the conversion efficiency of the coal. In fact, higher efficiencies have been reported for situations when cofiring a dry biomass with a wet coal (9, 10). The efficiency penalty associated with fuel moisture cannot be avoided unless the biomass fuel is dried before firing.

Unburned carbon is a concern when cofiring because biomass fuels cannot be economically processed to the same sizes as pulverized coal particles; for example, commercial-scale cofiring demonstrations typically prepare biomass fuels such that the particles pass through a 6.4 mm mesh—approximately 200 times larger than pulverized coal particles. Modeling and pilot-scale testing indicate that these large particles are unlikely to burnout completely in a utility boiler (27) but that the very high volatile matter content of biomass results in high conversion efficiencies for even large biomass particles. Many demonstrations report no significant increases in unburned carbon levels (7, 9, 10, 13, 28), and that reductions in boiler efficiency due to unburned carbon appear to be manageable with proper fuel preparation and firing conditions (18).

Ash deposition (slagging and fouling) frequently plays a dominant role in the operation of power generation systems that operate on coal, biomass, and other ash-forming fuels. Ash deposits form from fly ash, inorganic vapors, and some gas species that deposit or react on boiler surfaces through a variety of mechanisms. Commercial scale cofiring demonstrations indicate that cofiring coal with clean wood wastes does not create ash deposition problems (7); clean wood residues are excellent fuels with low ash and alkali levels (26). Agricultural residues such as straw and other herbaceous materials are important biomass resources that often have high alkali and chlorine levels creating deposition concerns; for example, straw-fired boilers often experience severe slagging, fouling, and corrosion problems (29, 30). Long-term commercial scale tests indicate that although coal-straw cofiring can cause some ash related problems including increased deposition and corrosion, the problems appeared to be manageable for up to a 20% straw share (by energy) (13, 15, 16, 28). Cofiring straw with coal may also reduce some of the problems associated with corrosion and deposition compared to combustion of straw alone (16, 31).

Cofiring reduces SO_x emissions because biomass fuels contain little or no sulfur (26); in fact, reductions in SO_x emissions are often greater than simple dilution because of reactions between the sulfur from the coal and alkali and alkaline species from the biomass which form sulfates that are collected in the particulate control system (14, 28). The majority of demonstrations report modest reductions in NO_x emissions (7, 11, 14, 17), but a few report no change (18, 28). It is generally believed that cofiring reduces NO_x, but the underlying mechanism is not completely understood. NO_x reductions due to cofiring are often attributed to the low fuel-nitrogen levels of biomass fuels and to changes of the stoichiometry in the near-burner region of the boiler caused

TABLE 1. Parameters Used in Cost Model^g

parameter	min	mode	max	ref
Economic				
utilization (%)		65		
interest rate (%)		10		
economic life (yrs)		10		
capital cost for cofeeding (\$/kW biomass) ^a	40	60	100	(3, 8)
capital cost for separate feed (\$/kW biomass) ^a	150	200	300	(3, 8)
nonfuel O&M for coal (c/kWhe)		0.4		(5)
biomass nonfuel O&M multiplier ^b	1.05	variable	1.15	(3, 8)
sulfur emissions cost (\$/tSO ₂)		175		
NO _x emissions cost (\$/tNO _x)	750	1500	3000	
Biomass				
oxygen content (wt %, dry)		41		(36)
carbon content (wt %, dry)		48		(36)
hydrogen content (wt %, dry)	5.4	6	7.3	(36)
sulfur content (wt %, dry)	0.02	0.07	0.15	(36)
moisture content (wt %)	10	30	50	(36)
heating value (HHV, MJ/kg, dry)	16.7	19.3	20.9	(36)
Coal				
plant efficiency (net, HHV, %)		34		(5)
cost (\$/GJ)		1.15		(39)
heating value (HHV, MJ/kg, dry)		23.5		(39)
sulfur content (wt %, dry)	0.5	0.9	3	(39)
NO _x emissions rate (lbs NO _x /MBTU _{th}) ^c	0.15		0.42	(35)
National Supply Curves				
coal cost, sulfur, carbon, and heating value		state specific		(39)
urban waste HHV (MJ/kg, dry basis) ^d		19.9		(36)
mill waste HHV (MJ/kg, dry basis) ^d		19.2		(36)
forest residue HHV (MJ/kg, dry basis) ^d		19.6		(36)
agricultural residue HHV (MJ/kg, dry basis) ^d		17.7		(36)
biomass cost ^e	-50%	variable	50%	(23)
capital cost for cofire (\$/kW biomass) ^f	variable	variable	300	(3, 8)

^aModel assumes that biomass can be cofed with coal at cofiring rates lower than 2% biomass on an energy basis. Higher biomass cofiring require a separate feed. ^b The factor by which nonfuel O&M costs for biomass exceed those for coal. The mode of the premium multiplier varies linearly with biomass thermal input between the minimum and maximum values, which correspond to a 2% and 20% cofiring rate, respectively. ^c No mode value given because a uniform probability distribution was used. ^d Averages of a large number of samples reported in EPRI biomass fuels database (36). ^e The modal values are taken from state-specific biomass supply curves developed by Walsh et al. (23). The min/max values are ±50% of the mode. ^f The modal value is linearly dependent on the state-specific cofire rate, eq 4, across the range of \$50/kW to \$150/kW. The minimum value is linearly dependent on the state-specific cofire rate across the range of \$60/kW to \$200/kW. ^g Except as noted, the columns min, mode, and max define a triangular distribution used for the Monte Carlo simulations. Parameters for which only a mode value is listed are treated deterministically by the model.

by the rapid release of the large volatile content of the biomass fuel. A critical issue is how the biomass and coal are introduced into the boiler (32, 33); for example, use of biomass as a reburn fuel can reduce NO_x emissions by 60% or more (33). Reburning is a combustion modification that reduces NO_x by injecting a fuel such as biomass downstream of the primary coal combustion zone (33). The reburn fuel (biomass in the case of cofiring) acts as a reducing agent for the NO_x formed in the primary combustion zone.

Cofiring biomass with coal may impact a power plant's ability to sell fly ash for concrete manufacture. The current ASTM standard (ASTM C 618) specifies that only coal ash meeting certain composition specifications can be used cement manufacture. However, there is no technical basis for limiting fly ash reuse to only coal ash; fly ash from cofiring is suitable for cement manufacture as long as it meets the necessary composition specifications. Efforts are underway to make the ASTM standard more technically based which will allow suitable fly ash from coal-biomass cofiring to be used in cement manufacture.

Plant-Level Economics

The economics of cofiring depend largely on biomass fuel costs, which vary from near zero or even negative cost for biomass waste streams, to projections above 100 dollars per ton (\$/t) for dedicated energy crops. We describe a simple model of the economics of cofiring that predicts electricity and pollutant mitigation costs and explicitly accounts for

uncertainty and variability in a wide range of parameters such as fuel costs, fuel properties, and capital costs. In the following section the model is combined with national biomass availability and coal consumption data to assess nationwide economics of pollutant mitigation using cofiring.

The cost of electricity (COE) is calculated as the energy-weighted average of the costs of electricity from biomass and from coal

$$COE(f) = f(C_B + VOM_B + F_B/\eta_B) + (1 - f)(VOM_C + F_C/\eta_C) \quad (1)$$

where *f* is the fraction of electricity output from biomass and the subscripts "B" and "C" refer to biomass and coal, respectively. The model considers three cost components, each evaluated on a per unit electricity output basis: *C* is the capital charge; *VOM* is nonfuel variable operations and maintenance costs; and *F/η* is the fuel cost (*F* is cost of fuel in energy units and *η* is the net plant conversion efficiency). As indicated by the subscripts, different values for these parameters are used for coal and biomass. Although cofire fraction is often defined on an energy input basis, we compute costs using the biomass cofire fraction, *f*, on an electricity output basis to avoid the confounding effects of differential fuel conversion efficiencies on mitigation cost calculations.

Table 1 summarizes the input parameters used for the calculations. The baseline coal-fired power plant is assumed

to have no outstanding capital costs. The model defines two levels of capital costs for cofiring biomass depending on the cofire rate (Table 1). The model assumes that low levels of cofire (up to 2% biomass by energy) can be achieved by cofeeding the biomass through the existing coal handling system; higher levels of cofire (greater than 2% biomass by energy) require a separate feeding system.

Nonfuel operation and maintenance (O&M) costs for coal combustion (Table 1) are based on U.S. averages (5). The fixed costs are incorporated into the calculations by assuming an annual plant utilization of 0.65, approximately the national average for coal-fired power plants (5). The specific O&M costs for biomass (VOM_B) are somewhat higher than those for coal (3, 8) and are estimated by adding a premium to coal O&M on a thermal energy basis. This premium ranges between 5% and 15% of the coal nonfuel O&M depending on cofire rate, with higher premiums associated with higher cofire rates (Table 1).

The model defines different net (fuel-to-electricity) conversion efficiencies for coal and biomass in order to accurately account for the impact of cofiring on power plant operations. We assume that the net conversion efficiency of coal to electricity is constant at 34% (HHV), which is the average value for plants built after 1950 (5). To estimate the conversion efficiency of the biomass to electricity, we calculate a higher heating value efficiency penalty due to the moisture content of the biomass fuel using the ASME Heat Loss method for calculating boiler efficiencies (34). This penalty is unavoidable unless the fuel is dried before firing. The method requires coal and biomass composition data; we also assume 20% excess air, 150 °C exhaust temperature, 1.5% losses due to unburned combustibles for both the biomass and the coal, and 1.5% minor losses (e.g., moisture in air) which are typical values for these parameters. This approach predicts the reductions in boiler efficiency observed in commercial cofiring demonstrations within $\pm 0.5\%$ (9–11, 18). The efficiency penalty due to fuel moisture is substantial for fuels with high moisture content; for example, the conversion efficiency of biomass that contains 50% moisture by mass to electricity is roughly 30% (HHV) versus the 34% (HHV) for coal. Note that even with the efficiency penalty due to high moisture content the overall conversion efficiency of biomass to electricity when cofiring is still significantly higher than the 16–25% efficiency (HHV) of existing dedicated biomass power plants (3, 4). The model does not account for changes in net plant efficiency due to changes in parasitic load when cofiring, which are expected to be small.

Biomass cofiring yields joint reductions in CO_2 , SO_x , and NO_x emissions. Cofiring reduces SO_x emissions because of the lower sulfur levels in biomass compared to coal. If FS is the fuel energy specific sulfur content (e.g., kgS/GJ), then the emissions per unit output, $ES(f)$, is computed as follows.

$$ES(f) = f \frac{FS_B}{\eta_B} + (1 - f) \frac{FS_C}{\eta_C} \quad (2)$$

Reductions in SO_x emissions are based on coal and biomass sulfur content distributions that are representative of the U.S. supply (Table 1). We do not account for any reductions beyond dilution.

The CO_2 emissions per unit electrical output, $EC(f)$, are computed using an identical formula to eq 2 except that the energy specific sulfur content (FS) is replaced with the energy specific carbon content. Displacement of coal with biomass results in a net reduction in carbon emissions from a climate change perspective because biomass carbon is in the active carbon cycle and therefore does not accumulate in the atmosphere if the biomass is used sustainably. Reductions in CO_2 emissions are based on the U.S. average coal carbon content and assume the carbon content for biomass is zero.

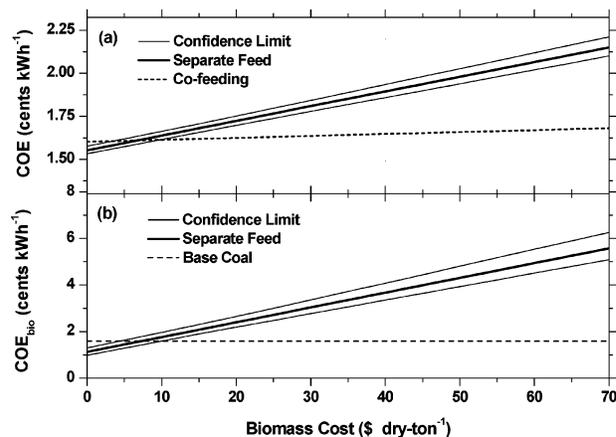


FIGURE 1. Cost of electricity as a function of biomass price: (a) overall plant level cost (coal and biomass) and (b) net cost of electricity from biomass, which equals $C_B + VOM_B + F/\eta_B$ from eq 1. The separate and cofeeding curves correspond to cofiring rates of 15% and 2%, respectively. The calculations are based on the U.S.-average coal and power plant characteristics defined by the mode values listed under the subheading “coal” in Table 1. The 5% and 95% confidence limits are shown for the separate feed case and are from Monte Carlo simulation using the distributions for capital costs, O&M costs, and biomass fuel properties listed in Table 1. The cost of electricity from the base coal plant is 1.6 cents/kWh.

In practice, fossil energy resources equivalent to less than 5% of the energy content of the biomass are typically consumed in its cultivation and processing (3).

The effects of cofiring on NO_x emissions are much more difficult to specify than its effects on SO_x or CO_2 emissions because of the complexity of NO_x formation in coal boilers. A large number of demonstrations report modest NO_x reductions when cofiring (7, 11, 14, 17); for this analysis NO_x emissions per unit electrical output, $EN(f)$, are computed assuming a linear reduction in NO_x emissions with biomass energy input. This level of reduction is consistent with the findings of many cofiring demonstrations (7). A wide range is used for the baseline coal plant NO_x emission rate to account for variability in NO_x reductions when cofiring (Table 1). This range, 0.15–0.42 lbs NO_x /MBTU_{th}, spans the emission rate from a low- NO_x boiler to the current U.S.-fleet-average boiler (35).

The cost of mitigating emissions is computed by dividing the change in cost of electricity by the change in emission rates. For SO_x , the cost of mitigation (COM) is

$$COM = \frac{COE(f) - COE(0)}{ES(0) - ES(f)} \quad (3)$$

Similar equations are used to calculate the cost of mitigation of CO_2 and NO_x emissions.

Figures 1 and 2 present the costs of electricity and pollutant mitigation from cofiring as a function of biomass price. Figure 1a shows the overall cost of electricity produced; Figure 1b shows the cost of the electricity produced from biomass, which equals $C_B + VOM_B + F/\eta_B$ from eq 1. The curves in Figures 1 and 2 are based on a typical U.S. coal-fired power plant burning average U.S. coal, as specified by the mode values listed under the subheading “coal” in Table 1. The confidence limits (5% and 95%) are from Monte Carlo simulation using the distributions for capital costs, O&M costs, and biomass fuel properties listed in Table 1. The distributions reflect the range of possible values for each parameter. For example, the distributions of biomass properties listed in Table 1 are calculated from the analyses of almost 300 different wood and agricultural residues samples

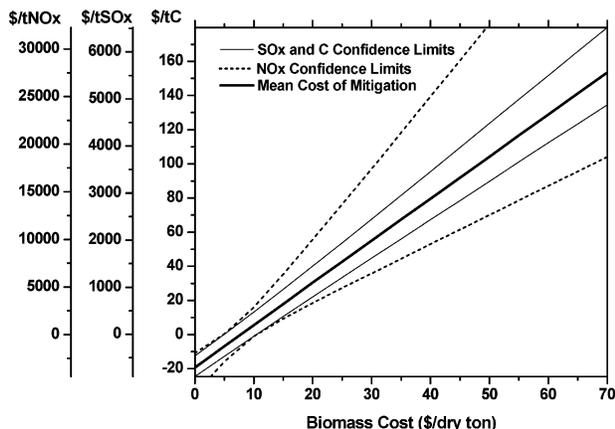


FIGURE 2. Cost of mitigation of carbon, sulfur dioxide, and oxides of nitrogen as a function of biomass price assuming cofiring using a separate feeding system and a cofiring rate of 15%. The curves are based on U.S.-average coal and power plant characteristics defined by the mode values listed under the subheading “coal” in Table 1. The 5% and 95% confidence limits are from Monte Carlo simulation using the distributions for capital costs, O&M costs, and biomass fuel properties listed in Table 1.

(36). The distributions in capital costs for cofiring reflect the range of reported costs in the literature.

The calculations of electricity and mitigation costs as a function of biomass price illustrate several important points. First, the variation in these costs across the range of reasonable biomass costs (0–70 \$/t) is much greater than the range between the confidence limits, which underscores the critical importance of biomass fuel cost in cofiring economics. Second, biomass must be available at low cost for cofiring to produce electricity at the same price as the base coal plant. Figure 1b indicates that the cost of electricity from biomass is comparable to that from coal at a biomass price of around 7 \$/t; the cost of biomass must be lower than this breakeven price in order for cofiring to produce electricity at a cost lower than a typical coal plant burning average U.S. coal.

The curves in Figures 1 and 2 do not account for any economic benefit for reductions in SO₂ and NO_x emissions due to cofiring. Including these credits by adding, for example, the cost of sulfur permits to the cost of electricity, COE, such that COE becomes COE + ES × Permit_Price, improves the economics of cofiring. A similar correction can be made for NO_x. Accounting for these credits can change the breakeven price for biomass can be as high as 20 \$/t depending on the power plant sulfur and NO_x emissions and the price of emission credits.

Pollutant mitigation costs as a function of biomass price are shown in Figure 2. Although cofiring reduces SO₂ and NO_x emissions, these reductions are not cost competitive with existing technologies except at low biomass prices. (Since the markets for these pollutants are reasonably well developed, permit prices are a plausible measure of the marginal cost of emissions control.) Figure 2 indicates that biomass must be available at a price of roughly 10 \$/t for cofiring to provide reductions in SO₂ that are comparable to the current market price of roughly 175 \$/tSO₂ for emissions credits. This value, 10 \$/t, can also be viewed as the breakeven price at which biomass must be available in order for cofiring to produce electricity at the same cost as a typical coal power plant burning average U.S. coal and paying a price of 175 \$/tSO₂ for sulfur emissions. For the case of NO_x emissions, biomass must be available at a price of 12–17 \$/t to provide NO_x reductions that are comparable to the current market price for emissions credits of 2000–4000 \$/tNO₂. In addition, cofiring at the modest levels considered here will likely only

result in modest NO_x and SO_x emissions, which will likely not be large enough to avoid using other control strategies to meet recently required reductions in NO_x emissions (37) or the SO_x emission constraints imposed by Title IV of the Clean Air Act Amendments of 1990.

Figure 2 shows that cofiring can reduce carbon emissions by displacing coal for prices between –20 and 150 \$/tC depending on the cost of biomass. While the cost of controlling CO₂ emissions is more uncertain than for criteria pollutants (because there is far less real-world experience), the cost of mitigating carbon emissions by cofiring are comparable with other technologies for abating CO₂ emissions from electricity generation and is discussed in detail in the section Policy Implications and Discussion.

The analysis shown in Figures 1 and 2 is based on an U.S.-average power plant burning U.S.-average coal in order to emphasize that the cost of cofiring in a specific plant operating with known coal quality is relatively certain, the confidence intervals are narrow, at a given cost of biomass. Varying coal properties such as coal cost, heating value, or sulfur content can alter the plant level economics by shifting the curves shown in Figures 1 and 2 and by changing the breakeven price for biomass to make cofiring cost competitive with the coal. This breakeven price is most sensitive to coal cost—plants burning higher priced coal have a higher price breakeven price for biomass. Coal sulfur has a more modest influence on the breakeven point. The economics of cofiring are most attractive for a power plant with high NO_x emissions operating on high cost, high sulfur coal—in this scenario the breakeven price of biomass approaches 20 \$/t versus the 7 \$/t for the average plant burning average coal shown in Figure 1. Alternatively, cofiring in a plant with inexpensive, low sulfur coal will result in a breakeven price much less than 7 \$/ton. Other studies have examined in more detail the different combination of factors that influence the economics of cofiring at the plant level (3, 8, 19, 20). In our calculation of the national supply curves, we account for the effects of variations in coal cost and coal quality on cofiring economics by using state-level averages for these parameters.

The range of breakeven prices for biomass discussed here (7–20 \$/t) are consistent with previously published plant level economic analyses (3, 8, 19, 20). The cost of biomass in existing markets or the expected price of energy crops provides a useful benchmark for evaluating the cost curves shown in Figures 1 and 2. For example, California produces a relatively large amount of biomass electricity and therefore has a reasonably well developed fuel market. During the 1990s biomass prices in California ranged between 35 and 55 \$/t (38) much higher than the breakeven price for cofiring, which underscores the fact that cofiring is not generally cost competitive in existing energy markets.

National-Scale Economics

National supply curves for electricity generation and carbon mitigation are estimated by combining the cofiring cost model with biomass fuel availability and electric sector coal consumption data at the state level and then aggregating the results at the national level. This approach uses state-level averages to account for the effects of variations in parameters such as coal cost and coal quality on national cofiring economics.

Walsh et al. (23) provides state-specific biomass fuel supply curves at delivered costs of 20–50 \$/t for several classes of materials including forest residues, mill residues, agricultural residues, and urban wood wastes. The cost estimates behind these supply curves include harvest, collection, and transportation to the power plant and account for a reasonable profit margin for suppliers. Transportation costs assume a haul distance of 50 miles to the power plant. For this analysis we only consider the cofiring potential using wood and

agricultural residue data reported by Walsh et al. (23). Cofiring with wood is a natural first step toward implementing cofiring because it poses few technical challenges; agricultural residues are considered separately because they pose more significant technical challenges than wood but represent a significant fraction of the available biomass fuel. We do not consider the potential of cofiring with energy crops because their near-term economic viability is not clear.

State-average cofire rates on an electricity output basis are defined as a function of biomass price

$$f(F_B) = \frac{E_B(F_B)/\eta_B}{E_C/\eta_C} \quad (4)$$

where $f(F_B)$ is the state specific cofire rate at biomass price " F_B "; $E_B(F_B)$ is the biomass energy (HHV) available within the state at biomass fuel price " F_B "; and E_C is the coal energy (HHV) consumed for power generation within the state (using year 2000 data). The biomass energy available in each state is calculated from the supply curves from Walsh et al. (23) and the higher heating values listed in Table 1. State-level coal consumption data are reported by the Department of Energy (39). Net coal-to-electricity conversion efficiencies (η_C) are assumed to be 34% HHV in all states. State-average biomass-to-electricity conversion efficiencies, η_B , are estimated by calculating a biomass fuel moisture efficiency penalty as described above using state-average coal property data (39) and the biomass fuel property distributions listed in Table 1. State-average cofire rates are limited to a maximum of 20%, which results in relatively low biomass prices in states with excess supply and limits the national cofire rate as regional imbalances in biomass supply and coal capacity result in stranded biomass resources. National-average cofire rates are estimated at each biomass fuel price as the average of the state-average rates weighted by the fraction of national coal consumption within each state.

State-average electricity and mitigation costs are computed for each price in the biomass supply curves using eqs 1–3 with the state-average cofire rates, conversion efficiencies, and coal properties. National-average electricity and mitigation costs are calculated for each price in the biomass supply curves as the average of the state-average costs weighted by the fraction of national cofiring within each state. For example, the national average cost of biomass electricity is

$$COE_B(F_B) = \sum \frac{COE_{B,i}(F_B) \times f_i(F_B) \times E_{C,i}}{f_N(F_B) \times E_{C,N}} \quad (5)$$

where $COE_B(F_B)$ is the national-average cost of biomass electricity from cofire at biomass cost " F_B "; $f_i(F_B)$ and $f_N(F_B)$ are the i th state-average and national cofire rate at biomass cost " F_B ", respectively; and $E_{C,i}$ and $E_{C,N}$ are the i th state and national coal consumption for power production, respectively. Monte Carlo simulation is used to evaluate the 90% confidence intervals of national-average electricity and mitigation costs for each biomass price in the biomass supply curves given uncertainty in fuel costs, capital costs, and O&M costs and the variability of biomass fuel properties represented by the distribution parameters in Table 1.

As illustrated by the results in Figure 1, fuel cost is a critical parameter for determining cofiring costs. A large uncertainty, $\pm 50\%$, is assigned to the biomass prices because the absence of widespread biofuel markets makes estimates of biomass cost and availability, such as those by Walsh et al. (23), highly uncertain. The systematic methodology of the survey provides a level of consistency in the estimates but leads to a correlated price uncertainty across states (i.e. if the cost estimates for a specific resource subcategory are underestimated, then

the fuel costs in all states will likely be higher than expected). In addition, biomass fuel prices are likely to be highly variable, dominated by local market conditions, as high transportation costs will require a substantial price differential to induce trade between local or regional markets.

The supply curves of Walsh et al. (23) were compared to other published fuel surveys (19, 40–42) as a consistency check; however, such comparisons are difficult because many surveys report national estimates without spatial resolution and residue availability for a specific region and/or do not provide any cost information. The survey by Walsh et al. (23) is unique in that it provides biomass supply curves at the state level. In general, comparisons among different surveys indicates broad consistency in the estimates of the total available resources indicating that amount of available biomass residues estimated by Walsh et al. (23) is reasonable. There is inconsistency in the estimates of delivered costs among the surveys, with the costs from Walsh et al. (23) being generally higher and therefore more conservative. Reference lists were compared to ensure that the different surveys were based on different primary sources.

The spatial distribution of biomass resources is a critical issue for this analysis because transportation costs limit the range over which biomass resources can be economically utilized (43). A state-level analysis cannot account for problems created by the distribution of biomass residues and coal consumption within each state. Ideally, one would use surveys of residue availability around each power plant (43); however, data are not currently available for such a nationwide analysis of cofiring potential. Transportation costs for biomass range from 5 to 10 \$/t per 50 miles (23, 43). The survey by Walsh et al. (23) includes the cost of transportation up to 50 miles, the large uncertainty assigned to biomass price will likely account for any additional transportation costs.

Several interesting trends are apparent when comparing the state-level biomass residue and coal consumption data shown in Figure 3. Major coal consuming states fall into three general categories: states with substantial wood residues, states with substantial agricultural residues, and states with little biomass residues. The Southeast falls in the first category with substantial coal consumption and large amounts of wood residues. Midwestern states, such as Illinois, Indiana, and Ohio, have little wood residues but large amounts of agricultural residues. The final category include states such as Kentucky, West Virginia, and Pennsylvania which have high coal consumption but relatively little biomass residues available for cofiring. Although there are significant biomass residues located in the western United States, this material cannot be used for cofiring due to the lack of coal-fired power plants in the region and the prohibitively high cost of transporting biomass.

National supply curves for biomass electricity and carbon mitigation from cofiring are shown in Figure 4. Results are shown for two scenarios: one that considers only wood residues (urban waste wood, mill waste, and forestry residues) and a second that considers both wood and agricultural residues. Figure 4a shows costs without accounting for credit from cofire NO_x and SO_x emissions reductions; Figure 4b includes this accounting by adding, for example, the cost of sulfur permits to the cost of electricity, COE , such that COE becomes $COE + ES \times Permit_Price$. A similar correction is made for NO_x . A large range of conservative values is used for NO_x permit price and baseline (Table 1).

The results indicate that cofiring can substantially increase our supply of biomass electricity at a reasonable cost; for example, the mean estimate of the Monte Carlo simulation is that cofiring wood residues could supply 15 TWh annual of electricity at a cost of 4 cents/kWh, which increases to almost 25 TWh (0.7% of current electric generation) if

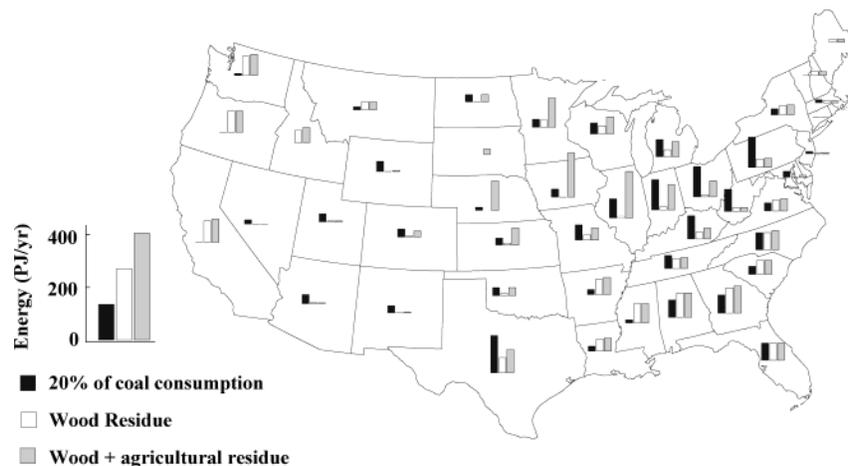


FIGURE 3. State-level coal consumption and biomass availability data. The height of the black bars indicates 20% of coal consumption; the height of the white bars indicate available wood residue at \$40/t; and the height of the gray bars indicate wood and agricultural residues available at \$40/t. All quantities are on an energy basis. Comparing the height of the bars within a state indicates the availability of biomass residues for cofiring. For example, if the white or gray bars are the same height as the black bar, then there is sufficient residues within that state to displace 20% of the coal on an energy input basis; if the white or gray bars are less than the black bar, then there is inadequate biomass residues to cofire at a level of 20%; if the height of the white or gray bars is greater than the black bar, then there are more than enough residues available to cofire at a level of 20%. Comparing the heights of white and gray bars provides an indication of the relative amounts of wood versus agricultural residues within a state. Coal consumption data are from ref 39; biomass data are from ref 23.

agricultural residues are included in the analysis. Including the value of NO_x and SO_x credits in the calculation (Figure 4b) reduces the carbon mitigation cost by roughly 10 \$/tC but has minimal effect on the relative cost of biomass electricity. Cofiring appears to be a cost-effective technology for providing modest reductions in carbon emissions from coal-fired power plants; for example, a 5% reduction in national coal-fired power plant CO_2 emission, ~100 million metric tons of CO_2 (Mt CO_2), could be achieved at a cost of less than 30 \$/tC (Figure 4b).

Only limited comparisons can be made between our assessment and previous analyses of national cofiring potential because of the relative lack of cost information provided by the previous analyses. The predictions shown in Figure 4a are very close to an EPRI estimate that 2.3% of coal generated electricity could be offset at a net cost of 22.60 \$/tC (20). The DOE predicts that a renewable portfolio standard requiring 10% of electricity production from renewable sources would result in almost 10 TWh of electricity generated annually by cofiring (44). No cost information is provided by the DOE analysis so it is difficult to compare results. Figure 4 indicates that this level of cofiring is feasible using available wood residues at a relatively low cost of approximately 2.7 cents/kWh for the electricity from biomass and that higher levels of cofiring are feasible at a reasonable cost compared to other renewables suggesting that the DOE analysis likely underestimates the potential for cofiring. The DOE analysis caps cofiring at 5% biomass share by energy at an individual coal-fired power plant and at a level of 4% of coal consumption on a national basis, which, as previously discussed, appear to be unnecessarily restrictive constraints. Conversely, our estimates of cofiring potential are substantially less than those of a DOE working group that consider the potential of cofiring under conditions of carbon constraints (22). They estimate that cofiring could generate 58–88 TWh of electricity in 2010 with dedicated energy crops produced at \$32/t providing a substantial fraction of the biomass feedstock. These costs may be optimistic given current projections of energy crop production costs; Walsh et al. (23) predicts that switchgrass becomes economically viable at a price of 40 \$/t with substantial production only feasible at prices around 55 \$/t (45).

Policy Implications and Discussion

Although biomass–coal cofiring is generally not cost competitive in the current energy market, cofiring offers benefits that could result in more widespread cofiring under certain policy scenarios. We judge that the most important application of cofiring is as a way to achieve significant near-term reductions in CO_2 emissions. Its potential as a CO_2 mitigation strategy depends on its competitiveness with other control strategies. If costs of NO_x and SO_x emissions are accounted for, cofiring could reduce CO_2 emissions from the coal-fired electricity generation sector by 10% (about 3% of U.S. emissions) at a carbon price of about 50 \$/tC (Figure 4b), significantly smaller than the near-term cost of roughly 100 \$/tC or larger for reducing emissions by replacing existing capacity with nonfossil sources such as wind or nuclear or by building new plants or retrofitting existing coal-fired plants to capture and store CO_2 (46–48). Moreover, cofiring can achieve significant reductions in CO_2 emissions in the very near term (less than 5 years).

One might assume that biomass cofiring would have limited utility in mitigating CO_2 emissions because coal-fired generation might be rapidly eliminated from the electric market as the stringency of constraints on CO_2 emissions increases (44). If the price of natural gas remains low and stable, then it seems likely that a CO_2 constraint would rapidly eliminate coal-fired capacity because substantial emissions abatement could be achieved by switching from coal to natural gas and “carbon-ordered dispatch” (22, 46). However, if natural gas prices rise significantly, the future of coal under CO_2 constraints is less certain. First, with limited use of energy crops—as opposed to the residues considered in our analysis—biomass cofiring can plausibly achieve significantly larger decreases in electric sector CO_2 emissions. Second, as we describe in the Technical Feasibility Section, there is little doubt that biomass-to-coal cofire ratios could be increased beyond the maximum of 20% considered here; higher ratios might permit an economically efficient strategy in which some coal-fired generation is retired, while the remainder uses a gradually increasing fraction of biomass for generation. Finally, if CO_2 capture and sequestration (CCS) technologies are viable (48, 49), then coal-based CCS may well become the base-load generating technology of choice,

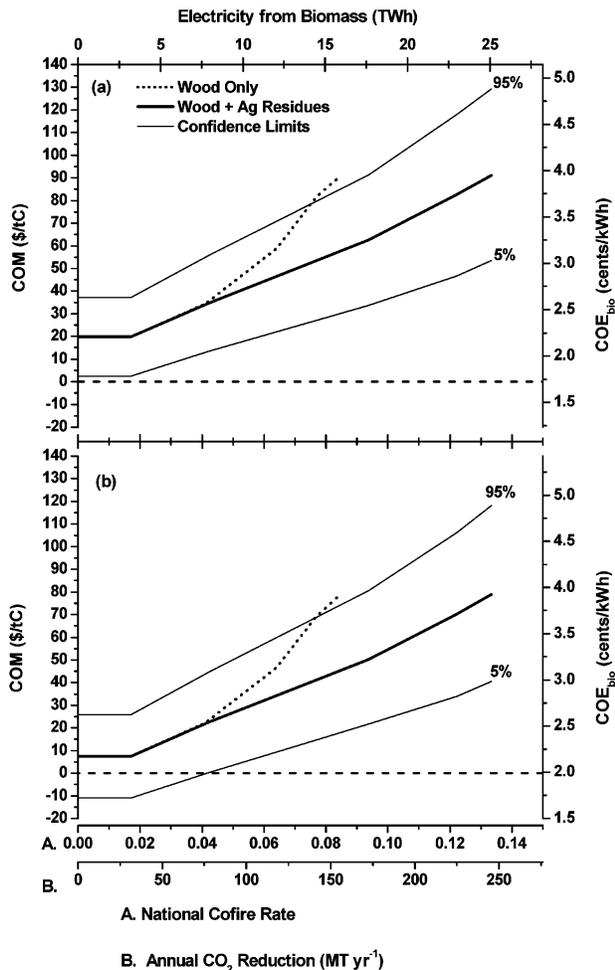


FIGURE 4. National supply curve for the cost of carbon mitigation (COM) and the cost of biomass electricity from cofire as a function of the national cofire rate. Part (a) does not include the credit for reduction of sulfur and nitrogen emissions due to cofiring; these credits are included in part (b). The confidence limits (5% and 95%) apply to the wood plus agricultural residues case and are from Monte Carlo simulation using the distributions for capital costs, O&M costs, and biomass fuel properties listed in Table 1. The dashed horizontal line indicates a cost of mitigation of 0 \$/tC.

particularly if gas prices rise above about 3.5 \$/GJ (46). Biomass is compatible with CCS; using these technologies on power plants firing biomass or biomass-coal mixtures can achieve electricity generation with negative net CO₂ emissions (50, 51).

This analysis also suggests that cofiring is a very cost-effective use of biomass. The low capital costs and relatively high efficiency of cofiring make it more competitive than many proposed advanced biomass technologies. Another use of biomass is to produce liquid fuels such as ethanol that can be substituted for, or more practically blended with, gasoline to reduce CO₂ emissions. Most current ethanol production is from corn at very high cost (including subsidies) making it very uneconomic as a means of CO₂ mitigation. There is great interest in the possibility of producing ethanol from lignocellulosic biomass such as residues and energy crops, the same biomass sources that could be used for cofiring. It is therefore reasonable to compare the cost of reducing CO₂ emissions accomplished by cofiring and biomass ethanol production. Realistic projections of the cost of cellulosic ethanol suggest that the near-term costs will exceed 1 \$/gallon which is equivalent of a carbon mitigation cost of order 200 \$/tC (at a petroleum price of 25 \$/bbl) (52, 53). It therefore appears that cofiring is a far more cost-

effective method of reducing CO₂ emissions than liquid fuel production from a given biomass supply. On the other hand, bioethanol offers energy-security benefits not considered here.

While there is yet no national commitment to reduce CO₂ emissions, policies such as federal tax credits or state-level initiatives exist to promote renewable energy production (54). Many of these programs, however, explicitly rule out biomass cofiring. This appears to be due, in part, to a desire to promote high technology solutions such as wind and solar energy and, perhaps, to a desire to prevent coal-fired generators from taking advantage of an environmental tax credit. Figure 4 indicates that cofiring could double U.S. current non-hydro renewable electricity production at a cost of less than 4 cents/kWh using wood residues; higher levels are achievable if one also considers agricultural residues. Four cents/kWh can be viewed as a best-case cost of new wind capacity, the fastest growing renewable technology (55, 56). Therefore, unless specifically excluded, cofiring will likely be an important response to policy tools to encourage renewable energy production such as renewable portfolio standards or tax credits.

The most economically efficient methods for achieving carbon reductions are policies that set an even price on carbon emissions using either taxes or tradable permits. Such mechanisms are particularly appropriate in the electric sector where there already are successful trading systems for SO₂ and NO_x. Under an economically efficient emissions constraint, we expect that biomass cofiring would be one of the first technologies to be widely implemented because of its low cost of mitigation, low capital costs, and technological maturity. It is important that policies to reduce CO₂ emissions do not arbitrarily exclude cofiring from the solution mix.

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Appendix B

BIGCC-CCS paper in *Biomass and Bioenergy*



Engineering economic analysis of biomass IGCC with carbon capture and storage

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Abstract

Integration of biomass energy technologies with carbon capture and sequestration could yield useful energy products and negative net atmospheric carbon emissions. We survey the methods of integrating biomass technologies with carbon dioxide capture, and model an IGCC electric power system in detail. Our engineering process model, based on analysis and operational results of the Battelle/Future Energy Resources Corporation gasifier technology, integrates gasification, syngas conditioning, and carbon capture with a combined cycle gas turbine to generate electricity with negative net carbon emissions. Our baseline system has a net generation of 123 MW_e, 28% thermal efficiency, 44% carbon capture efficiency, and specific capital cost of 1,730 \$kW_e⁻¹. Economic analysis suggests this technology could be roughly cost competitive with more conventional methods of achieving deep reductions in CO₂ emissions from electric power. The potential to generate negative emissions could provide cost-effective emissions offsets for sources where direct mitigation is expected to be difficult, and will be increasingly important as mitigation targets become more stringent.

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Keywords: Biomass; Gasification; IGCC; Carbon capture; Carbon mitigation

1. Introduction

Stabilizing atmospheric carbon dioxide (CO₂) concentrations at a level sufficient to avoid

dangerous interference with natural systems—the agreed goal of the Framework Convention on Climate Change—presents a fundamental challenge to industrial society. Biomass has long been investigated both as a (nearly) CO₂ neutral substitute for fossil fuels and as a means of offsetting emissions by sequestering carbon in terrestrial ecosystems [1]. The relatively recent

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development of carbon capture and storage (CCS) technologies, conceived as a means toward fossil fuel use without atmospheric CO₂ emissions, provides a new suite of opportunities for biomass energy systems (biomass-CCS). This integration may yield distinct advantages by providing useful energy products and effectively removing carbon from the atmosphere–biosphere system.

We survey possible routes to biomass-CCS and present a simplified engineering economic model of a feasible, though non-optimal, biomass integrated gasification combined cycle (IGCC) system with CO₂ capture to illustrate the potential role and importance of biomass-CCS. The model is based on previously published process models and associated component cost estimates for major subsystems [2–4]. Our analysis focuses on system integration including: identification of component technologies and integration points; design modification to facilitate integration; integrated process stream modeling; and integrated economic modeling.

Three versions of the model are presented, two with CCS and a baseline without. Additional design alternatives exist as do alternate component technologies; no optimization has been performed. Moreover, alternate subsystem technologies, such as oxygen-blown gasification, could be applied to biomass fuels with potentially higher energy efficiency and fuel carbon capture rates. Assessing the engineering economic trade-offs of various systems for capturing CO₂ from biomass electricity or poly-generation systems is an important area for future research.

Section 2 discusses key issues for a biomass-CCS mitigation strategy and surveys possible biomass-CCS pathways. Technical and economic details of the current model are presented in Section 3. Section 4 provides both direct modeling results and a broader context within which these results can be interpreted. Finally, Section 5 discusses the implications of our results.

2. Background

CCS is primarily aimed at decoupling the fossil fueled energy sector from atmospheric carbon

emissions. Integration of CCS with biomass energy systems could leverage similar technologies for a distinctly different benefit: effective generation of negative atmospheric carbon emissions as atmospheric carbon—fixed through photosynthesis—is captured and sequestered from the atmosphere for geologic timescales.

Biomass generally provides four routes for carbon mitigation: in situ sequestration by reforestation and conservation; remote sequestration by harvest and burial; substitution for fossil fuels; and substitution for fossil fuels with remote sequestration (biomass-CCS) [5,6]. Only biomass-CCS can both provide low-carbon energy products and effectively remove carbon from the natural carbon cycle. As a result, biomass-CCS offers the largest mitigation per unit biomass, or equivalently per unit land area, potentially important given limited agricultural resources [7].

Top-down estimates of the economics of stabilizing atmospheric CO₂ at an effective doubling of pre-industrial concentrations without biomass-CCS suggest marginal mitigation costs could exceed 1000 US dollars per metric ton carbon mitigated ($\$tC^{-1}$) [8]. These high marginal costs arise where *direct* mitigation is expected to be difficult, as in the transportation sector where the combination of mobile emissions sources and strong consumer performance expectations will likely drive up the cost of mitigation [9]. Negative emissions from biomass-CCS could offset these sources, providing *indirect* mitigation, at potentially lower cost. At the project level, sale of internally generated emissions offsets could provide additional revenues, depending on the carbon management and regulatory framework.

Three technological approaches are being advanced for fossil CCS: post-combustion capture (PCC), where CO₂ is scrubbed from combustion exhaust streams; oxyfuel, where combustion occurs in pure oxygen and CO₂ is separated by condensing water from the exhaust; and pre-combustion separation (PCS), where carbon is separated prior to combustion by gasification (of solid fuels), steam reforming, shift, and CO₂ scrubbing [10,11]. Note that PCS systems are uniquely flexible in their potential energy products, including gaseous fuels (e.g., hydrogen), liquid

fuels (e.g., methanol), or electricity, and may have cost advantages relative to PCC for new plants from lower energy requirements for carbon separation and higher conversion efficiencies of gas turbine and fuel cell power plants [10,12].

Biomass has important similarities with fossil fuels (particularly coal), including conversion technologies and the range of energy products that can be generated—dispatchable, base-load electricity as well as liquid and gaseous fuels. As a result, all three technological routes for CCS could be applied to biomass energy systems. Biological processes, such as bio-ethanol fermentation, provide additional CCS opportunities. Fig. 1 illustrates the major routes to biomass-CCS.

PCC or oxyfuel could be integrated with modern biomass boiler technologies or retrofitted to existing plants, though the small scale and low efficiency of existing biomass boilers would make this relatively inefficient. Alternatively, coal-fired power plants could be retrofitted to co-fire biomass *and* incorporate CCS such that biomass

carbon captured would more than offset incomplete capture of coal carbon [13]. With sufficiently stringent emissions controls, such a plant could be retrofitted to burn only biomass. The feasibility of this depends on (i) emissions controls inducing both a low purchase price for unmodified coal-fired power plants and (ii) financial dominance of large negative emissions over potentially high fuel costs, as well as (iii) local access to very large biomass resources.

Modern biomass gasification technologies could incorporate PCS. Syngas dilution with atmospheric nitrogen largely eliminates the benefits of PCS in air-blown gasification systems. However, indirectly heated, steam-blown systems or oxygen-blown systems could effectively leverage PCS. Oxygen-blown biomass gasification has been demonstrated and offers higher energy efficiencies and carbon capture; though somewhat less operating experience and economic data is available for these systems [14,15]. The current analysis is therefore modeled from the Battelle Columbus

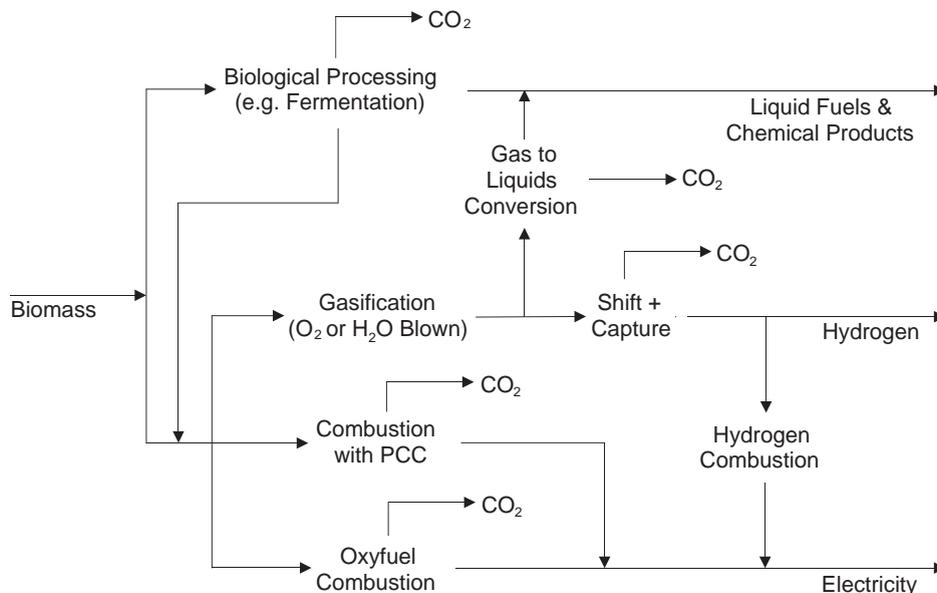


Fig. 1. Routes to biomass with CO₂ capture. The routes to biomass energy products with CCS include (from top to bottom) biological processing with capture of CO₂ by-products to produce liquid fuels, biomass gasification with shift and CO₂ separation to produce hydrogen, and biomass combustion to produce electricity with CCS—either by oxyfuel or PCC routes. These basic routes can be combined or integrated, for example, by gasification with CCS of residual biomass from biological processes, or by syngas conversion to liquid fuels with CCS, or by burning hydrogen-rich syngas to produce electricity with CCS—as in the current study.

Laboratory/Future Energy Resources Corporation (BCL/FERCO) steam-blown system [2].

Biological processes provide additional opportunities for biomass-CCS. CO₂ is a byproduct of fermentation in bio-ethanol production, implying that CO₂ available for capture scales with ethanol production and that fuel carbon capture rates scale with conversion efficiency. The retrofit potential of this strategy implies nearly 9 Mt C yr⁻¹ is available at very low capture cost given global bio-ethanol production of approximately 40 Mm³ in 2003 [16]. Bio-ethanol production generally also includes combustion—of waste biomass, providing further carbon capture opportunities, with additional cost [17].

The ability to generate emissions offsets extends the scope of carbon mitigation with biomass and may provide cost-effective mitigation alternatives across the economy, fundamentally changing the economics of biomass-based mitigation. Negative emissions from biomass-CCS do not, however, offer a strict cap on mitigation costs since its costs must scale with the biomass supply curve, which may become steep if large-scale bio-energy crops compete for limited land resources. Environmental impacts may further constrain biomass mitigation potential [1]. However, the extraordinary heterogeneity of emissions sources provides many niches, and integrating CCS will extend the opportunities for biomass-based mitigation.

3. Methods

The simplified engineering economic model presented here was developed by integrating previously published ASPEN simulation results with associated cost estimates from several independent studies [2–4]. We do not claim that our cost and performance estimates represent today's realities; rather, they reflect a prospective view assuming a design benefiting from at least 10 years of aggressive research and development to refine component technologies and reduce requisite contingencies. These assumptions are consistent with and incorporated directly from the underlying process simulation studies.

3.1. Process design

The model includes four component subsystems: biomass gasification, syngas conditioning, carbon capture, and power generation (see Figs. 2 and 3). Gasification and syngas conditioning subsystems are modeled from two studies of the BCL/FERCO indirect gasifier [2,3]. Carbon capture and compression is incorporated from a design study of coal gasification with PCS [4]. The gas turbine combined cycle (GTCC) system is based on GE's H-class technology with performance modifications to accommodate hydrogen-rich fuel gas [18,19].

An integrated design is modeled from process blocks in the above-mentioned studies with minor

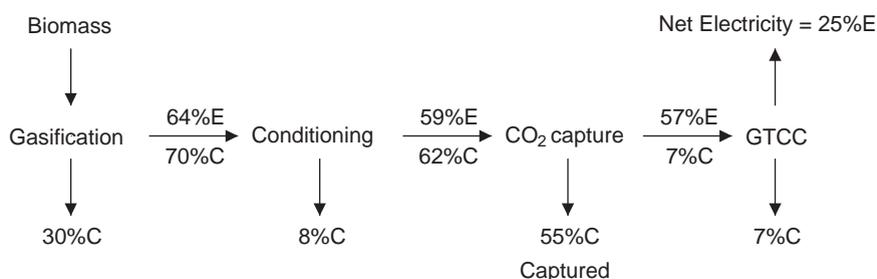


Fig. 2. Process schematic with carbon and energy flows. A general schematic with carbon and energy flows illustrates the 25% net efficiency and 55% carbon capture rate of the biomass-CCS system with steam reforming. Note that nearly 30% of the biomass carbon is emitted during char combustion, a peculiarity of this gasification system, and an additional 11% is emitted to provide heat for steam reforming. Eliminating steam reform avoids this loss, but reduces the CO₂ available for capture and results in additional emissions from the gas turbine.

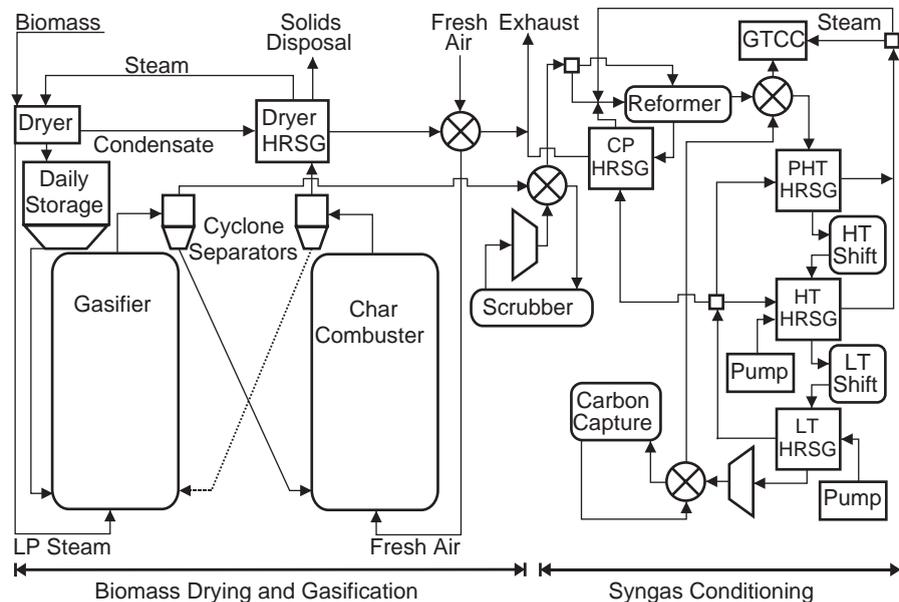


Fig. 3. Process flows for gasification and syngas conditioning with steam reform. Key aspects of the gasification and syngas conditioning design include (i) the close integration of gasifier and char combustor, fundamental to the BCL/FERCO design, (ii) the close coupling of the gasifier and dryer systems, from the design by Raymond et al. [3], (iii) the steam sources for reform and shift reactors, and (iv) the steam diversion and syngas heating for fuel gas humidification.

modifications to balance stream compositions, pressures, temperatures, and flow rates so as to conserve heat, chemical energy, and mass. These modifications include (i) scaling of component technologies, (ii) substitution of process heat sources and uses, (iii) addition of supplemental generation capacity, and (iv) addition and heat duty modification of heat exchangers. Models of transformation from input to output streams for individual process blocks are linearly scaled from the original subsystem analyses (e.g., CH_4 in the steam reformer output is $\sim 41\%$ of the CH_4 input based on Ref. [2]).

The BCL/FERCO system is unique in that heat for gasification is provided indirectly by char combustion in a separate reaction vessel. Circulating sand provides heat transfer between the combustor and gasifier (Fig. 3). This system avoids syngas dilution with nitrogen; however, roughly 30% of fuel carbon is emitted as char combustor flue gas. These losses are inherent to indirectly heated (non-oxygen) systems; design modifications could limit them (with additional cost), but they

are not explored here. The BCL/FERCO system also appears to have relatively high throughput, high-energy efficiency, and capital cost advantages relative to other biomass gasifiers [3]. Although the system is not yet in commercial use, a demonstration facility with a capacity roughly one-sixth that modeled here is in operation at the McNeil Station in Vermont [20].

The gasifier converts $\sim 23\%$ of input carbon to methane and higher hydrocarbons. Addition of steam reforming prior to water–gas shift improves the carbon capture rate by shifting some of the methane to CO_2 , CO and H_2 , but raises costs and lowers energy efficiency as we describe in Section 4.

Integration of gasification with syngas conditioning is addressed in an NREL study [2]; however, that study included sophisticated integration of gasification, conditioning, and a pressure swing adsorption (PSA) system to produce high purity hydrogen. We replace the PSA with a glycol scrubber, which is more cost effective given lower purity requirements. Several modifications,

Table 1
Comparison of gas streams integrating biomass gasification and CO₂ capture

Parameter ^a	Scrubber input as modeled here ^b	Syngas from NREL study ^c	Scrubber input from IGCC study ^d
H ₂	61%	62%	58%
CO ₂	35%	34%	37%
CH ₄	3%	3%	4%
CO	1%	1%	0%
Molar flow (Mmol h ⁻¹)	5.3	2.6	5.3
Temperature (°C)	13	24	13
Pressure (Mpa)	3.1	2.6	3.1
Cold gas HHV (MW _{th})	255	118	252

^aUnits are mole fractions or as noted. Chemical components representing less than 1% of the molar flow are omitted. Mole fractions do not add to one due to rounding errors and omitted compounds.

^bFrom the current model BIGCC-CCSr (with steam reform).

^cFrom the NREL study of biomass gasification for hydrogen production [2].

^dFrom the study by Doctor et al. of coal IGCC-CCS [4].

described below, were required to isolate the gasifier, reformer, and shift reactors from the PSA and balance of plant.

A steam dryer assembly from a more recent study of the BCL/FERCO system by the Weyerhaeuser Corporation [3], is substituted for the rotary dryer in the NREL study. Both use char combustor exhaust for biomass drying, but the steam system also provides gasifier steam, freeing up downstream process heat. The steam system has efficiency and emissions benefits as well. Syngas composition and production rates from the Weyerhaeuser study are integrated through downstream process blocks for consistency.

Heat for steam reforming is provided by combusting roughly 12% of unreformed syngas outside the reaction tubes. This was estimated by balancing the heat required for reform (change in enthalpy of formation and sensible enthalpy across the reformer) with the heat available from combustion (lower heating value of unreformed syngas minus the change in sensible enthalpy of combustion products to 100 °C above the syngas output). We assume 98% heat transfer efficiency throughout. An alternate design burning hydrogen-rich fuel gas to minimize carbon losses was also explored, as discussed below.

Finally, available process heat is applied to preheat the fuel gas and raise steam for the reformer, shift reactors, fuel gas humidification,

and supplemental power generation, whereas the NREL study took an economic credit for steam as a co-product. Fig. 3 presents a schematic of the gasification and syngas conditioning subsystems.

The CO₂ capture sub-system is incorporated without modification from the design by Doctor et al. [4]. It is integrated after the low temperature shift heat recovery steam generator (LT HRSG in Fig. 3), where the modeled stream composition is nearly identical to that in the original design, as shown in Table 1. Minor pressure and temperature differences in these streams are addressed by incorporating additional compression and adjusting the heat rate of the capture system's heat exchanger. The flowrate difference in these streams is addressed by scaling up the gasifier and syngas conditioning sub-systems. Separated CO₂ is compressed to 145 bar for pipeline transport while the lean solvent is compressed, refrigerated, and recycled [4,21].

The GTCC system incorporates fuel gas humidification of 0.6 kg steam kg⁻¹ fuel by blending the fuel with steam at the same pressure [18]. We assume net conversion efficiency of 60% (LHV) for the GTCC, consistent with current H-class technology [19]. We assume (optimistically) that comparable technology will be available at the 100 MW_e scale within the time horizon of this analysis, though it is currently available only at the 400 MW_e scale.

Table 2

Summary model results. The BIGCC-CCSr system includes steam reforming while BIGCC-CCS does not

System	BIGCC	BIGCC-CCS	BIGCC-CCSr
<i>Process performance</i>			
Capacity (MW _{th})	444	444	444
Net generation (MW _e)	149	123	110
Net efficiency (HHV)	34%	28%	25%
C-capture rate (% input C)	0%	44%	55%
Net emissions (kgC kWh ⁻¹) ^a	0	-0.14	-0.20
<i>Economic performance</i>			
Capital cost (\$ kW ⁻¹)	\$1,250	\$1,730	\$1,980
Non-fuel O&M cost (\$ kW ⁻¹ y ⁻¹) ^b	\$100	\$131	\$146
Electricity cost (cents kWh ⁻¹) ^c	5.9	8.2	9.3
Cost of carbon mitigation (\$ tC ⁻¹) ^d	\$102	\$123	\$135

^aIgnoring minor emissions from fossil energy consumed in biomass production, harvest, transport and processing, generally less than 5% of biomass energy [22].

^bAssumes a capacity factor of 0.8.

^cAssumes Biomass fuel cost and CO₂ sequestration cost of \$50 per dry ton and \$10 per ton, respectively, as well as amortization of capital costs at 10% interest over 20 years.

^dComputed relative to pulverized coal power generation with fuel, capital, non-fuel O&M cost, and net efficiency of 1.0 \$GJ⁻¹, 1.2 \$W⁻¹, 8 \$MWh⁻¹, and 40% (HHV), respectively; coal and biomass carbon intensities of 24 and 25 kg C⁻¹ GJ⁻¹, respectively, with the same amortization and utilization assumptions outlined above. These assumptions yield coal electricity cost of 37 \$MWh⁻¹.

3.2. Economics

Our economic model is consistent with estimates and assumptions in the original literature. Cost estimates for components in the gasification and syngas conditioning systems are developed from those in the NREL and Weyerhaeuser studies [2,3]. Cost estimates for the carbon capture system are from those by Doctor et al. [4]. All capital cost scaling was calculated using scaling factor of 0.7 (component costs are assumed to be proportional to the equipment size raised to the 0.7 power).

Capital costs were converted to year 2000 dollars using the Component Cost Index for Chemical Processes. Economic assumptions for contingencies and other allocations from individual studies were applied to their respective components to estimate the total capital requirement. The total capital requirement for the GTCC system is assumed to be \$550 per installed kW_e. We assume a CO₂ sequestration cost of \$10 ton⁻¹, to pay for pipeline transport to an appropriate storage facility, final compression, and geological sequestration [11].

Non-fuel operation and maintenance cost estimates are also developed from the original literature [2–4]. Cost drivers include labor, consumable material (catalysts, sorbent, etc.), ash and sand disposal, maintenance, insurance and local taxes, royalties, and other operating costs. A capacity factor of 0.8 is assumed for all calculations.

4. Results

Summary cost and performance results are presented in Table 2 for two biomass IGCC systems with carbon capture—BIGCC-CCSr with steam reforming and BIGCC-CCS without—and the base case system without carbon capture. All three systems assume a thermal capacity of 444 MW_{th}, equivalent to roughly 2100 bone-dry t d⁻¹. Net generation for the three systems are 110, 123, and 149 MW_e, respectively, and carbon capture rates—equal to the fraction of fuel carbon captured as CO₂—are 55%, 44%, and 0%, respectively. Not surprisingly, net generation and

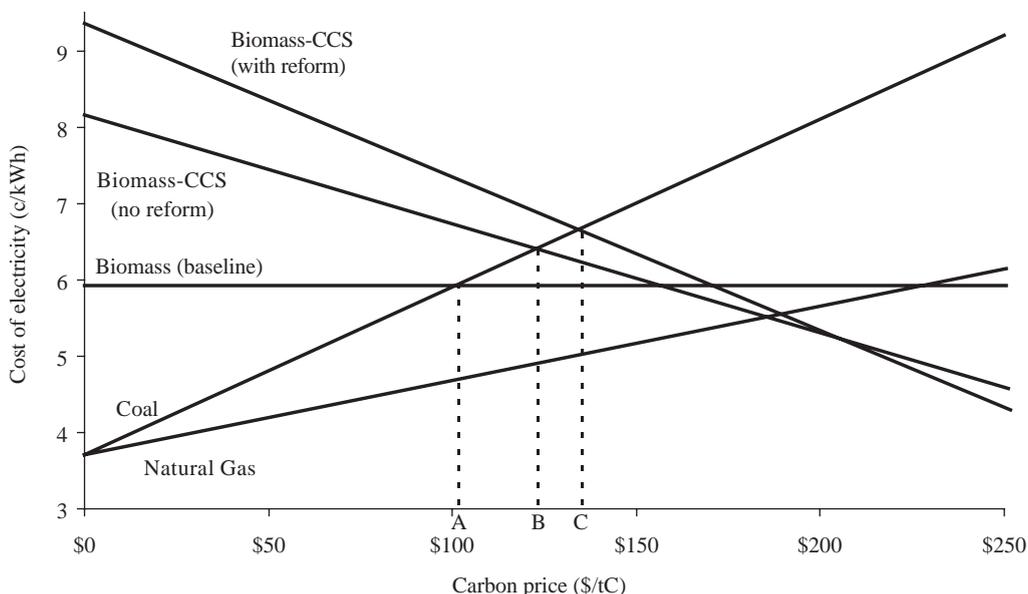


Fig. 4. Cost of electricity as a function of carbon price. Electricity costs are plotted for biomass-CCS with steam reform, biomass-CCS without steam reform, biomass without CCS, conventional pulverized coal, and conventional natural gas combined cycle technologies. The decreasing electricity cost with increasing carbon price from the two biomass-CCS cases reflects the net negative carbon emissions from these technologies. The relative slopes and electricity costs at zero carbon prices illustrate the trade-off between cost and carbon capture efficiency. Carbon mitigation costs are equal to the carbon price associated with the intersection of electricity costs from a mitigation technology and the base case technology, defined as coal within this context. As such, the mitigation costs for non-capture biomass IGCC, biomass-CCS without steam reform, and biomass-CCS with reform are equal to points “A”, “B”, and “C” respectively. Note that as carbon prices approach $200 \text{ } \$\text{tC}^{-1}$, biomass-CCS becomes the least cost technology. Parameter values for the biomass technologies are taken from Table 2. To simplify the graph, parameter values for conventional technologies are deliberately set to yield equal electricity costs with zero carbon price—specifically capital costs, fuel costs, non-fuel O&M costs, and energy efficiencies (HHV) for coal and natural gas are 1200 and $550 \text{ } \$\text{kW}^{-1}$, 1.00 and $3.46 \text{ } \$\text{GJ}^{-1}$, 8 and $3 \text{ } \$\text{MWh}^{-1}$, 40% and 50% , respectively.

carbon capture rates scale in opposite directions as increasing carbon capture is associated with decreasing thermal efficiency and increasing parasitic load. This efficiency penalty, combined with increasing capital requirements, causes specific capital costs ($\text{\$kW}^{-1}$) and electricity costs to increase with carbon capture rate, as illustrated in Table 2. The trade-off between cost and carbon capture in the two CCS cases provides an example of how CCS deployment will be dominated by economic optimizations rather than fundamental technological constraints.

The economic implications of these results are ambiguous absent comparison to competitive electric sector technologies. Fig. 4 provides this context by plotting the cost of electricity for the systems modeled here as well as for conventional

coal and natural gas technologies as a function of carbon price.

Electricity costs for the two fossil fuel technologies are low with zero carbon price, around $3.7 \text{ cents } \text{kWh}^{-1}$ (note that the parameters have been adjusted to yield equal electricity costs absent carbon constraints to simplify the figure). However, fossil fuel electricity costs increase in proportion to their fuel carbon intensity divided by their net (HHV) efficiency. As a result, costs increase much faster for coal than natural gas. The cost of biomass electricity without CCS, the conventional view of biomass electricity, is higher than that of fossil fuels with zero carbon price, but has zero slope, reflecting the general balance in carbon emissions and CO_2 uptake during biomass production. Fossil emissions associated with

biomass production, harvest, and transport are generally small—representing fossil energy less than 5% of biomass energy—and are ignored here [22]. As an aside, note that this curve is broadly similar to those expected from fossil fuel technologies with CCS [23]. Finally, the two biomass-CCS cases have electricity costs substantially higher than the base line biomass technology due to their higher capital costs and lower net efficiencies. However, their costs decrease in proportion to their carbon capture rate, reflecting an economic credit for negative carbon emissions. As carbon prices increase, biomass-CCS becomes increasingly cost effective and with sufficiently high prices ($\sim 200 \$tC^{-1}$) biomass-CCS becomes the least-cost electric sector technology.

Mitigation costs can be read directly from Fig. 4 as the carbon price where electricity costs from a particular mitigation technology equals that of the conventional baseline generation technology. From the case illustrated, the mitigation costs are calculated as 102, 123, and 135 $\$tC^{-1}$ for the base case, capture system without reform, and capture system with reform, respectively—assuming pulverized coal as the conventional baseline technology. These results should not be interpreted too precisely, due to our simplified modeling techniques. However, they do indicate mitigation costs for BIGCC-CCS to be somewhat higher than those expected from fossil fuel systems with CCS [23]. While we believe that process and component technology optimization will likely improve these economics, our results do not suggest that biomass-CCS will dramatically reduce mitigation costs from biomass or in the electric sector more generally. However, even without substantial improvements, biomass-CCS will likely be cost-competitive, and substantially reduce total mitigation costs, for mitigation beyond the electric sector (via emissions offsets)—where, as discussed above, costs may exceed $1000 \$tC^{-1}$. In this context, biomass-CCS may eventually face competition from technologies for direct capture of CO_2 from the air. However, such systems are substantially less proximate and more uncertain than biomass-based options. As such, biomass-CCS has the potential to expand the niches available for biomass-based mitigation.

We assume pulverized coal combustion (PC coal) as the baseline electric sector technology for mitigation cost calculations. As shown in Fig. 4, however, switching from PC coal to combined cycle natural gas turbines (GTCC) could provide zero cost mitigation, and would push the mitigation cost of biomass up to nearly $200 \$tC^{-1}$ —with or without CCS.

This interpretation hinges on the cost of natural gas. Natural gas prices are historically variable and estimates of future prices are highly uncertain. The natural gas price used here, $3.46 \$GJ^{-1}$, is likely optimistic given current futures market expectations [24]. Moreover, a wholesale conversion of the electric sector to natural gas, implied by the interpretation outlined above, would dramatically increase demand and drive up fuel costs. Under our assumptions, GTCC is *never* the least cost technology if the natural gas price were to increase by 40%. Uncertainty about gas prices may encourage power companies to maintain significant coal generation in their portfolios as a hedge against natural gas price fluctuations. Of course, uncertainty about future carbon constraints will weigh against building new PC coal, but not against maintaining existing units. In short, while GTCC is very important, we believe PC coal is the appropriate baseline for mitigation cost estimates, as presented in Table 2.

As noted above, a design alternative providing reformer heat by diverting and burning a portion of hydrogen-rich fuel gas (post carbon capture), rather than unreformed syngas, was explored to increase the carbon available for capture. This option yields net efficiency, carbon capture rate, specific capital cost, and mitigation cost of 21% (HHV), 62%, $2.29 \$W^{-1}$, and $152 \$tC^{-1}$, respectively, continuing the trend of increasing carbon capture with increasing cost.

Finally, experimental data from the Battell/FERCO designed pilot plant facility in Burlington, Vermont, show that the syngas composition from the pilot plant matches closely with that modeled here and that this composition is relatively insensitive to variations in fuel type, moisture, or feed rate [20]. However, the data do suggest two possible updates to the model presented here. First, the maximum capacity of the pilot plant has

been demonstrated to be 75% greater than the design capacity. This suggests a potential 32% reduction in the gasifier's specific capital cost [$1-(1/1.75)^{0.7}$] relative to the current modeling assumptions. Second, the carbon conversion rate of the pilot plant is closer to 60% compared with nearly 70% currently modeled. This decreased carbon conversion would translate into decreased net plant efficiency, decreased carbon capture efficiency, and increased specific capital costs. Incorporating these values yields net efficiency, carbon capture rate, specific capital cost, and mitigation cost of 21% (HHV), 47%, $1.84 \$ W^{-1}$, and $152 \$ tC^{-1}$, respectively, for the biomass-CCS system with steam reform.

5. Conclusions

The general arguments presented in Sections 1 and 3, and the specific system design of Section 2 demonstrate that the generation of negative atmospheric carbon emissions by integrating CCS and biomass energy technologies is both feasible and potentially important. The design discussed here represents one possible system; other designs will likely have technical and economic advantages (e.g., oxygen-blown gasification) and be easier to deploy in the near term (e.g., capture of bio-ethanol fermentation off-gases).

Regardless of the specific route, the ability of biomass-CCS to generate negative atmospheric carbon emissions could fundamentally change the role of biomass in achieving deep emissions reductions by providing a mechanism to offset emissions anywhere in the economy. These offsets provide additional flexibility to a broader portfolio of carbon mitigation strategies. Moreover, the well-mixed nature of atmospheric CO_2 implies that biomass-CCS offsets could mitigate emissions anywhere in the world, providing opportunities to affect agricultural economics in developing countries by subsidizing domestic consumption of primary agricultural commodities (i.e., energy products) with exported emissions offsets.

Finally, the mitigation costs associated with electric sector biomass-CCS appear similar to more conventional electric sector technologies.

Therefore, biomass-CCS should be considered more generally in the context of achieving deep emissions reductions. However, the mitigation costs associated with biomass-CCS are likely to be more compelling as emissions targets force mitigation beyond the large-scale, centralized sources of the electric sector.

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Appendix C

BIGCC-CCS model documentation

Appendix C

BIGCC-CCS Model Documentation

This appendix is divided into three sections. Section C1 characterizes the engineering model, describing each process modeling block, the inputs and outputs, and relevant modeling theory and equations. Section C2 characterizes the economic model, describing the computation of both capital and operating costs. Finally, Section C3 provides underlying process flow data for the model, including each those for each component input and output stream characterized in Section C1. Figures 3.4 – 3.7 will be important references in interpreting this Appendix.

Note that the model characterized herein is strongly tied to previously published design studies with process simulation data [1-4]. The focus of current modeling efforts is on integration of component technologies as they were described in the original process simulations, including: identification of component technologies and integration points; design modification to facilitate integration; integrated process stream modeling; and integrated economic modeling. These are discussed in detail in Chapter 3 of the Thesis. The purpose of this Appendix is to provide a more technically detailed characterization of the model.

C1. Engineering model characterization

Gasifier. The steam drier, gasifier, and syngas cleaning components are modeled as a closed system (“black box”) based on the previously published process simulation study of these coupled components [1]. Specifically, the molar proportion of syngas carbon in the form of CO is calculated by dividing the mole fraction of syngas CO by the sum of the mole fractions of each other syngas compound multiplied the number of carbon atoms in each compound. The result is then multiplied by the published gasifier carbon conversion rate (70% from [1]) and by the molar rate of carbon input, which is defined by the dry biomass input rate (~80.2 t/hr) multiplied by the mass fraction carbon in biomass (~50.2%) divided by the molar mass of carbon (12 g/mole). The result defines the CO flow rate in the Clean Syngas process stream. Molar flow rates for the balance of syngas compounds in this stream are modeled by multiplying the modeled CO flow rate by the ratio of each compound’s mole fraction in the syngas to CO’s mole fraction in the syngas.

Summary:

- Input stream(s): Wood Input to gasifier
- Output stream(s): Clean Syngas
- Reference: [1]

Syngas compression. Compression is necessary for certain downstream process, including syngas reform and shift. Model configurations with these downstream processes (all those with CCS) include syngas compression of Clean Syngas. This system component is characterized in the previously published process simulation [2].

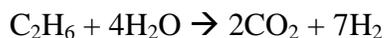
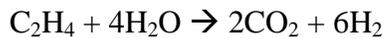
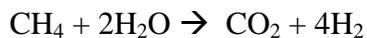
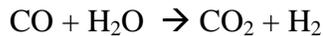
Based on this characterization, only changes to the pressure and temperature of the syngas are modeled here.

Summary:

- Input stream(s): Clean Syngas
- Output stream(s): Compressed Syngas (“Comp Syngas”)
- Reference: [2]

Steam reformer. The reformer is modeled based on the previously published process simulation [2], in which the component is described in detail. Steam reforming is not a necessary step; however, by converting CH₄ and higher hydrocarbons to CO₂ and H₂, it enables higher carbon capture rates. The downside of steam reforming is the energy and financial cost associated with this component. For the two model versions that include steam reform Compressed Syngas is mixed with Conditioning Steam to form the Reformer Syngas, which is subsequently passed through the catalyst-filled reaction tubes of the reformer. A separate Reformer Combustion stream is burned around the reaction tubes to provide heat for the endothermic reactions inside the reformer.

The steam requirement for the reformer is estimated from the molar ratio of steam to dry syngas in the reformer input stream in the original process simulation. The reformer reactions on the input streams are modeled with a two step calculation. In the first step, the molar flows of CO, CH₄, C₂H₄, and C₂H₆ are reduced in proportion to their reductions in the original process simulation [2]. In the second step, the molar flows of CO₂, H₂, and H₂O are balanced stoichiometrically, according to the reaction equations below:



The throughput of the Reformer Combustion stream is modeled by balancing the changes in enthalpy across reformer, assuming complete combustion. Specifically, the flow rate for this stream is set such that the change in enthalpy of formation during combustion minus the change in sensible enthalpy equals the change in enthalpy of formation during steam reform plus the change in sensible enthalpy. 98% heat transfer efficiency is assumed in these calculations. Euler's method is used to estimate the integral of sensible enthalpy change with temperature ("T") using an approximation of specific heat ("C_P") of the form $C_P = A + BT + CT^2 + DT^3 + ET^4$ [5]. The output temperature of the Reformed Syngas stream is set equal to that in the previously published process simulation [2]. The output temperature of the Combustion Products is set to 100K above the Reformed Syngas stream to ensure adequate heat transfer rates within the reformer. The input temperature of Reformer Syngas is modeled by a two-step process. First, the temperature of Conditioning Steam is modeled by assuming that gross thermal equilibrium is achieved between the multiple steam streams embodied in it, assuming constant C_P. Second, the temperature of the Reformer Syngas is modeled by assuming gross thermal equilibrium is achieved between the Conditioning Steam and the Compressed Syngas

streams using Euler's method to estimate the integral of sensible enthalpy change with T using an approximation of specific heat of the form $C_p = A + BT + CT^2 + DT^3 + ET^4$ [5].

Two design variants are developed for the source of the Reformer Combustion stream. In the design referred to as BIGCC-CCS_{R,SG} the Reformer Combustion stream is modeled as a diverted fraction of the Compressed Syngas stream. Accordingly, the fraction of syngas to be combusted ("*f*") can be defined in terms of the total net energy available if all the syngas were combusted (" E_C ") and the total net energy requirement if all the syngas were reformed (" E_R ") with the equation:

$$f \times E_C = (1 - f) \times E_R$$

– or –

$$f = \frac{E_R}{E_C + E_R}$$

In the design referred to as BIGCC-CCS_{R,FG}, the Reformer Combustion Stream is modeled as a diverted fraction of the hydrogen-rich Fuel Gas stream. In this case, 100% of the Compressed Syngas stream is reformed, and the fraction of Fuel Gas required to be diverted for the Reformer Combustion stream is defined with the equation:

$$f \times E_C = E_R$$

– or –

$$f = \frac{E_R}{E_C}$$

The Conditioning Steam process stream is modeled from four downstream heat recovery steam generator systems (“HRSG”), as described below.

Summary:

- Input stream(s): Reformer Syngas (= Compressed Syngas + Conditioning Steam) & Reformer Combustion (“Reformer Comb”)
- Output stream(s): Reformed Syngas & Combustion Products (“C P”)
- Reference: [2]

Reformer Combustion Product HRSG. The Combustion Products stream (“CP”) exits the Steam Reformer at a temperature of 1,224°K, 100°K greater than the Reformed Syngas exiting the reformer. This stream is directed to the Reformer Combustion Product HRSG (“Ref CP HRSG”) where its heat is largely transferred to a fraction of the Low Temperature Shift Steam (“LT Steam”), which was generated in the Low Temperature Shift HRSG.

The heat available in the CP stream is modeled with Euler’s Method to estimate the change in sensible enthalpy from 1,224°K to 511°K using an approximation of specific heat (“C_P”) of the form $C_P = A + BT + CT^2 + DT^3 + ET^4$ [5]. The heat required to raise the temperature of the LT Steam from 455°K to 811°K is estimated from the difference in enthalpies of steam at these two temperatures at 3.65 MPa, as provided by the NIST Chemistry WebBook, Thermophysical Properties of Fluid Systems, Isobaric properties for Water at a pressure of 3.65 MPa [6]. The quantity of steam throughput is estimated

by dividing the heat available by the heat required and multiplying the result by 0.98 to reflect a heat transfer efficiency of 98%.

The steam output (“CP Steam”) is blended with the Pre-High Temperature Shift Steam (“PHT Steam”) and High Temperature Shift Steam (“HT Steam”), as described below.

The Combustion Product Exhaust stream exiting the Ref. CP HRSG is assumed to be directed to the Char Combuster exhaust system downstream from its integration with the steam dryer assembly.

Summary:

- Input stream(s): Combustion Products (“CP”) LT Steam
- Output stream(s): Combustion Product Exhaust (“CP Exhaust”) Reformer Combustion Product Steam (“CP Steam”)
- Reference: [2]

Fuel Gas Heat Exchanger. Before entering the Pre-High Temperature Shift HRSG (“PHT HRSG”), the Syngas exiting the Steam Reformer (in configurations including steam reform) or exiting the compressor (in the configuration without reform) is cooled against the Hydrogen-Rich Fuel Gas (“H-Rich FG”) directly upstream from the Gas Turbine Combined Cycle power system (“GTCC”). The primary driver for incorporating this heat exchanger is to raise the H-Rich FG fuel gas temperature to ensure that steam added to maintain appropriate operating conditions in the gas turbine does not condense.

It is assumed that the steam will not condense if the partial pressure of water in the fuel gas stream after mixing, the Mixed Fuel Gas stream (“Mixed FG”), is substantially below the vapor pressure of water at the temperature of the Mixed FG stream. Raising the temperature of the H-Rich FG effectively raises the vapor pressure of water in the Mixed FG. This relation defines the minimum level of heat transfer in the Fuel Gas Heat Exchanger (“FGHX”). The vapor pressure of water in this stream is evaluated with the IAPWS-IF97 equations for water saturation pressure, as summarized by Bernhard Spang [7]. The partial pressure of water is evaluated by multiplying the mole fraction of water in the Mixed FG by the total pressure of this stream.

The FGHX has implications for downstream steam generation in the PHT HRSG – increasing heat transfer within the FGHX yields decreasing steam generation in the PHT HRSG. Steam from the PHT HRSG is used for Conditioning Steam with surplus used for supplemental power generation. Requirements for Conditioning Steam define the maximum level of heat transfer in the Fuel Gas Heat Exchanger for configurations with steam reform.

Finally, the FGHX has implications for the fraction of H-Rich FG to be diverted for Reformer Combustion in the model version BIGCC-CCS_{R,FG}. As described above, the quantity of the Reformer Combustion stream is set to balance the changes in enthalpy across the syngas reform and combustion sections of the Steam Reformer; however, increasing Reformer Combustion flow rates are associated with decreasing thermal efficiency (as less energy is released in the GTCC). The changes in enthalpies of

formation across the reformer are fixed by the compositions and chemical reactions of the Reformer Syngas and Reformer Combustion streams in the reformer. The changes in sensible enthalpy across the reformer are determined by the temperature changes (and compositions) of these streams. The input and output temperatures of the syngas stream are defined in the original process simulation [2]; the output temperature of the Combustion Products stream is defined in relation to the output temperature of the syngas stream; but the input temperature of the Reformer Combustion stream in the BIGCC-CCS_{R,FG} version of the model is determined by the level of heat transfer from syngas to H-Rich Fuel Gas in the FGHX. This is particularly relevant in this model version, given the relatively high quantities of water in the Combustion Products, with its associated C_p .

The level of heat transfer in the FGHX is set at the minimum required to avoid steam additions to the H-Rich fuel gas from condensing for model versions BIGCC-CCS_{NR} and BIGCC-CCS_{R,SG}—thereby maximizing steam production in the PHT HRSG. The level of heat transfer for the model version BIGCC-CCS_{R,FG} is set to the maximum possible that still allows sufficient steam generation in the PHT HRSG to support the Conditioning Steam requirements – thereby minimizing the change in sensible enthalpy of the Reformer Combustion stream in the reformer and minimizing the quantity of H-Rich fuel gas diverted away from the GTCC.

Summary:

- Input stream(s): Reformed Syngas
H-Rich Fuel Gas
- Output stream(s): Cool Reformed Syngas (“Cool Ref Syngas”)
Heated Fuel Gas
- Reference: [2]

Pre-High Temperature Shift HRSG. The Pre-High Temperature Shift HRSG (“PHT HRSG”) reduces the syngas temperature to the input temperature for the High Temperature Shift reactor (“HT Shift”), as defined in the original process simulation [2]. The heat is used to raise the temperature of LT Steam for Humidification of H-Rich Syngas, for Conditioning Steam, and supplemental power generation in certain model versions.

The heat available from the syngas stream is modeled with Euler’s Method to estimate the change in sensible enthalpy from 957°K to 643°K using an approximation of specific heat of the form $C_p = A + BT + CT^2 + DT^3 + ET^4$ [5]. The heat required to raise the temperature of the LT Steam from 455°K to 811°K is estimated from the difference in enthalpies of steam at these two temperatures at 3.65 MPa, as provided by the NIST Chemistry WebBook, Thermophysical Properties of Fluid Systems, Isobaric properties for Water at a pressure of 3.65 MPa [6]. The quantity of steam throughput is estimated by dividing the heat available by the heat required and multiplying the result by 0.98 to reflect a heat transfer efficiency of 98%.

Summary:

- Input stream(s): Cool Reformed Syngas (“Cool Ref Syngas”)
LT Steam
- Output stream(s): High Temperature Shift Input (“HT Shift Input”)
Humidification Steam (“Humid Steam”)
Pre-High Temperature Shift HRSG Steam (“PHT Steam”)
Supplemental Generation Steam (“Sup Gen Steam”)
- Reference: [2]

High Temperature Shift. Modeling of the HT Shift is adapted directly from the original process simulation [2]. CO in the output is set to 30% of the CO in the HT Shift Input stream on a molar basis, based on the original process simulation. Output flow rates of CO₂, H₂ and H₂O are modeled from the input flow rates with adjustments to stoichiometrically balance changes in the CO flow rate.

In the model version with HT Shift but without Steam Reform, Conditioning Steam must be added to the syngas so that the ratio of steam to dry syngas in the HT Shift Input stream matches that in the original process simulation [2]. In this version, Conditioning Steam is composed of HT Steam and PHT Steam. The mixing of the Conditioning Steam with the syngas is assumed to take place in the HT Shift and is modeled by assuming gross thermal equilibrium between these streams is achieved. Note that the temperature of the syngas leaving the PHT HRSG (“HT Shift Input”) is somewhat higher in this model version so that the temperature after mixing with the steam is consistent with the HT Shift input temperature in the original process simulation [2].

Summary:

- Input stream(s): High Temperature Shift Input (“HT Shift Input”) Conditioning Steam (“Cond Steam”) in BIGCC-CCS_{NR}
- Output stream(s): High Temperature Shift Output (“HT Shift Output”)
- Reference: [2]

High Temperature Shift HRSG. Modeling the High Temperature Shift HRSG (“HT HRSG”) is adapted from the original process simulation [2]. The primary purpose is to

reduce the syngas temperature between the two stages of shift reactors. The heat is used to raise the temperature of LT Steam and to generate additional steam.

The heat available from the syngas stream is modeled with Euler's Method to estimate the change in sensible enthalpy from 708°K to 473°K using an approximation of specific heat of the form $C_p = A + BT + CT^2 + DT^3 + ET^4$ [5]. The heat required to raise the temperature of the LT Steam from 455°K to 600°K and to raise the temperature of pressurized water (Pressurized Water #2, "P Water 2") at 288°K to 600°K are estimated from the difference in enthalpies of water at these two temperatures at 3.65 MPa, as provided by the NIST Chemistry WebBook, Thermophysical Properties of Fluid Systems, Isobaric properties for Water at a pressure of 3.65 MPa [6]. The quantity of LT Steam throughput is defined by the difference in the quantity of LT Steam and the LT Steam throughput of the PHT and Ref CP HRSG's – in other words, all LT Steam that is not diverted to the other two HRSG's is directed to the HT HRSG. The heat used for the LT Steam heating is estimated by dividing the heat requirement, discussed above, by 0.98, reflecting a heat transfer efficiency of 98%, and multiplying by the molar LT Steam throughput. The throughput of 288°K water is determined by dividing the remaining heat available by the heat required and multiplying the result by 0.98 to reflect a heat transfer efficiency of 98%.

In the model version with CCS and without Steam Reform, there is insufficient heat available in the HT HRSG to raise the temperature of all the LT Steam not diverted to the PHT HRSG. As such, in this model version, the Water Pump 2 is eliminated and excess

LT Steam is mixed with excess steam from the PHT HRSG and the HT HRSG for supplemental power generation, assuming gross thermal equilibrium is achieved between these three streams and assuming constant C_p .

Summary:

- Input stream(s): High Temperature Shift Output (“HT Shift Output”)
Low Temperature Shift HRSG Steam (“LT Steam”)
Pressurized Water #2 (“P Water 2”)
- Output stream(s): Low Temperature Shift Input (“LT Shift input”)
High Temperature Shift HRSG Steam (“HT Steam”)
- Reference: [2]

Low Temperature Shift. Modeling of the LT Shift is adapted directly from the original process simulation [2]. CO in the output stream is set to 25% of the CO in the HT Shift Input stream on a molar basis, based on the original process simulation. Output flow rates of CO₂, H₂ and H₂O are modeled from the input flow rates with adjustments to stoichiometrically balance changes in the CO flow rate.

Summary:

- Input stream(s): Low Temperature Shift Input (“LT Shift Input”)
- Output stream(s): Low Temperature Shift Output (“LT Shift Output”)
- Reference: [2]

Low Temperature Shift HRSG. Modeling of the Low Temperature Shift HRSG (“LT HRSG”) is adapted from the original gasification process simulation [2], in which it reduced the syngas temperature in preparation for the Pressure Swing Absorption system, to reduce the temperature of the LT Shift Output before compression to match the

pressure of the CO₂ scrubber, as defined in the original process simulation of that system [3, 4]. Heat from the syngas stream is used to raise steam at 455 °K from pressurized water at 288 °K (Pressurized Water #1, “P Water 1”).

The heat available from the syngas stream is modeled with Euler’s Method to estimate the change in sensible enthalpy from 494 °K to 297 °K using an approximation of specific heat of the form $C_p = A + BT + CT^2 + DT^3 + ET^4$ [5]. The heat required to raise the temperature of the pressurized water from 288 °K to 455 °K (including the heat of vaporization) is estimated from the difference in enthalpies of water at these two temperatures at 3.65 MPa, as provided by the NIST Chemistry WebBook, Thermophysical Properties of Fluid Systems, Isobaric properties for Water at a pressure of 3.65 MPa [6]. The quantity of water throughput is estimated by dividing the heat available by the heat required and multiplying the result by 0.98 to reflect a heat transfer efficiency of 98%.

Summary:

- Input stream(s): Low Temperature Shift Output (“LT Shift Output”)
Pressurized Water #1 (“P Water 1”)
- Output stream(s): Compressor #2 Input (“Comp 2 Input”)
Low Temperature Shift HRSG Steam (“LT Steam”)
- Reference: [2]

Compressor #2. Compressor #2 (“Comp 2”) is intended to raise the pressure of the syngas stream to match that of the input stream for the CO₂ capture system. The only changes to the syngas stream passing through the compressor are temperature and

pressure. The pressure change is defined by the output pressure of the syngas leaving the LT HRSG, as defined in the gasification process simulation [2], and the input pressure for the CO₂ capture system, as defined in the process simulation of that subsystem [3, 4].

The temperature change is estimated with the equation for adiabatic discharge temperature from the Chemical Engineering Handbook [3, 4, 8]:

$$T2_{Adiabatic} = T1 \times \left(\frac{P2}{P1} \right)^{(k-1)/k}$$

Where:

- T1 = the temperature (in Kelvin) of the input stream, Comp 2 Input;
- P1 = the pressure (in Pascals) of the input stream, Comp 2 Input;
- P2 = the pressure (in Pascals) of the output stream, defined in [3, 4];
- k = P1 × V1
- V1 = (nRT1) / P1
- n = number of moles per hour
- R = 8.314 [J mol⁻¹ K⁻¹]

Summary:

- Input Stream(s): Compressor #2 Input (“Comp 2 Input”)
- Output Stream(s): Compressor #2 Output (“Comp 2 Output”)
- Reference: [2-4, 8]

Carbon Capture Heat Exchanger. Modeling for the Carbon Capture Heat Exchanger (“CCHX”) is adapted from the original process simulation for the Carbon Capture subsystem [3, 4]. The CCHX cools syngas entering the CO₂ Scrubber against syngas exiting the scrubber. On the hot (CO₂ rich) side of the CCHX, the input temperature is equal to that of the syngas exiting Compressor #2 and the output temperature is defined by the CO₂ scrubber input temperature in the original process simulation of the Carbon Capture subsystem [3, 4]. On the cold side of the CCHX, the input temperature is

defined by the CO₂ scrubber output temperature and the output temperature is defined in proportion to the net temperature change from hot-side input to cold-side output in the original process simulation [3, 4]. Specifically, the cold-side output temperature is estimated as:

$$T_{CCHX_Cold_Out} = T_{Comp2Out} \times \left(\frac{T_{CCHX_Cold_Out,PS}}{T_{CCHX_Hot_In,PS}} \right)$$

Where:

$T_{CCHX_Cold_Out,PS}$ = The cold-side output T in the original simulation [3, 4];

$T_{CCHX_Hot_In,PS}$ = The hot-side input T in the original simulation [3, 4].

Summary:

- Input Stream(s): Compressor #2 Output (“Comp 2 Output”)
CO₂ Scrubber Output (“Scrub Output”)
- Output Stream(s): CO₂ Scrubber Input (“Scrub Input”)
Hydrogen Rich Fuel Gas (“H-Rich FG”)

CO₂ Capture. Modeling of the CO₂ Capture system is adapted from the original process simulation [3, 4]. Molar flows in the CO₂ Scrubber Outputs (“Scrub Out”) are modeled from the inputs with proportional reductions consistent with the original process simulation. For example, CO₂ in the Scrub Out is equal to 1% of CO₂ in the Scrub In, consistent with the original simulation.

Note that C₂H₆ and C₂H₄ were not present in the syngas of the original process simulation, and therefore that study did not provide a direct basis for modeling solvent selectivity for these compounds. It is assumed here that the selectivity for these higher hydrocarbons is equal to that of CH₄. This is only relevant in the model without Steam

Reform, as the reformer is assumed to convert these higher hydrocarbons, based on the original process simulation of that system [2].

Carbon capture rates are estimated from the difference in carbon content of the syngas streams on either side of the CO₂ Scrubber.

Solvent regeneration (including decompression, refrigeration, make-up, and compression), CO₂ compression, and supplemental power generation are assumed to be consistent with the original simulation, but are not modeled explicitly.

Gas Turbine Combined Cycle. The GTCC system model is based on the H-Class technology marketed by General Electric with minor modifications to accommodate hydrogen rich fuel gas, as described in the literature [9] [10]. From the technical modeling perspective adopted in this analysis, two key parameters are considered. First, the GTCC is assumed to be 60% efficient on a Lower Heating Value (“LHV”) basis, consistent with the literature on the H-class power system [9]. Therefore, Gross Power Generation from the GTCC (“GTCC Gross Gen”) is defined to be equal to 60% of the LHV energy content of the Heated FG entering the GTCC.

Second, steam is to be added to the H-Rich FG at a rate of 0.6 kg steam per dry kg of fuel to control firing temperatures in the GTCC combustor [10]. This humidification is assumed to be accomplished within the GTCC subsystem by mixing the Heated Fuel Gas (“HFG”) with the Humidification Steam (“H Steam”). Both streams are at equal pressure

and calculations to ensure that the steam does not condense upon mixing are described in the section characterizing the FGHX.

Summary:

- Input Stream(s): Heated Fuel Gas (“Heated FG”)
Humidification Steam (“Humid Steam”)
- Output Streams(s): Gross GTCC Generation (“GTCC Gross Gen”)

Net Generation. Net electricity generation is defined as equal to GTCC Gross Gen plus Supplemental Generation (“Sup Gen”) minus the plant’s parasitic load. Sup Gen is from three sources. The first two are power recovery turbines (“PRT’s”) directly upstream from the decompression flash tanks in the solvent regeneration portion of the Carbon Capture system. These PRT’s are assumed to be implemented as described in the original process simulation of the carbon capture system [3, 4]. Sup Gen from these turbines is scaled linearly from that in the original process simulation based on the molar flow of CO₂ in the Scrub In stream. An additional PRT is included in model versions with substantial excess steam generation from the PHT HRSG. The power potential of this Sup Gen Steam is estimated assuming adiabatic expansion to atmospheric pressure, based on the equations related to power generation from adiabatic expansion in [8], and assuming 40% efficient conversion to electricity.

Parasitic load is estimated from the three original process simulation studies: [1] for power requirements from the dryer and gasifier; [2] for power requirements from syngas conditioning; and [3, 4] for power requirements from the carbon capture system. These components include:

- From [1]:
 - Combustion Blower
 - Dryer fan
 - Other dryer
 - Pumps
 - Conveyers
 - Rotary feeder
 - Feed screw
 - Condensate pump
 - Ash handling
 - Wood handling
 - Nitrogen
 - Miscellaneous
- From [2]:
 - Syngas Compressor (4-stage compression after gas cleaning)
 - Water pump (originally titled “syncompr water pump”) - adapted here to pressurize water for the LT HRSG and HT HRSG
- From [3, 4]:
 - 3 CO₂ compressors for final compression (up to 100 bar)
 - 2 intermediate compressors
 - Recycle compressor
 - Solvent circulation pump

The power requirements for these various components are scaled linearly from those listed in the original studies. Scaling is based on wood throughput for the components from [1] and [2], and based on syngas throughput into the scrubber for components from [3, 4].

C2. Economic model characterization

The economic model consists of two parts: computation of capital costs and computation of operating and maintenance (“O&M”) costs. Both of these parts are derived from the economic models developed in the original design studies [1-4]. Direct costs, additional cost allocations, and all associated assumptions from these studies are directly incorporated into the current economic model.

Capital cost computation. Capital costs are adapted from the original design studies in a three step process: component capital costs are scaled to the level appropriate for the current modeling exercise; component capital costs are converted to year 2000 dollars with the CE Plant Cost Index; and capital allocations for indirect costs are added to the scaled component costs to develop the total capital requirement. Because the original design studies were developed at different scales, with different assumptions regarding indirect capital allocations, and in currencies from different years, capital costs are computed independently for the components modeled from each design study. These three resulting total capital requirements are then added together to provide the plant-wide total capital requirement.

A scaling factor approach is used to account for different component scales in capital cost estimation. According to this approach, capital costs are assumed to be proportional to the ratio of component scales raised to the power 0.7, or,

$$CCost_M = CCost_O \times \left(\frac{Scale_M}{Scale_O} \right)^{0.7}$$

Where “CCost” refers to the direct component capital cost, “Scale” refers to the component’s scale, and the subscripts “O” and “M” refer to the original and modeled values, respectively. Component throughput is generally used to define component scale; however the measure of throughput used differs across components. Component capital costs and the basis of scale are characterized in Table C1.

Capital allocations for indirect costs are added to the scaled component costs based on the assumptions in the original design studies. Assumptions regarding these cost allocations differ across the original design studies. Therefore, to maintain consistency with the original studies, indirect capital costs in the current model are computed independently for components from each design study. These cost allocations are defined in proportion to the component costs. Therefore, a global component cost multiplier is developed and applied to the total scaled costs of components modeled from each of the underlying studies. These multipliers are defined by dividing the total capital requirement by the total of component costs as published in each study. The resulting multipliers for the components from design studies [1, 2] and [3, 4] are ~1.53, ~3.78, and ~1.97, respectively.

Table C1
Scaled component capital costs (thousand year 2000 dollars)

Component descriptor	Original literature	Original cost (\$1,000)	Scale basis	Scaled component cost				
				BIGCC	BIGCC-CCS _{NR}	BIGCC-CCS _{R,SG}	BIGCC-CCS _{R,FG}	BIGCC-CCS _{R,SG,UD}
Gasifier ^a	[1]	\$22,000	Wood input	\$43,000	\$43,000	\$42,000	\$42,000	\$28,000
Comp 1 ^b	[2]	\$4,010	Syngas input	\$0	\$5,100	\$5,100	\$5,100	\$4,500
Reformer	[2]	\$930	Dry syngas input	\$0	\$0	\$1,600	\$1,800	\$1,400
FGHX	[2]	\$50	Heat rate	\$0	\$70	\$85	\$94	\$76
PHT HRSG	[2]	\$20	H2O input	\$0	\$16	\$35	\$31	\$32
CP HRSG	[2]	\$20	H2O input	\$0	\$0	\$16	\$22	\$15
HT Shift	[2]	\$60	Dry syngas input	\$0	\$66	\$96	\$106	\$86
Pump 2	[2]	\$30	H2O input	\$0	\$0	\$23	\$19	\$0
HT HRSG	[2]	\$30	Syngas input	\$0	\$31	\$45	\$50	\$0
LT Shift	[2]	\$50	Dry syngas input	\$0	\$66	\$85	\$94	\$76
LT HRSG	[2]	\$170	Syngas input	\$0	\$200	\$290	\$320	\$0
Pump 1	[2]	\$30	H2O input	\$0	\$46	\$64	\$71	\$0
Comp 2	[2]	\$60	Horsepower	\$0	\$68	\$72	\$80	\$65
CCHX	[2]	\$50	Heat rate	\$0	\$27	\$33	\$36	\$29
Scrubber ^c	[3]	\$8,870	Syngas input	\$0	\$7,200	\$9,000	\$10,000	\$8,100
Sup Gen	[3]	d	Power output	\$0	\$670	\$610	\$0	\$600
GTCC ^e			Power output	\$88,000	\$79,000	\$71,000	\$63,000	\$61,000
TCR ^f	[1]			\$66,000	\$66,000	\$64,000	\$64,000	\$43,000
TCR ^g	[2]			\$0	\$21,000	\$28,000	\$29,000	\$25,000
TCR ^h	[3]			\$0	\$16,000	\$19,000	\$20,000	\$170
TCR ⁱ				\$88,000	\$79,000	\$71,000	\$63,000	\$61,000
TCR Total				\$153,000	\$181,000	\$183,000	\$176,000	\$147,000
Specific TCR				\$1,026	\$1,469	\$1,698	\$1,929	\$1,618

Table C1 --- Continued ---

^aIncludes capital costs for all components in the original design study under the headings "Fuel handling", "Gasifier / combustor", "Product gas cleanup", and "Misc." minus those for the product gas HRSG in versions BIGCC and BIGCC-CCSNR and minus those for both the product gas HRSG and the tar cracker in versions with steam reform, as the design study [Mann] concluded that all tars should be converted to lower hydrocarbons in the steam reformer; The original cost including the tar cracker in the versions without steam reform is \$23 M.

^bIncludes the costs of compressor, intercoolers, and the compressed syngas re-heater.

^cIncludes costs associated with the CO₂ absorption column, the absorption column packing, power recovery turbines 1 and 2, the slump tank, flash tanks 1, 2, and 3, the solvent circulation pump, compressors 1 and 2 for CO₂, re Fridgeration, and the three CO₂ product gas compressors.

^dPlotting costs for the 6 power recovery turbines in the original design study [Doctor] suggests a scaling factor of 0.4. The power function $C_{\text{cost}_{\text{SupGen}}} = 21216 \times \text{kW}_{\text{output}}^{0.4}$ was used.

^eA fixed specific cost of 550 \$/KW is used for estimating the total installed capital cost of the GTCC.

^fTCR for components modeled from [1]

^gTCR for components modeled from [2]

^hTCR for components modeled from [3]

ⁱTCR for GTCC

Note: Values presented may not compute to TCR due to rounding.

Operating and maintenance costs. Operating and maintenance costs (“O&M”) have three basic components: fuel; fixed O&M; and non-fuel variable O&M. Fuel costs are modeled by converting an assumed delivered fuel price of \$50 per dry ton biomass to cents per kilowatt hour thermal biomass input, assuming a higher heating value of 20 MJ/kg, and dividing the converted fuel cost by the net plant efficiency to give fuel costs on an energy output basis. Fixed and non-fuel variable O&M are adapted directly from the drivers listed in the underlying design studies [1-4].

O&M costs adapted from [2] are assumed to account for those costs associated with the gasification, syngas conditioning, and GTCC subsystems. Of those adapted, only those under the headings water and sand / ash disposal are treated explicitly as non-fuel variable O&M. These cost drivers are given on a specific basis in the original design study. As water costs are given on a per bone dry ton wood input per day basis in the original design study, the published cost rate is multiplied by the modeled wood feed rate and converted to an annual cost assuming a 0.8 capacity factor. Sand / ash disposal costs are given as a dollars per hour rate; therefore, the published cost is linearly scaled by multiplying the originally published costs by the ratio of wood feed capacities (modeled feed rate / published feed rate) and then converted to a total annual cost assuming a capacity factor of 0.8.

O&M costs adapted from [2] that are not explicitly treated as variable include labor, maintenance, insurance / local taxes, royalties, and other operating costs. Labor costs are adapted by modifying the numbers of operators and foreman assumed for each model

version. The number of operators is increased from 8 to 10 and the number of foremen is increased from 2 to 3 in model versions with CCS. The numbers of operators and foremen are decreased to 5 and 2, respectively, for the version without CCS. All models assume 1 supervisor, consistent with the original study. Annual costs for operators, foremen, and supervisors are taken directly from the original study and assumed to be \$28,700, \$30,500, and \$39,300, respectively.

Annual O&M costs adapted from [2] for maintenance, insurance / local taxes, royalties, and other operating costs are all linearly scaled based on the ratio of wood feed rates. No adaptation of O&M costs is performed to remove those associated with downstream equipment (e.g., the pressure swing absorption system).

Annual O&M costs adapted from [3, 4] to account for those associated with the CCS system include consumable material (catalyst and misc.), ash / sorbent material disposal, plant labor (operating labor and supervision / support), maintenance, insurance / local taxes, and other. Costs for consumable material, ash / sorbent material disposal, and plant labor are all adapted in two ways. The incremental cost of the CCS subsystem is captured by subtracting the published values for the base case (coal IGCC without CCS) from the published values for case 1 (coal IGCC with CCS). The resulting costs are divided by three to account for the three CCS trains modeled in the original design study compared with the single train modeled here. Note, however, that there is no difference in the originally published costs between the base case and case 1 for ash / sorbent material disposal or plant labor. Also, the difference in consumable material costs are not

adapted to prevent double counting of materials associated with, e.g., the shift reactor and associated catalyst, which are implicitly included in these O&M cost estimates in the original design study but captured for the purposes of the current model in the costs adapted from [2].

Annual O&M costs adapted from [3, 4] for maintenance, insurance / local taxes, and other are all defined as a fraction of direct costs. These costs are similarly modeled here by multiplying the published fractions of direct costs (2.7% and 0.9%, respectively) by the total cost of components modeled from [3, 4], as described above. Because these costs are defined relative to the component costs, there should be no double-counting with O&M costs of the same type adapted from [2].

The total annual O&M figure, obtained by summing the annual costs listed thus far [dollars per year] is divided by the product of net generation capacity [kilowatts] and an assumed capacity factor of 0.8 to yield O&M costs on an annual energy output basis [\$/kW-yr], which is then converted to cents per kilowatt hour. Resulting in energy output specific O&M costs for all model versions are listed in Table 3.2. Note that O&M costs are not converted to year 2000 dollars.

C3. Process modeling flows

Process flows between the subsystem components in each of the model versions discussed in this thesis are characterized in Table C2. Labels for each flow stream are consistent with those used in Section C1. A flow stream that appears to be empty in the table for a particular model version should be interpreted as non-existent in that version because the associated subsystem components are not included.

Table C2. Process modeling flows

Stream	Wood Input	Clean Syngas	Comp Syngas	Cond Steam	Reformer Syngas	Reformed Syngas	Cool Ref Syngas	HT Shift Input
Wood (dry kg/hr)	80221	0	0	0	0	0	0	0
CO (kmol/hr)		1270	0	0	0	0	0	0
CO ₂ (kmol/hr)		299	0	0	0	0	0	0
H ₂ (kmol/hr)		427	0	0	0	0	0	0
H ₂ O (kmol/hr)		373	0	0	0	0	0	0
N ₂ (kmol/hr)		0	0	0	0	0	0	0
Ar (kmol/hr)		0	0	0	0	0	0	0
CH ₄ (kmol/hr)		422	0	0	0	0	0	0
NH ₃ (kmol/hr)		0	0	0	0	0	0	0
H ₂ S (kmol/hr)		0	0	0	0	0	0	0
H ₂ CN (kmol/hr)		0	0	0	0	0	0	0
O ₂ (kmol/hr)		0	0	0	0	0	0	0
COS (kmol/hr)		0	0	0	0	0	0	0
SO ₂ (kmol/hr)		0	0	0	0	0	0	0
NO (kmol/hr)		0	0	0	0	0	0	0
C ₂ H ₆ (kmol/hr)		25	0	0	0	0	0	0
C ₂ H ₄ (kmol/hr)		154	0	0	0	0	0	0
C ₂ H ₂ (kmol/hr)		0	0	0	0	0	0	0
T (K)		0	0	0	0	0	0	0
P (MPa)		0.00	0.00	0.00	0.00	0.00	0.00	0.00

BIGCC

Table C2. ---Continued---

Stream	HT Shift Output	LT Shift Input	LT Shift Output	Comp2 Input	Comp2 Output	Scrub Input	Scrub Output	H-Rich FG
Wood (dry kg/hr)		0	0	0	0	0	0	0
CO (kmol/hr)		0	0	0	0	0	0	0
CO2 (kmol/hr)		0	0	0	0	0	0	0
H2 (kmol/hr)		0	0	0	0	0	0	0
H2O (kmol/hr)		0	0	0	0	0	0	0
N2 (kmol/hr)		0	0	0	0	0	0	0
Ar (kmol/hr)		0	0	0	0	0	0	0
CH4 (kmol/hr)		0	0	0	0	0	0	0
NH3 (kmol/hr)		0	0	0	0	0	0	0
H2S (kmol/hr)		0	0	0	0	0	0	0
HCCN (kmol/hr)		0	0	0	0	0	0	0
O2 (kmol/hr)		0	0	0	0	0	0	0
COS (kmol/hr)		0	0	0	0	0	0	0
SO2 (kmol/hr)		0	0	0	0	0	0	0
NO (kmol/hr)		0	0	0	0	0	0	0
C2H6 (kmol/hr)		0	0	0	0	0	0	0
C2H4 (kmol/hr)		0	0	0	0	0	0	0
C2H2 (kmol/hr)		0	0	0	0	0	0	0
T (K)		0	0	0	0	0	0	0
P (MPa)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

BIGCC

Table C2. ---Continued---

Stream	Humid		Reformer			CP Exhaust	PWater1	LT Steam
	Heated FG	Steam	Mixed FG	Comb	CP			
Wood (dry kg/hr)	0	0	0	0	0	0	0	0
CO (kmol/hr)	0	0	1270	0	0	0	0	0
CO2 (kmol/hr)	0	0	299	0	0	0	0	0
H2 (kmol/hr)	0	0	427	0	0	0	0	0
H2O (kmol/hr)	0	0	373	0	0	0	0	0
N2 (kmol/hr)	0	0	0	0	0	0	0	0
Ar (kmol/hr)	0	0	0	0	0	0	0	0
CH4 (kmol/hr)	0	0	422	0	0	0	0	0
NH3 (kmol/hr)	0	0	0	0	0	0	0	0
H2S (kmol/hr)	0	0	0	0	0	0	0	0
HCCN (kmol/hr)	0	0	0	0	0	0	0	0
O2 (kmol/hr)	0	0	0	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0	0	0	0
SO2 (kmol/hr)	0	0	0	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0	0	0	0
C2H6 (kmol/hr)	0	0	25	0	0	0	0	0
C2H4 (kmol/hr)	0	0	154	0	0	0	0	0
C2H2 (kmol/hr)	0	0	0	0	0	0	0	0
T (K)	0	0	0	0	0	0	0	0
P (MPa)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

BIGCC

Table C2. ---Continued---

Stream	CP Steam	PHT Steam	PWater2	HT Steam	Sup Gen Steam
Wood (dry kg/hr)	0	0	0	0	0
CO (kmol/hr)	0	0	0	0	0
CO2 (kmol/hr)	0	0	0	0	0
H2 (kmol/hr)	0	0	0	0	0
H2O (kmol/hr)	0	0	0	0	0
N2 (kmol/hr)	0	0	0	0	0
Ar (kmol/hr)	0	0	0	0	0
CH4 (kmol/hr)	0	0	0	0	0
NH3 (kmol/hr)	0	0	0	0	0
H2S (kmol/hr)	0	0	0	0	0
HCN (kmol/hr)	0	0	0	0	0
O2 (kmol/hr)	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0
SO2 (kmol/hr)	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0
C2H6 (kmol/hr)	0	0	0	0	0
C2H4 (kmol/hr)	0	0	0	0	0
C2H2 (kmol/hr)	0	0	0	0	0
T (K)	0	0	0	0	0
P (MPa)	0.00	0.00	0.00	0.00	0.00

BIGCC

Table C2. ---Continued---

Stream	Wood Input	Clean Syngas	Comp Syngas	Cond Steam	Reformer Syngas	Reformed Syngas	Cool Ref Syngas	HT Shift Input
Wood (kg/hr)	80221	0	0	0	0	0	0	0
CO (kmol/hr)		1270	1270	0	0	0	0	1270
CO2 (kmol/hr)		299	299	0	0	0	0	299
H2 (kmol/hr)		427	427	0	0	0	0	427
H2O (kmol/hr)		373	373	1769	0	0	0	373
N2 (kmol/hr)		0	0	0	0	0	0	0
Ar (kmol/hr)		0	0	0	0	0	0	0
CH4 (kmol/hr)		422	422	0	0	0	0	422
NH3 (kmol/hr)		0	0	0	0	0	0	0
H2S (kmol/hr)		0	0	0	0	0	0	0
HCN (kmol/hr)		0	0	0	0	0	0	0
O2 (kmol/hr)		0	0	0	0	0	0	0
COS (kmol/hr)		0	0	0	0	0	0	0
SO2 (kmol/hr)		0	0	0	0	0	0	0
NO (kmol/hr)		0	0	0	0	0	0	0
C2H6 (kmol/hr)		25	25	0	0	0	0	25
C2H4 (kmol/hr)		154	154	0	0	0	0	154
C2H2 (kmol/hr)		0	0	0	0	0	0	0
T (K)		0	1073	628	0	0	0	647
P (MPa)		0.00	3.65	3.65	0.00	0.00	0.00	3.65

BIGCC-CCS_{NR}

Table C2. ---Continued---

Stream	HT Shift Output	LT Shift Input	LT Shift Output	Comp2 Input	Comp2 Output	Scrub Input	Scrub Output	H-Rich FG
Wood (kg/hr)	0	0	0	0	0	0	0	0
CO (kmol/hr)	381	381	95	95	95	95	94	94
CO ₂ (kmol/hr)	1188	1188	1474	1474	1474	1474	15	15
H ₂ (kmol/hr)	1316	1316	1602	1602	1602	1602	1590	1590
H ₂ O (kmol/hr)	1254	1254	968	0	0	0	0	0
N ₂ (kmol/hr)	0	0	0	0	0	0	0	0
Ar (kmol/hr)	0	0	0	0	0	0	0	0
CH ₄ (kmol/hr)	422	422	422	422	422	422	401	401
NH ₃ (kmol/hr)	0	0	0	0	0	0	0	0
H ₂ S (kmol/hr)	0	0	0	0	0	0	0	0
HCN (kmol/hr)	0	0	0	0	0	0	0	0
O ₂ (kmol/hr)	0	0	0	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0	0	0	0
SO ₂ (kmol/hr)	0	0	0	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0	0	0	0
C ₂ H ₆ (kmol/hr)	25	25	25	25	25	25	24	24
C ₂ H ₄ (kmol/hr)	154	154	154	154	154	154	146	146
C ₂ H ₂ (kmol/hr)	0	0	0	0	0	0	0	0
T (K)	708	473	494	297	364	286	272	292
P (MPa)	3.10	3.10	2.64	2.51	3.08	3.08	0.00	3.04

BIGCC-CCS_{NR}

Table C2. ---Continued---

Stream	Humid		Reformer			CP Exhaust	PWater1	LT Steam
	Heated FG	Steam	Mixed FG	Comb	CP			
Wood (kg/hr)	0	0	0	0	0	0	0	0
CO (kmol/hr)	94	0	94	0	0	0	0	0
CO2 (kmol/hr)	15	0	15	0	0	0	0	0
H2 (kmol/hr)	1590	0	1590	0	0	0	0	0
H2O (kmol/hr)	0	106	0	0	0	0	2822	12760
N2 (kmol/hr)	0	0	0	0	0	0	0	0
Ar (kmol/hr)	0	0	0	0	0	0	0	0
CH4 (kmol/hr)	401	0	401	0	0	0	0	0
NH3 (kmol/hr)	0	0	0	0	0	0	0	0
H2S (kmol/hr)	0	0	0	0	0	0	0	0
HCN (kmol/hr)	0	0	0	0	0	0	0	0
O2 (kmol/hr)	0	0	0	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0	0	0	0
SO2 (kmol/hr)	0	0	0	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0	0	0	0
C2H6 (kmol/hr)	24	0	24	0	0	0	0	0
C2H4 (kmol/hr)	146	0	146	0	0	0	0	0
C2H2 (kmol/hr)	0	0	0	0	0	0	0	0
T (K)	372	778	395	0	0	0	288	455
P (MPa)	3.04	3.04	3.04	0.00	0.00	0.00	3.65	3.65

BIGCC-CCS_{NR}

Table C2. ---Continued---

Stream	CP Steam	PHT Steam	PWater2	HT Steam	Sup Gen Steam
Wood (kg/hr)	0	0	0	0	0
CO (kmol/hr)	0	0	0	0	0
CO2 (kmol/hr)	0	0	0	0	0
H2 (kmol/hr)	0	0	0	0	0
H2O (kmol/hr)	0	829	0	1183	946
N2 (kmol/hr)	0	0	0	0	0
Ar (kmol/hr)	0	0	0	0	0
CH4 (kmol/hr)	0	0	0	0	0
NH3 (kmol/hr)	0	0	0	0	0
H2S (kmol/hr)	0	0	0	0	0
HCN (kmol/hr)	0	0	0	0	0
O2 (kmol/hr)	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0
SO2 (kmol/hr)	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0
C2H6 (kmol/hr)	0	0	0	0	0
C2H4 (kmol/hr)	0	0	0	0	0
C2H2 (kmol/hr)	0	0	0	0	0
T (K)	0	811	288	529	586
P (MPa)	0.00	3.65	3.65	3.65	3.65

BIGCC-CCS_{NR}

Table C2. ---Continued---

Stream	Wood Input	Clean Syngas	Comp Syngas	Cond Steam	Reformer Syngas	Reformed Syngas	Cool Ref Syngas	HT Shift Input
Wood (kg/hr)	80221	0	0	0	0	0	0	0
CO (kmol/hr)		1270	1270	0	1094	856	856	856
CO2 (kmol/hr)		299	299	0	258	1019	1019	1019
H2 (kmol/hr)		427	427	0	368	2411	2411	2411
H2O (kmol/hr)		373	373	4657	4979	3694	3694	3694
N2 (kmol/hr)		0	0	0	0	0	0	0
Ar (kmol/hr)		0	0	0	0	0	0	0
CH4 (kmol/hr)		422	422	0	364	149	149	149
NH3 (kmol/hr)		0	0	0	0	0	0	0
H2S (kmol/hr)		0	0	0	0	0	0	0
HCN (kmol/hr)		0	0	0	0	0	0	0
O2 (kmol/hr)		0	0	0	0	0	0	0
COS (kmol/hr)		0	0	0	0	0	0	0
SO2 (kmol/hr)		0	0	0	0	0	0	0
NO (kmol/hr)		0	0	0	0	0	0	0
C2H6 (kmol/hr)		25	25	0	21	0	0	0
C2H4 (kmol/hr)		154	154	0	133	0	0	0
C2H2 (kmol/hr)		0	0	0	0	0	0	0
T (K)		0	1073	728	1073	1123	1098	643
P (MPa)		0.00	3.65	3.65	3.65	3.47	3.47	3.47

BIGCC-CCS_{R,SG}

Table C2. ---Continued---

Stream	HT Shift Output	LT Shift Input	LT Shift Output	Comp2 Input	Comp2 Output	Scrub Input	Scrub Output	H-Rich FG
Wood (kg/hr)	0	0	0	0	0	0	0	0
CO (kmol/hr)	257	257	64	64	64	64	64	64
CO2 (kmol/hr)	1618	1618	1811	1811	1811	1811	18	18
H2 (kmol/hr)	3010	3010	3203	3203	3203	3203	3180	3180
H2O (kmol/hr)	3095	3095	2903	0	0	0	0	0
N2 (kmol/hr)	0	0	0	0	0	0	0	0
Ar (kmol/hr)	0	0	0	0	0	0	0	0
CH4 (kmol/hr)	149	149	149	149	149	149	142	142
NH3 (kmol/hr)	0	0	0	0	0	0	0	0
H2S (kmol/hr)	0	0	0	0	0	0	0	0
HCN (kmol/hr)	0	0	0	0	0	0	0	0
O2 (kmol/hr)	0	0	0	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0	0	0	0
SO2 (kmol/hr)	0	0	0	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0	0	0	0
C2H6 (kmol/hr)	0	0	0	0	0	0	0	0
C2H4 (kmol/hr)	0	0	0	0	0	0	0	0
C2H2 (kmol/hr)	0	0	0	0	0	0	0	0
T (K)	708	473	494	297	364	286	272	292
P (MPa)	2.95	2.95	2.51	2.51	3.08	3.08	0.00	3.04

Table C2. ---Continued---

Stream	Humid		Mixed FG	Reformer		CP Exhaust	PWater1	LT Steam
	Heated FG	Steam		Comb	CP			
Wood (kg/hr)	0	0	0	0	0	0	0	0
CO (kmol/hr)	64	0	64	176	0	0	0	0
CO2 (kmol/hr)	18	0	18	41	325	325	0	0
H2 (kmol/hr)	3180	0	3180	59	0	0	0	0
H2O (kmol/hr)	0	209	0	52	280	280	4347	4347
N2 (kmol/hr)	0	0	0	0	1166	1166	0	0
Ar (kmol/hr)	0	0	0	0	0	0	0	0
CH4 (kmol/hr)	142	0	142	58	0	0	0	0
NH3 (kmol/hr)	0	0	0	0	0	0	0	0
H2S (kmol/hr)	0	0	0	0	0	0	0	0
HCN (kmol/hr)	0	0	0	0	0	0	0	0
O2 (kmol/hr)	0	0	0	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0	0	0	0
SO2 (kmol/hr)	0	0	0	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0	0	0	0
C2H6 (kmol/hr)	0	0	0	3	0	0	0	0
C2H4 (kmol/hr)	0	0	0	21	0	0	0	0
C2H2 (kmol/hr)	0	0	0	0	0	0	0	0
T (K)	372	778	402	1073	1224	511	288	455
P (MPa)	3.04	3.04	3.04	3.65	0.10	0.10	3.65	3.65

BIGCC-CCS_{R,SG}

Table C2. ---Continued---

Stream	CP Steam	PHT Steam	PWater2	HT Steam	Sup Gen Steam
Wood (kg/hr)	0	0	0	0	0
CO (kmol/hr)	0	0	0	0	0
CO2 (kmol/hr)	0	0	0	0	0
H2 (kmol/hr)	0	0	0	0	0
H2O (kmol/hr)	988	2730	892	1521	437
N2 (kmol/hr)	0	0	0	0	0
Ar (kmol/hr)	0	0	0	0	0
CH4 (kmol/hr)	0	0	0	0	0
NH3 (kmol/hr)	0	0	0	0	0
H2S (kmol/hr)	0	0	0	0	0
HCN (kmol/hr)	0	0	0	0	0
O2 (kmol/hr)	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0
SO2 (kmol/hr)	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0
C2H6 (kmol/hr)	0	0	0	0	0
C2H4 (kmol/hr)	0	0	0	0	0
C2H2 (kmol/hr)	0	0	0	0	0
T (K)	811	811	288	529	728
P (MPa)	3.65	3.65	3.65	3.65	3.65

BIGCC-CCSR,SG

Table C2. ---Continued---

Stream	Wood Input	Clean Syngas	Comp Syngas	Cond Steam	Reformer Syngas	Reformed Syngas	Cool Ref Syngas	HT Shift Input
Wood (kg/hr)	80221	0	0	0	0	0	0	0
CO (kmol/hr)		1270	1270	0	1270	993	993	993
CO2 (kmol/hr)		299	299	0	299	1183	1183	1183
H2 (kmol/hr)		427	427	0	427	2799	2799	2799
H2O (kmol/hr)		373	373	5405	5778	4287	4287	4287
N2 (kmol/hr)		0	0	0	0	0	0	0
Ar (kmol/hr)		0	0	0	0	0	0	0
CH4 (kmol/hr)		422	422	0	422	173	173	173
NH3 (kmol/hr)		0	0	0	0	0	0	0
H2S (kmol/hr)		0	0	0	0	0	0	0
HCN (kmol/hr)		0	0	0	0	0	0	0
O2 (kmol/hr)		0	0	0	0	0	0	0
COS (kmol/hr)		0	0	0	0	0	0	0
SO2 (kmol/hr)		0	0	0	0	0	0	0
NO (kmol/hr)		0	0	0	0	0	0	0
C2H6 (kmol/hr)		25	25	0	25	0	0	0
C2H4 (kmol/hr)		154	154	0	154	0	0	0
C2H2 (kmol/hr)		0	0	0	0	0	0	0
T (K)		0	1073	711	1073	1123	978	643
P (MPa)		0.00	3.65	3.65	3.65	3.47	3.47	3.47

BIGCC-CCS_{R,FG}

Table C2. ---Continued---

Stream	HT Shift Output	LT Shift Input	LT Shift Output	Comp2 Input	Comp2 Output	Scrub Input	Scrub Output	H-Rich FG
Wood (kg/hr)	0	0	0	0	0	0	0	0
CO (kmol/hr)	298	298	74	74	74	74	74	74
CO2 (kmol/hr)	1878	1878	2102	2102	2102	2102	21	21
H2 (kmol/hr)	3494	3494	3717	3717	3717	3717	3690	3690
H2O (kmol/hr)	3592	3592	3369	0	0	0	0	0
N2 (kmol/hr)	0	0	0	0	0	0	0	0
Ar (kmol/hr)	0	0	0	0	0	0	0	0
CH4 (kmol/hr)	173	173	173	173	173	173	164	164
NH3 (kmol/hr)	0	0	0	0	0	0	0	0
H2S (kmol/hr)	0	0	0	0	0	0	0	0
HCN (kmol/hr)	0	0	0	0	0	0	0	0
O2 (kmol/hr)	0	0	0	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0	0	0	0
SO2 (kmol/hr)	0	0	0	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0	0	0	0
C2H6 (kmol/hr)	0	0	0	0	0	0	0	0
C2H4 (kmol/hr)	0	0	0	0	0	0	0	0
C2H2 (kmol/hr)	0	0	0	0	0	0	0	0
T (K)	708	473	494	297	364	286	272	292
P (MPa)	2.95	2.95	2.51	2.51	3.08	3.08	0.00	3.04

Table C2. ---Continued---

Stream	Humid		Reformer		CP	CP Exhaust	PWater1	LT Steam
	Heated FG	Steam	Mixed FG	Comb				
Wood (kg/hr)	0	0	0	0	0	0	0	0
CO (kmol/hr)	74	0	56	18	0	0	0	0
CO2 (kmol/hr)	21	0	16	5	62	62	0	0
H2 (kmol/hr)	3690	0	2812	878	0	0	0	0
H2O (kmol/hr)	0	187	0	0	957	957	5116	5116
N2 (kmol/hr)	0	0	0	0	1979	1979	0	0
Ar (kmol/hr)	0	0	0	0	0	0	0	0
CH4 (kmol/hr)	164	0	125	39	0	0	0	0
NH3 (kmol/hr)	0	0	0	0	0	0	0	0
H2S (kmol/hr)	0	0	0	0	0	0	0	0
HCN (kmol/hr)	0	0	0	0	0	0	0	0
O2 (kmol/hr)	0	0	0	0	0	0	0	0
COS (kmol/hr)	0	0	0	0	0	0	0	0
SO2 (kmol/hr)	0	0	0	0	0	0	0	0
NO (kmol/hr)	0	0	0	0	0	0	0	0
C2H6 (kmol/hr)	0	0	0	0	0	0	0	0
C2H4 (kmol/hr)	0	0	0	0	0	0	0	0
C2H2 (kmol/hr)	0	0	0	0	0	0	0	0
T (K)	798	778	749	798	1224	511	288	455
P (MPa)	3.04	3.04	3.04	3.04	0.10	0.10	3.65	3.65

Table C2. ---Continued---

Stream	CP Steam	PHT Steam	PWater2	HT Steam	Sup Gen Steam	
Wood (kg/hr)	0	0	0	0	0	
CO (kmol/hr)	0	0	0	0	0	
CO2 (kmol/hr)	0	0	0	0	0	
H2 (kmol/hr)	0	0	0	0	0	
H2O (kmol/hr)	1435	2189	490	1982	12	
N2 (kmol/hr)	0	0	0	0	0	
Ar (kmol/hr)	0	0	0	0	0	
BIGCC-CCS _{R,FG}	CH4 (kmol/hr)	0	0	0	0	
	NH3 (kmol/hr)	0	0	0	0	
	H2S (kmol/hr)	0	0	0	0	
	HCN (kmol/hr)	0	0	0	0	
	O2 (kmol/hr)	0	0	0	0	
	COS (kmol/hr)	0	0	0	0	
	SO2 (kmol/hr)	0	0	0	0	
	NO (kmol/hr)	0	0	0	0	
	C2H6 (kmol/hr)	0	0	0	0	
	C2H4 (kmol/hr)	0	0	0	0	
	C2H2 (kmol/hr)	0	0	0	0	
	T (K)	811	811	288	529	711
	P (MPa)	3.65	3.65	3.65	3.65	3.65

References

Appendix C

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Appendix D

Biofuels model documentation

Appendix D

Bio-fuel Model Documentation

This appendix is divided into three sections: Section D1 characterizes the engineering portion of the bio-fuels model; Section D2 characterizes the economic portion of the bio-fuels model; Section D3 provides model data in tabular form. The characterizations in both sections include descriptions of the computations, data sources, and the theoretical basis. Note that the models characterized in this appendix are strongly tied to the originally published design studies [1], [2] and [3], to an even greater extent than the BIGCC-CCS model characterized in Appendix C. This is because CCS integration affects only relatively minor components of the bio-fuels production systems. The unaffected balance of plants are assumed to be exactly as characterized in the original design studies [1-3].

For each of the two lingo-cellulosic bio-ethanol production systems modeled (wood-based and corn stover-based) three model versions are developed: a base-case with no CCS; a version that incorporates CO₂ capture from fermentation off-gasses; and a version that incorporates CO₂ capture from both fermentation off-gasses and post combustion capture (PCC) from combustor flue gases. Modeling of the base case is limited to adapting results from the original design studies to enable consistent comparisons with the model versions incorporating CCS. Electricity requirements for CCS and CO₂ compression are assumed to be met by modifying the net electricity generation. As both of the originally-published designs for bio-ethanol production include combustion of

waste biomass for electricity generation [1, 2], heat requirements for CCS are assumed to be met by diverting a portion of this waste biomass, with proportional reductions in electricity generation. Incremental electricity requirements are modeled by adjusting the quantity of net electricity imports / exports.

The original design study of Fischer Tropsch liquids production (“FT”) from biomass includes three model versions with pre-combustion separation (PCS) of CO₂ from the syngas upstream from the FT reactors to explore the trade-offs between increased cost, increased C₅₊ selectivity and increased conversion efficiency in the reactors [3]. These three versions (numbered 37, 38, and 39 in the original study) are adapted to the current model and modified to incorporate compression and pipeline transport of this separated CO₂ for geologic storage—which was not included in the original design study [3].

Incremental electricity requirements are modeled by adjusting net electricity imports / exports. The three model versions from the original design study with the lowest fuel production costs and without CO₂ separation (numbered 21, 22, and 40 in the original study) are also adapted to the current model to provide non-CCS baseline systems [3].

D1. Bio-fuels engineering model.

The biofuels production model is divided into four segments: biomass feed; fermentation off-gas; biomass gasification / combustion; and production. The underlying data for each segment is published differently in the original design studies. Therefore, the published

data is converted into a common set of parameters to enable consistent modeling. The model parameters, their derivation from the published data, and the associated modeling computations are characterized for each of the model segments described below.

Biomass feed. The current model includes parameters for biomass feed rates in unites of total dry mass [T / hr], carbon mass [TC / hr], and HHV energy throughput [MW]. Feed rates are specified on mass and HHV energy bases in [2] and [3], but only on a mass basis in [1]. A HHV of 20 MJ / kg, which appears appropriate for the yellow poplar feedstock assumed in [1], is used to convert the mass feed rate to an HHV energy basis. Wood feed is assumed to be 50% carbon on a dry mass basis; corn stover is assumed to be 46.6% carbon on a dry mass basis, which is an average of the sample data published in the U.S. Department of Energy's Biomass Feedstock Composition and Property Database for corn stover fuels [4].

Fermentation off-gases. CO₂ is a natural byproduct of fermentation, generally produced in equal molar proportions to ethanol [1, 2, 5]. In the original design studies these off-gases from fermentation, which are primarily CO₂ (97% and 98% on a mass basis according to [2] and [1], respectively), are vented to the atmosphere. 100% of this CO₂ is assumed to be captured and compressed for pipeline transport and geologic storage in model versions with CCS.

The throughput of this stream is equal to that published for stover-based ethanol production systems in [2]. For wood-based ethanol production, the throughput of this stream is increased from the published amount in proportion to the assumed increase in bio-fuel production rate. This assumed increase in production is based on the expectation published in the original design study that ethanol yields should increase from 68 gallons per dry ton in the base case (published in 1999) to 81 gallons per dry ton by 2005. The effects of this increased production rate are modeled assuming: (i) fermentation off-gas rates are proportional to ethanol production rates; (ii) the additional energy embodied in increased ethanol production is subtracted from boiler energy input; (iii) the carbon content of the boiler exhaust is proportional to the boiler energy input; and (iv) the increased production rate does not increase the plant's parasitic load.

Fermentation is not used in FT production, so the throughput of this stream is zero in the FT production systems modeled.

Biomass gasification / combustion. Biomass gasification / combustion is modeled only to the extent required to understand the quantity of CO₂ that may be captured and the effects of CO₂ capture and compression on electricity generation.

For bio-ethanol production systems CCS is modeled assuming 90% effective post combustion capture of CO₂ from boiler exhaust streams. For stover-based production the quantity of CO₂ captured is equal to 90% of that in the published exhaust stream [2].

Gross electricity generation is reduced to reflect the thermal energy requirement for PCS, which is assumed to be 3.3 GJth per TCO₂ [6]. 3.3 is divided by 0.98—reflecting an assumed 98% heat transfer efficiency—multiplied by the quantity of CO₂ captured and converted from the resulting units (GJth per hour) to MWth. The resulting thermal energy requirement is subtracted from the energy content of the combustor input available for electricity generation. The reduced combustor energy input is then multiplied by a net electricity conversion efficiency of 15% (HHV) (derived by dividing the published electricity generation by the published combustor energy input and consistent with the published combustor conversion efficiency in [1]) to estimate the system's gross electricity generation. 0.33 GJe per TCO₂ is multiplied by the quantity of CO₂ captured, converted to MW_e, and added to the system's parasitic load to account for the electricity required for PCS capture [6]. The parasitic load associated with CO₂ compression is estimated assuming five stage compression to 7.38 MPa followed by a pump to boost the pressure to 15 MPa based on the equations described in [7]. The results are consistent with the electricity requirement of 0.4 GJe per TCO₂ described in [6].

Modeling computations for the gasification / combustion segment are similar for wood-based production system except that both the energy content of the combustor input and the quantity of the resulting exhaust stream are reduced to reflect the increased ethanol yield. Specifically, the fraction of biomass feed energy embodied in the additional ethanol yield is subtracted from the fraction of feed energy embodied in the published combustor input stream. The resulting fraction of combustor input energy is multiplied

by the biomass feed rate (energy basis) to yield the modified combustor input energy. The modified combustor input energy is further reduced to reflect the thermal energy requirements for CCS and multiplied by the published 15% generation efficiency to define gross generation, as described above. The parasitic load is increased, as described above, to account for electricity requirements for PCS capture and compression for pipeline transport.

For FT systems, CCS is modeled in the original design study with a glycol-based CO₂ scrubber (PCS) directly upstream from the FT reactor [3]. The published rationale underlying the originally modeled CO₂ separation is to concentrate the FT reactants and reduce the scale of downstream equipment (including the FT reactors) [3]. Therefore, the only modification made in adapting the originally published results is to incorporate CO₂ compression for pipeline transport and account for the resulting negative carbon emissions. The quantity of CO₂ for compression is equal to the quantity separated in the originally published study. This quantity is multiplied by 0.4 GJe per TCO₂, converted to MW_e and added to the system's parasitic load.

Production. Bio-fuels production, net electricity generation, and net CO₂ emissions are all accounted for in the production segment of the model. Bio-fuels production rates are provided on a mass basis in the original design studies [1-3]. These production rates are converted to a HHV energy basis (MW_{bio-fuels}) with the HHV's provided in the original design study for FT production and with a HHV of 29.7 MJ per kg for ethanol [8]. Note

that the original design study for FT production includes concurrent production of two types of FT liquids for each model version: FT diesel and FT gasoline—heating values for each are provided on a HHV basis [3]. The only modification to the published bio-fuel production rates is to increase the wood-based ethanol production rate as described above.

Net electricity generation is modeled by subtracting the total parasitic load from the gross electricity generation. Gross generation for bio-ethanol production systems with CCS is modified as described above and incorporated without modification for FT production systems. The total parasitic load is equal to the published parasitic load plus the electricity required for PCS capture and CO₂ compression, as described above.

CO₂ emission accounting assumes that biomass is delivered on a carbon-neutral basis—implicitly assuming sustainable biomass production systems and ignoring both small fossil emissions from production and transport and net carbon flows between the soil and atmosphere. As such, net emissions are defined equal to the sum of net emissions from CO₂ capture for geologic storage, as defined above (100% of fermentation off-gas streams, 90% of CO₂ in the combustor exhaust streams, and 100% of the PCS streams in FT production systems), and net emissions from electricity imports / exports. CO₂ emissions from electricity imports are added using a gross carbon intensity of U.S. electricity of 0.58 TCO₂ per MWh, calculated by dividing total 2004 CO₂ emissions from electricity generation by total electricity generation in 2004 [9, 10].

Credit for electric sector mitigation from electricity exports is handled with two alternate CO₂ accounting methodologies. In the first, they are ignored for simplicity; however, this provides an incomplete picture because electricity exports should theoretically be credited for the associated mitigation (e.g., through an electric sector carbon price or market premiums for low-carbon electricity). Sector-specific carbon accounting may provide the most accurate picture of the production facility's emissions profile; however, this would create substantial additional complexity and require a broader set of assumptions. To the extent that emissions credits are tradable, it is plausible that electric sector mitigation could be credited to the facility's primary product: bio-fuel. Therefore, in the second accounting methodology electric sector carbon emissions mitigated are subtracted from the bio-fuel carbon emissions. Defining an ideal accounting methodology is subject to debate, but the alternate computations developed here represent plausible bounding estimates for net bio-fuels emissions: zero credit and full credit for electric sector mitigation.

The production segment of the model uses the results described above to compute biomass-to-bio-fuels conversion efficiency (“ η_{Biofuel} ”), total energy efficiency—including bio-fuels and electricity production (“ η_{Total} ”), carbon emissions on a bio-fuel specific basis (“ $\text{CO}_{2,\text{Biofuel}}$ ”), and the bio-fuel fraction of a carbon neutral fuel blend (“ $\%_{\text{Biofuel}}$ ”). η_{Biofuel} is computed as the HHV energy ratio of bio-fuel output to biomass input, as described in Equation 1. The computation for η_{Total} depends on the sign of net generation: if net generation is positive, then it is added to the energy outputs as described in Equation 2; if it is negative, then it is subtracted from (adding its absolute

value to) the energy inputs, as described in Equation 3. Specific carbon emissions are computed as the ratio of net emissions to bio-fuel production, as described in Equation 4. $\%_{\text{Biofuel}}$ is computed on volumetric and energy bases according to Equation 5 under the assumption that all negative emissions from bio-fuel production could be applied to offset positive emissions from the fossil fuel portion of a fuel blend. This enables a bio-fuel blend to be carbon neutral even with substantial contributions from fossil fuels.

$$(1) \quad \eta_{\text{Biofuel}} = \frac{\text{Energy}_{\text{Biofuel}}}{\text{Energy}_{\text{BiomassInput}}}$$

If net generation is positive, then:

$$(2) \quad \eta_{\text{Total}} = \frac{\text{Energy}_{\text{Biofuel}} + \text{Energy}_{\text{Electricity}}}{\text{Energy}_{\text{BiomassInput}}}$$

If net generation is negative, then:

$$(3) \quad \eta_{\text{Total}} = \frac{\text{Energy}_{\text{Biofuel}}}{\text{Energy}_{\text{BiomassInput}} + \text{Energy}_{\text{Electricity}}}$$

$$(4) \quad \text{CO}_{2,\text{Biofuel}} = \frac{\text{CO}_{2,\text{Plant}}}{\text{Energy}_{\text{Biofuel}}}$$

$$(5) \quad \%_{\text{Biofuel}} = \frac{\text{CO}_{2,\text{Gasoline}}}{\text{CO}_{2,\text{Biofuel}} - \text{CO}_{2,\text{Gasoline}}}$$

which is derived from:

$$(6) \quad CO_{2,Blend} = 0 = \left[\%_{Biofuel} \times CO_{2,Biofuel} \right] + \left[(1 - \%_{Biofuel}) \times CO_{2,Gasoline} \right]$$

D2. Bio-fuels economic model.

The bio-fuels economic model is developed to compute plant-gate bio-fuel production costs and mitigation costs. The economic model is divided into three segments: capital costs; O&M costs; and results. Each of these model segments is characterized below.

Capital costs. Capital costs are computed as the sum of costs from the base plant, CO₂ capture, and CO₂ compression. Capital costs from the base plant are adapted from those published in the original design studies [1-3]. Base-plant costs for the wood-based ethanol system, which were originally published in year 1997 U.S. dollars, are converted to year 2000 U.S. dollars (“\$U.S.”) using the *Chemical Engineering Plant Cost Index*. Base-plant costs for the corn stover-based ethanol system are incorporated as published (in year 2000 U.S. dollars). Base-plant costs for FT systems are converted from year 2002 € to year 2002 \$U.S. with the published conversion factor of 0.88 \$U.S. per €. These costs should arguably be converted to year 2000 \$U.S., but are left in year 2002 \$U.S. as the difference in costs from inflation appears to be small in these years relative to the potential error introduced by the currency conversion.

Capital costs for CO₂ capture are adapted from the IPCC Special Report on Carbon Capture and Storage [6], specifically from the results presented for “subcrit units / low rank coals” in Table 3.2 titled “CO₂ capture costs: new pulverized-coal power plants using current technology.” Results from three analyses are presented under this heading, including specific capital costs [\$/kW] (“CapEx”), capacity (“MW”) [MW], and CO₂ captured (MT/yr) for a reference plant and capture plant with PCC. For each study, the incremental total capital requirement (“DTCR”) associated with PCC is evaluated according to the Equation 7 below. This incremental total capital requirement is scaled to that of the current model based on the relative quantities of CO₂ captured and the highest resulting incremental capital cost developed from the results of the three analysis presented in [6] is used in the current model as the capital cost for CO₂ capture, as defined in Equation 8 below.

$$(7) \quad DTCR = \left[CapEx_{Capture} \times MW_{Capture} \times \frac{1}{1000} \right] - \left[CapEx_{Baseline} \times MW_{Baseline} \times \frac{1}{1000} \right]$$

$$(8) \quad TCR_{CO_2 Capture} = \text{Max}_{i=[1,2,3]} \left[DTCR_i \times \left(\frac{Q_{CO_2,i}}{Q_{CO_2,Model}} \right)^{0.7} \right]$$

where “*i*” the represents results from each of the analyses identified above from [6].

Capital costs for CO₂ compression are developed from the equations presented in [7].

The published equations develop capital cost estimates in year 2005 \$U.S. for each of the five stages of compression, which bring CO₂ pressure to 7.38 MPa, and the pump, which

boosts pressure to 15 MPa. These costs are added together to give the total capital cost for CO₂ compression. Resulting capital cost estimates are left in year 2005 \$U.S.

Capital costs from the base plant, CO₂ capture, and CO₂ compression are added together to yield total capital costs for each bio-fuel production system modeled. Resulting costs are divided by the bio-fuel production rate to yield energy output-specific capital costs ($\$/W_{\text{Biofuel}}$).

O&M. O&M is computed as the sum of non-fuel O&M from the base plant, O&M for CO₂ capture, O&M for CO₂ compression, a fee for CO₂ transport and storage, fuel costs, and the net value of electricity imports / exports. The base plant O&M is taken directly from the original design studies [1-3]. O&M for CO₂ capture and CO₂ compression are both approximated as 4% of the capital costs associated with these model components, as described above [7]. The CO₂ transport and storage fee assumed is equal to \$10 per TCO₂ [7, 11]. Electricity imports and exports are both valued at 4 cents per kWh. Fuel costs are defined by dividing an assumed delivered fuel price of \$50 per dry ton by the fuel HHV's, described above, and multiplying by the inverse of η_{Biofuel} . Annual O&M costs are converted to a specific energy output basis by dividing by the annual bio-fuel production rate, assuming a capacity factor of 0.95, which is generally consistent with the assumed capacity factors in the original design studies, as discussed below.

Results. Economic model results include producer costs of bio-fuels and mitigation costs. Producer costs are calculated as the sum of amortized capital costs and O&M costs, as described above. Capital costs are amortized over 20 years assuming an annual discount rate of 10% and a capacity factor of 0.95. These assumptions are generally consistent with those in the underlying studies. The ethanol production studies ([1] and [2]) assume a 20 year economic lifetime, a 10% discount rate, and a capacity factor of 0.96. The FT production study ([3]) assumes a 15 year economic lifetime, a 25 year technical lifetime, and a capacity factor of 0.91.

Mitigation costs are defined as the difference in producer cost divided by the difference in carbon emissions for each bio-fuel production system relative to gasoline. Gasoline is assumed to have specific emissions of 0.018 TC/GJ [9], and producer costs of 7 and 14 dollars per GJ. These assumed gasoline costs are intended to reflect oil prices of 27 and 54 dollars per barrel, respectively, as discussed in Section 3.4.3 of the main thesis text. Mitigation costs are calculated with both carbon accounting methodologies discussed in Section D1 (ignoring electric-sector mitigation and crediting the bio-fuels for electric-sector mitigation).

D3. Model data

Model data is provided in three tables. Table D1 documents the engineering model except for computations associated with CO₂ compression; Table D2 documents

computations associated with CO₂ compression, based on the equations in [7]; and Table D3 documents the economic model.

Table D1
Bio-fuels engineering model

Product Model Basis Configuration	Design basis											
	Ethanol Wooley 2 Base	Ethanol Wooley 3 OG	Ethanol Wooley 4 OG+PCC	Ethanol Aden 1 Base	Ethanol Aden 2 OG	Ethanol Aden 3 OG+PCC	FT H21 Base-A	FT H22 Base-B	FT H40 Base-C	FT H36 CCS-A	FT H37 CCS-B	FT H39 CCS-C
	Biomass feed											
Feed type	Wood	Wood	Wood	Stover	Stover	Stover	Wood	Wood	Wood	Wood	Wood	Wood
Feed HHV (MJ/kg) ^a	20	20	20	18	18	18	20	20	20	20	20	20
Feed rate (dry t per hr)	83	83	83	83	83	83	72	72	72	72	72	72
Carbon input (t/hr) ^a	42	42	42	39	39	39	36	36	36	36	36	36
Feed rate (MW)	463	463	463	416	416	416	400	400	400	400	400	400
	Fermentation offgases											
CO ₂ (t/hr) ^b	21	21	21	23	23	23	N/A	N/A	N/A	N/A	N/A	N/A
CO ₂ (kmol/hr) ^b	476	476	476	532	532	532	N/A	N/A	N/A	N/A	N/A	N/A
Percent of input Carbon ^b	14%	14%	14%	16%	16%	16%	N/A	N/A	N/A	N/A	N/A	N/A
	Biomass gasification / combustion											
Gross power generation (MW)	40	40	29	30	30	22	13	5	29	25	85	17
Generator efficiency (e/boiler feed)	0.15	0.15	0.15	0.15	0.15	0.15						
Energy to boiler (MW)	264	264	264	207	207	207						
Fraction of input energy to boiler ^b	0.57	0.57	0.57	0.50	0.50	0.50						
CO ₂ capture system	None	None	Amine	None	None	Amine	None	None	None	Glycol	Glycol	Glycol
Carbon to capture system (t/hr) ^b	24	24	24	18	18	18	0	0	0			
CO ₂ capture rate	0	0	0.9	0	0	0.9	0	0	0			
CO ₂ captured (t/hr)	0	0	78	0	0	59	0	0	0	65	63	64
CO ₂ captured (kmol/hr)	0	0	1783	0	0	1980	0	0	0	1483	1423	1447
Percent carbon input captured	0%	0%	51%	0%	0%	61%	0%	0%	0%	49%	47%	48%
Parasitic Load: CO ₂ capture (MW) ^c	0	0	7.2	0	0	5.4	0	0	0	0	0	0
Parasitic Load: CO ₂ compression (MW)	0	2.4	11	0	2.7	9.4	0	0	0	7.4	7.1	7.3
Parasitic Load: balance of plant (MW) ^b	33	33	33	12	12	12	17	17	17	18	19	28
Net electricity generation (MW)	6.6	4.2	-23	19	16	-4.2	-4.3	-12	12	-0.8	59	-19
	Production											
Biofuel1 production (t/hr) ^{b,d}	22	22	22	25	25	25	1.9	1.9	1.9	1.9	2.7	2.0
Biofuel2 production (t/hr) ^e	0	0	0	0	0	0	11	11	11	11	4.7	12
CO ₂ for geological storage (t/hr)	0	21	99	0	23	82	0	0	0	65	63	64
Net electricity generation (MW)	7	4	-23	19	16	-4	-4	-12	12	-1	59	-19

Table D1 ---Continued---

Product Model Basis Configuration	Design basis											
	Ethanol Wooley 2	Ethanol Wooley 3	Ethanol Wooley 4	Ethanol Aden 1	Ethanol Aden 2	Ethanol Aden 3	FT H21	FT H22	FT H40	FT H36	FT H37	FT H39
	Base	OG	OG+PCC	Base	OG	OG+PCC	Base-A	Base-B	Base-C	CCS-A	CCS-B	CCS-C
	Summary rates: Energy accounting											
Ethanol production rate (gal/Mtbiomass) ^b	89	89	89	99	99	99	0	0	0	0	0	0
Biofuel1 HHV (MJ/kg) ^d	30	30	30	30	30	30	48	48	48	48	49	48
Biofuel2 HHV (MJ/kg) ^e	0	0	0	0	0	0	47	47	47	47	47	47
Biofuel production (MW)	182	182	182	203	203	203	175	175	175	175	98	180
Energy efficiency: Biofuel production	0.39	0.39	0.39	0.49	0.49	0.49	0.44	0.44	0.44	0.44	0.25	0.45
Energy efficiency: Total	0.41	0.40	0.37	0.53	0.53	0.48	0.43	0.43	0.47	0.44	0.39	0.43
Energy balance (% accounted)	96%	96%	96%	98%	98%	98%	44%	44%	44%	44%	25%	45%
	Summary rates: Carbon accounting											
Percent carbon input in Biofuel ^f	28%	28%	28%	33%	33%	33%	32%	32%	32%	32%	18%	33%
CO2 capture rate	0	0.14	0.65	0	0.16	0.58	0	0	0	0.49	0.47	0.48
Specific CO2 emissions (tC/GJ)	0	-8.7	-36	0	-8.7	-30	1.1	2.9	0	-28	-48	-22
Specific CO2 emissions (tC/GJ)	-1.6	-10	-36	-4.0	-12	-30	1.1	2.9	-3.1	-28	-75	-22
Specific CO2 emissions (tC/tbio)	0	-69	-325	0	-77	-270	0	0	0	-246	-236	-240
Specific CO2 emissions (tC/Gal)	0	-0.78	-3.2	0	-0.78	-2.7	0	0	0	-3.7	-6.4	-2.9
Carbon balance (% accounted) ^g	98%	98%	98%	95%	95%	95%	32%	32%	32%	81%	65%	81%
% biofuel in carbon-neutral blend (%vol)	100%	75%	43%	100%	75%	47%	106%	119%	100%	39%	27%	45%
% biofuel in carbon-neutral blend (%E)	100%	68%	34%	100%	68%	38%	106%	119%	100%	40%	28%	45%

Notes:

^a Corn stover properties estimated as average from 12 samples published on NREL biomass feedstock composition and property database [4], wood carbon content is assumed to be 50%wt.

^b Detailed modeling results are reported by Wooley et al. only for the system with an ethanol production rate of 75 gallons per Mt biomass, we scale these results to model systems with a production rate of 89 gallons per Mt biomass assuming (i) fermentation offgas rates are proportional to ethanol production rates, (ii) the additional energy embodied in increased ethanol production is subtracted from boiler energy input, (iii) the carbon in boiler exhaust is proportional to boiler energy input, and (iv) the increased production rate does not increase the plant's parasitic load (units are as published).

^c Parasitic load of carbon capture refers to the incremental parasitic load above the plant-wide parasitic load reported in the literature, FT-CCS cases have no incremental parasitic load as carbon capture is already included in the originally published results.

^d Bio-fuel1 refers to ethanol in the cases modeled from [1] and [2], and FT diesel fuel for cases modeled from [3]

^e Bio-fuel2 in cases modeled from [3] refers to FT gasoline.

^f Carbon content of FT liquids is assumed equal to that of gasoline.

^g Incomplete carbon balances in ethanol cases are consistent with the originally published analysis (pp. 54 [1]), as additional carbon flows exist that are not counted here, including ash, gypsum, aerobic vent, and additional losses to the atmosphere (though the source of such losses is unclear); and incomplete carbon accounting in FT cases are due to zero accounting of carbon that is neither embodied in the fuel or captured.

Table D2

Compressor power requirements and capital costs (based on the equations described in [7])

Constants		Optimal compression ratio		Stage-specific parameters									
R (kJ/kmol-K)	8.314	P(initial) (Mpa)	0.1	Stage	1	2	3	4	5				
M (kg/kmol)	44.01	P(final) (Mpa)	15	Z(s)	0.995	0.985	0.97	0.935	0.845				
Tin (K)	313.15	P(cut-off) (Mpa)	7.38	k(s)	1.277	1.286	1.309	1.379	1.704				
h(is)	0.75	N(stage)	5	T(in) (K)	313.15	356	356	356	356				
h(p)	0.75	Compression ratio	2.3638										
r	630												
kg/ton	1000												
hrs/day	24												
sec/hr	3660												
Model-specific calculations													
Design basis													
Biofuel model	Wooley 2	Wooley 3	Wooley 4	Aden 1	Aden 2	Aden 3	H21	H22	H40	H36	H37	H39	
Configuration	Base	OG	OG+PCC	Base	OG	OG+PCC	Base-A	Base-B	Base-C	CCS-A	CCS-B	CCS-C	
CO ₂ flowrate (T/day)	0	503	2386	0	562	1978	0	0	0	1566	1503	1528	
Power requirements													
<i>Compressor</i>													
kW(s,1)	0	425	2016	0	475	1672	0	0	0	1324	1270	1291	
kW(s,2)	0	479	2275	0	536	1886	0	0	0	1493	1433	1457	
kW(s,3)	0	475	2254	0	531	1868	0	0	0	1479	1419	1443	
kW(s,4)	0	466	2210	0	520	1832	0	0	0	1451	1392	1416	
kW(s,5)	0	448	2126	0	501	1763	0	0	0	1396	1339	1362	
MW(total)	0	2	11	0	3	9	0	0	0	7	7	7	
<i>Pump</i>													
MW	0.00	0.09	0.45	0.00	0.10	0.37	0.00	0.00	0.00	0.29	0.28	0.29	
<i>Total</i>													
MW	0	2	11	0	3	9	0	0	0	7	7	7	
Capital costs													
<i>Compressor</i>													
Flowrate "m" (kg/s)	0	9.8134	46.5675	0	10.9649	38.6056	0	0	0	30.5667	29.3283	29.8246	
Comp. (2005\$M)	0	15.2649	28.3837	0	15.9544	26.3404	0	0	0	24.0006	23.6084	23.7667	
<i>Pump</i>													
Pump (2005\$M)	0	0.17418	0.56437	0	0.18641	0.47985	0	0	0	0.3945	0.38136	0.38663	
<i>Total</i>													
Total Capital cost	0	15.4391	28.948	0	16.1408	26.8202	0	0	0	24.3951	23.9897	24.1534	

Table D3
Bio-fuels economic model

Assumptions												
Capacity factor	0.9											
Discount rate	0.1											
Economic life (yrs)	20											
Currency conversion (\$/Euro)	0.88											
Value of electricity imports/exports (c/kwh)	4											
Electricity import emissions (tCO2/MW/hr)	0.58											
CO2 transport & Storage fee (\$/tCO2)	10											
CO2 capture heat requirement (GJth/tCO2)	3.3											
CO2 capture electricity requirement (GJe/tCO2)	0.33											
Scale basis for Capture costs (tCO2/hr)	355											
Cost basis for CO2 capture captial cost (\$M)	210											
Capital cost scaling factor	0.7											
CO2 Capture O&M cost (% capital cost)	0.04											
CO2 compression O&M cost (% capital cost)	0.04											
Delivered fuel price (\$/dry ton)	50											
Gasoline emissions factor (tC/GJ)	0.018											
Model -specific calculations												
Design basis												
Product	Ethanol	Ethanol	Ethanol	Ethanol	Ethanol	Ethanol	FT	FT	FT	FT	FT	FT
Model Basis	Wooley 2	Wooley 3	Wooley 4	Aden 1	Aden 2	Aden 3	H21	H22	H40	H36	H37	H39
Configuration	Base	OG	OG+PCC	Base	OG	OG+PCC	Base-A	Base-B	Base-C	CCS-A	CCS-B	CCS-C
Capital investment												
Base plant (\$M)	238	238	238	197	197	197	230	217	251	289	316	333
CO2 capture (\$M)	0	0	44	0	0	33	0	0	0	0	0	0
CO2 Compression (\$M)	0	15	29	0	16	27	0	0	0	24	24	24
Total (\$M)	238	254	311	197	214	257	230	217	251	289	316	333
O&M												
Base plant (\$M/yr)	18	18	18	21	21	21	13	13	13	13	15	16
Capt. & comp. (\$M/yr)	0	0.62	2.9	0	0.65	2.4	0	0	0	0.98	0.96	0.97
Trans. & storage (\$M/yr)	0	1.7	7.8	0	1.8	6.5	0	0	0	5.1	4.9	5.0
Net electricity (\$M/yr)	-2.3	-1.5	8.0	-6.6	-5.6	1.5	1.5	4.1	-4.3	0.29	-21	6.6
Fuel cost (\$M/yr)	33	33	33	33	33	33	29	29	29	29	29	29
Results												
Production price (\$/GJ)	15	16	18	13	14	16	14	14	13	16	23	18
Production price (\$/Gal) ^a	1.3	1.4	1.6	1.2	1.2	1.4	1.8	1.9	1.8	2.1	3.1	2.4
COMb (\$/TC)	409	304	203	306	234	171	370	425	317	187	240	264
COMc (\$/TC)	1	28	65	-102	-42	15	-64	-61	-92	25	127	80
COMd (\$/TC)	376	293	203	251	207	171	370	425	271	187	171	264
COMe (\$/TC)	1	27	65	-83	-38	15	-64	-61	-78	25	91	80

Notes:

^a Energy density for FT is assumed equal to gasoline. ^b & ^c Mitigation costs ignoring electric sector mitigation with oil prices at \$27 and \$54/bbl, respectively. ^d & ^e Mitigation costs crediting biofuels for electric sector mitigation with oil prices at \$27 and \$54/bbl, respectively.

Appendix D references

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Appendix E

Stochastic energy cost model documentation

Appendix E

Stochastic energy cost model documentation

This appendix is divided into three sections: Section E1 defines the equations used in the stochastic energy cost model; Section E2 defines the parameter values and distributions used in the stochastic energy cost model; and Section E3 documents the resulting model outputs.

E1. Equations

Fundamentally, the stochastic energy cost model evaluates producer costs of energy products and energy output-specific net carbon emissions for each production system modeled using probability distribution functions to explicitly characterize uncertainty in key model parameters. These results are combined across production systems to evaluate mitigation costs, which are, in turn, combined in various ways to understand the relative economics of alternate energy products and production systems.

Producer costs of energy products are defined according to Equation 1.

$$(1) C_{producer} = C_{capital} + C_{O\&M} + C_{fuel} + C_{T\&S} + C_{CarbonTax}$$

Input parameters for Equation 1 are defined as:

- C_{producer} = Producer cost of energy products
- C_{capital} = Cost of capital on an energy output basis
- $C_{\text{O\&M}}$ = Cost of non-fuel O&M for the plant on an energy output basis
- C_{fuel} = Fuel cost on an energy output basis
- $C_{\text{T\&S}}$ = Cost of CO₂ transport and storage on an energy output basis
- $C_{\text{CarbonTax}}$ = Cost of CO₂ emissions, modeled as a tax, on an energy output basis

C_{capital} is evaluated by amortizing technology-specific capital costs [$\$/W_{\text{capacity}}$], defined with probability distribution functions, over 20 years with 10% annual interest rate. The resulting annual capital cost [$\$/W_{\text{capacity}}\text{yr}$] is divided by the annual energy output [GJ] according to Equation 2, where “CF” represents the annual operating capacity factor.

$$(2) \quad \$/GJ_{\text{Output}} = \frac{\$}{W_{\text{capacity}}\text{yr}} \times \frac{1}{CF \left[\frac{W_{\text{output}}\text{yr}}{W_{\text{capacity}}\text{yr}} \right] \times 3.1536 \times 10^{-2} \left[\frac{GJ_{\text{output}}}{W_{\text{output}}\text{yr}} \right]}$$

Probability distributions for technology-specific capital costs [$\$/W_{\text{capacity}}$] are provided in Section E2. Certain energy system distributions are defined based on the assumption that the underlying conversion technology is similar to that used in other energy systems. Sampling from independently defined capital cost distributions for these systems could yield illogical results—e.g., capital costs for coal IGCC with CCS could be lower than those for coal IGCC without CCS. To avoid such sampling problems, capital costs for CCS systems are defined as the product of the capital cost associated with the system

assumed to have similar underlying technology, defined with a probability distribution function, and a capital cost ratio [cost ratio = (CCS system cost) / (base system cost)], also defined with a probability distribution function. As oxygen-blown biomass IGCC is envisioned as underlying technology similar to coal IGCC, its capital costs are similarly defined with a capital cost ratio [cost BIGCC₀ = (cost CIGCC) * (BIGCC₀ cost ratio)].

Capital costs for cofire and cofire retrofits involve unique calculations. Cofire capital costs are defined as equal to PC capital costs plus the fraction of biomass energy input (set to 15%) times a “cofire premium”. PC capital costs and the cofire premium are both defined with probability distribution functions specified in Section E2. Cofire systems with CCS use the same capital cost ratio as PC-CCS systems, but this ratio is multiplied by the cofire capital cost rather than the PC capital cost.

C_{O&M} is estimated as a percentage of specific capital cost [\$/W_{capacity}]. Different percentages are used for fossil fuel and biomass technologies, as defined in Section E2. This annual cost is divided by the annual energy output [GJ] according to Equation 2.

C_{fuel} cost is defined by dividing the delivered fuel price [\$/GJ], defined with a probability distribution function, by the HHV net plant efficiency.

C_{T&S} is estimated by multiplying the energy output-specific quantity of CO₂ captured by a deterministic transport and storage fee of \$10 per tCO₂. The energy output-specific quantity of CO₂ captured (“CO_{2,captured}”) is estimated as a function of fuel carbon intensity

(“ CI_{fuel} ”) [kgC/GJ], HHV net plant efficiency (“ η ”), and carbon capture rate (“ $\%C_{capture}$ ”) according to Equation 3.

$$(3) \quad CO_{2,captured} = \frac{CI_{fuel}}{\eta} \times \%C_{capture} \times \frac{44[tCO_2]}{12,000[kgC]}$$

$C_{CarbonTax}$ is similarly estimated by multiplying the energy output-specific net carbon emissions (“ $Emissions_{C,Net}$ ”) by alternate deterministic tax rates of \$0 and \$400 per tC. The energy output-specific carbon emissions are estimated according to Equation 4.

$$(4) \quad Emissions_{C,Net} = \frac{CI_{fuel}}{\eta} \times (1 - \%C_{capture}) \times \frac{1[tC]}{1,000[kgC]}$$

Carbon mitigation costs (“ C_{CM} ”) are calculated for each bio-energy system relative to new pulverized coal (“ PC_{new} ”) for electric sector technologies and relative to gasoline for bio-fuel technologies, according to Equation 5.

$$(5) \quad C_{CM} = \frac{C_{producer,biomass} - C_{producer,baseline}}{Emissions_{C,Net,baseline} - Emissions_{C,Net,biomass}}$$

The market entry carbon price (“MECP”) is defined by the maximum carbon mitigation cost when mitigation costs are calculated relative to all fossil fuel technologies in the appropriate energy sector and, for Biomass-CCS systems, relative to non-CCS bio-energy systems with similar underlying technology. For example, the MECP for BIGCC-

CCS is equal to the maximum mitigation cost calculated relative to each electric sector fossil fuel technology and relative to BIGCC.

Integrating the Equations 1 through 5, as discussed above, with the parameter distributions defined in Section E2 enables analysis of stochastic dominance relations between the various technologies included in the model using Monte Carlo simulation. Relations of absolute dominance are evaluated by defining the difference between specific combinations of mitigation costs or of MECP's as a simulation output. For example, the cross sector dominance of bio-energy systems is evaluated by subtracting the MECP of the minimum mitigation cost bio-fuel technology from the MECP of the minimum mitigation cost electric sector bio-energy technology; sector dominance is indicated by the sign of the result.

Probabilistic sensitivity analysis of the cross sector dominance of bio-energy systems is accomplished by parametric testing of delivered fuel prices for gasoline, natural gas, and biomass in Monte Carlo simulation. Specifically, for each parameter tested, the simulation is run four times using all model distributions defined in Section E2, except for that of the parameter being tested, which is instead defined with a series of discrete values. Discrete values used in the parametric testing sensitivity analysis are indicated in the legends of Figure 3.13.

E2. Parameter values and distributions

Model parameters and distributions are generally characterized in Tables 3.5 through 3.7 and in Figures 3.10 and 3.11. These distributions were developed from published projections [1, 2], from published engineering-economic analysis results [3], and from an expert elicitation, as described below, with reference to the engineering-economic analyses described in Sections 3.3, 3.4 and Appendixes C and D. However, the tables and figures presented in Chapter 5 do not distinguish between the distributions for capital costs and those for capital cost ratios, as discussed in Section E1. These distributions are provided in Table E1. Distributions for capital cost ratios are developed such that distributions resulting from their application match as closely as possible to capital cost distributions that were independently developed for each energy system.

Table E1
Capital cost and capital cost ratio distributions

Technology	Capital cost parameters [\$/W]		
	Min	Mode	Max
Base technology capital costs			
PC	1.10	1.25	1.65
CG	1.10	1.40	1.75
NGT	0.47	0.55	0.75
BG(BCL)	1.05	1.25	1.97
BE	1.30	1.59	1.95
BFT	1.30	1.59	2.00
Co-fire Premium	0.10	0.20	0.30
Capital cost ratios			
PC-CS:PC	1.59	1.60	1.61
CG-CS:CG	1.26	1.29	1.33
NGT-CS:NG	1.81	1.82	1.87
BG(O)-CCS:BG(O)	1.26	1.29	1.33
BG(O):CG	1.20	1.20	1.21
BG-CS(SG):BG-CS(NR)	1.11	1.16	1.16
BG-CS(FG):BG-CS(NR)	1.25	1.31	1.33
BG-CS(NR):BG	1.37	1.43	1.43
BE-CS(OG):BE	1.04	1.07	1.13
BE-CS(OG+FG):BE	1.23	1.31	1.32
BFT-CCS:BFT	1.35	1.37	1.38

Note: “PC” is pulverized coal; “CG” is coal IGCC; “NGT” is natural gas turbine combined cycle; “BG(BCL)” is biomass IGCC using the BCL/FERCO gasifier; “BE” is bio-ethanol; “BFT” is biomass FT liquids; “Co-fire Premium” is the incremental capital cost for implementing biomass co-fire at the rate of 15% energy input; “-CS” refers to a system with CCS; “BG(O)” is biomass IGCC with oxygen-blown gasification; “BG-CS(SG)” is biomass IGCC-CCS with reform heat provided by burning a fraction of syngas, as described in Chapter 3; “BG-CS(FG)” is biomass IGCC-CCS with reform heat provided by burning a fraction of hydrogen-rich fuel gas, as described in Chapter 3; “BG-CS(NR)” is biomass IGCC-CCS without steam reforming; “BE-CS(OG)” is bio-ethanol production with CCS from fermentation off-gases; and “BE-CS(OG+FG)” is bio-ethanol production with CCS from fermentation off-gases and flue gases.

In addition to reviewing relevant literature, an expert elicitation was developed to inform the development of capital cost and fuel cost distributions. The elicitation consisted primarily of an annotated spreadsheet with attached instructions; limited verbal instruction was also provided upon request. The annotated spreadsheet and instructions are presented in Figures E1 and E2, respectively. The elicitation was circulated to four experts in the energy system modeling and carbon mitigation; responses from Howard Herzog, Dale Simbeck, and David Keith were considered in developing capital cost and fuel cost probability distribution functions for the stochastic energy cost model.

Figure E3 presents the technology capital cost distributions used in the stochastic model along with aggregate distributions from the expert elicitation—defined by the mean of each distribution parameter across the responses. The aggregate distribution parameter values have been converted to from year 2001 to year 2005 dollars using the Chemical Engineering Plant Cost Index [4]. Recall that published estimates were considered with the elicitation results in developing the energy cost model distributions, as noted above.

Figure E4 presents the fuel cost distributions used in the model with aggregate distributions from the elicitation responses, computed consistently with those in Figure E3. However, fossil fuel prices have increased substantially since 2001 for reasons beyond inflation. Therefore, Figure E4 also presents distributions defined by the reference, high price, and low price scenario forecasts of fuel prices in 2015 as projected by the U.S. Department of Energy in 2001 and 2007 [1, 2]. No similar points of

Please fill out the green cells in this Matrix entering specific capital costs for each technology option except for Co-fire, which is explained in the side note.
The red cells will update automatically.

CapEx (\$/kW) to achieve target efficiency for plants ordered in 2010				
Technology	HHV Eff Target	Min	Best Guess	Max
Coal PC	40%			
Coal PC with Capture	28%			
Coal IGCC	42%			
Coal IGCC with Capture	36%			
Natural Gas Combined Cycle	55%			
NGCC with Capture	47%			
CapEx Premium for 15% Co-fire (\$/W-bio)				
Co-fire	40%	0	0	0
Biomass IGCC	37%			
Biomass IGCC with capture	30%			
CapEx Ratios				
Technology	Min	Best Guess	Max	
PC with capture / PC without	#DIV/0!	#DIV/0!	#DIV/0!	
Coal IGCC with capture / C-IGCC without	#DIV/0!	#DIV/0!	#DIV/0!	
Biomass IGCC with capture / B-IGCC without	#DIV/0!	#DIV/0!	#DIV/0!	
Natural Gas CC with capture / NG-CC without	#DIV/0!	#DIV/0!	#DIV/0!	

We feel relatively comfortable in our ability to predict future fuel costs (or rather, as uncomfortable with our predictions as anyone else's), but would be interested in your opinions if you feel like giving them. Please feel free to use any units you feel most comfortable with.

Fuel Costs				
Fuel	Min	Best Guess	Max	Units
Coal				\$/GJ
Biomass				\$/GJ
NG				\$/GJ
Oil				\$/bbl

Current dollar estimates for new power plants ordered in 2010 **assuming** that more than 5 GW of capacity has been installed by 2010. (We understand that this is unlikely).

Unless you tell us otherwise we will assume that Min and Max refer to the 80% confidence interval of capital costs to meet the efficiency target.
Thus your max value, for example, should be set so you would be willing to bet that there is only a 10% chance that the capital cost will be higher than the value you give

This represents the additional capital cost of providing the capacity to co-fire 15% biomass (energy basis) in a new coal fired power plant per kW biomass capacity. The capital cost of the co-fire plant will be calculated by the following equation:
$$\text{Co-fire Capex} = \text{Coal Capex} + 15\% * (\text{Co-fire Premium})$$

Fuel Costs (feel free to skip if you want)
Feel free to use units that you are most comfortable with, but please change the indicated units to reflect your choice.
All cost (except oil) are for delivery at the plant gate in quantities needed to run a 1 GWe plant. Oil is world price (WTI or whatever you like)

Figure E.1. Annotated spreadsheet for expert elicitation.

CapEx Estimates:

1. Constant 2001 dollar estimates for new power plants contracted in 2010 with each of the specified technologies.
2. Assume that a relatively large amount of capacity (5+ GW) has been installed with each plant type before 2010 (i.e. this is not a 'next plant' estimate).

This means that we assume that 5+ GW of PC plants with carbon capture, for example, are ordered in the next few years and are on-line before 2010. The cost of the new plant ordered in 2010 is therefore based on the experience gained from these earlier projects.

We understand that this is unlikely, though not out of the question, for coal with capture and absurd for biomass with capture.

3. We want you to make cost estimates to reflect the given efficiency targets even if you don't think these are the most likely efficiency values. If you think our efficiency targets are so inappropriate that you can't make a cost estimate then please do one of the following:
 - a. Tell us what you think it should be, but base your estimates on what is listed (preferred).
 - b. Tell us what you think it should be and base your cost estimates on your number (we will deal with sorting out the conflict).
4. The costs should reflect the environmental controls that you believe will be required in 2010.
5. Capture efficiency for all capture plants is assumed to be 90% or better. Give us your assumption if you want.

Co-fire CapEx Premium:

This is the additional capital cost for co-firing biomass at 15% (energy basis) with coal, per kW electricity from biomass. This cost will be added to the CapEx from a base case PC plant to represent the additional cost of Co-firing 15% biomass according to the equation:

$$\text{CapEx}(\text{Co-fire}) = [\text{CapEx}(\text{PC})] + [(\text{Co-fire Premium}) * 15\%]$$

Figure E.2. Instructions for expert elicitation.

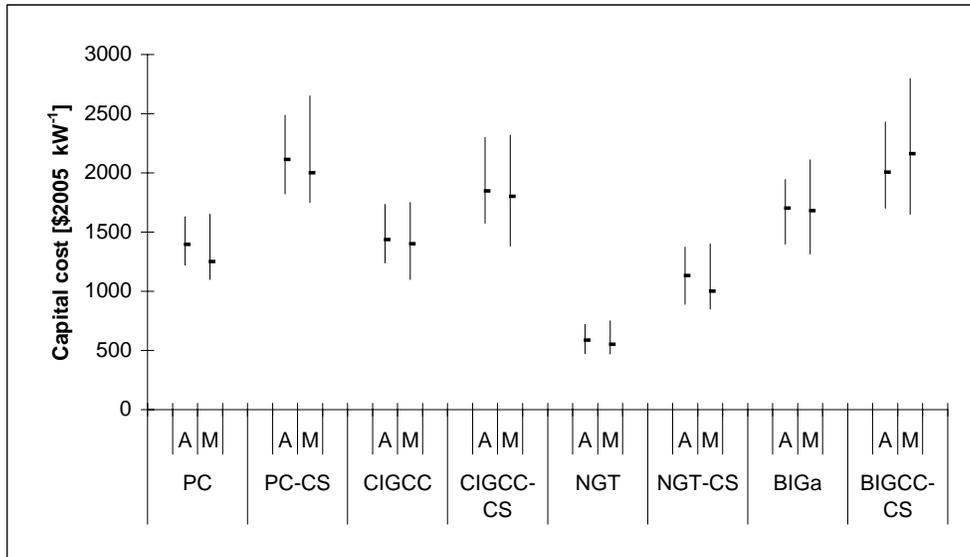


Figure E3. Distributions of expected capital costs. Aggregate capital cost distributions from the expert elicitation, converted to year 2005 dollars ("A"), are presented with distributions used in the energy cost model ("M").

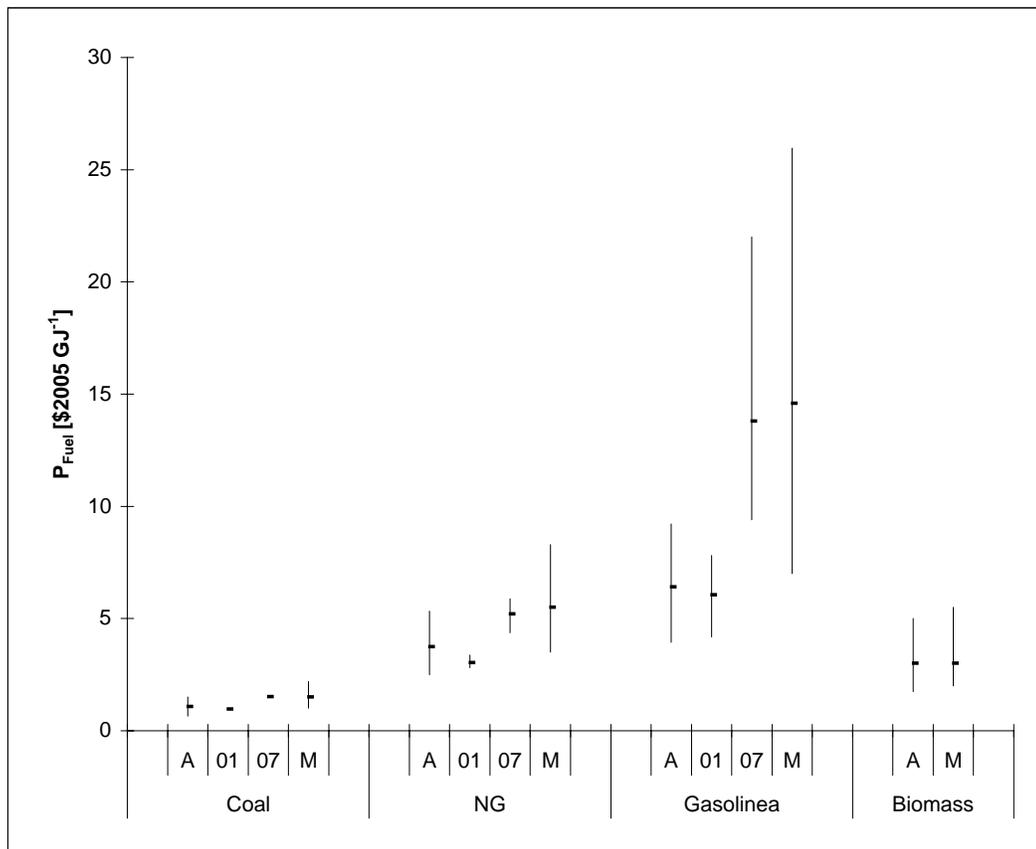


Figure E4. Distributions of projected fuel costs. Distributions of projected fuel prices are presented from: aggregate fuel cost distributions from the expert elicitation ("A"); U.S. D.O.E. estimates made in 2001 ("01"); U.S. D.O.E. estimates made in 2007 ("07"); and from the model.

reference are provided for biomass fuel costs; however, they are only indirectly subject to the drivers underlying recent increases in fossil fuel prices.

E3. Resulting data from the energy cost model

The primary results from the energy cost model are the distributions from Monte Carlo simulation presented in Figures 3.12 and 3.13; however those distributions are not transparent with respect to the underlying computations. Therefore, producer cost computation results are provided in Table E2 using expected values from the probability distribution functions. Mitigation cost and MECP computation results are similarly provided in Tables E3 and E4, respectively.

Table E2
 Producer cost and net carbon emission results (\$2005)

Energy system	C_{fuel} kgC/GJ	η HHV	C_{fuel} \$/GJ _{out}	Capital \$/W	$C_{capital}$ \$/GJ _{out}	$C_{O\&M}$ \$/GJ _{out}	$CO_{2,captured}$ TCO ₂ /GJ _{out}	$C_{T\&S}$ \$/GJ _{out}	$CO_{2,net}$ TC/GJ _{out}	Ctax \$/GJ _{out}	$C_{producer,t=0}$ \$/GJ _{out}	$C_{producer,t=400}$ \$/GJ _{out}
<i>Electric sector</i>												
Historic PC	24.2	0.35	\$ 4.48	0.00	\$ -	\$ 2.64	0.000	0.00	0.0691	27.66	7.12	34.78
PC-CCS retrofit	24.2	0.35	\$ 4.48	0.80	\$ 3.72	\$ 4.22	0.228	2.28	0.0069	2.77	14.70	17.47
PC	24.2	0.40	\$ 3.92	1.33	\$ 6.21	\$ 2.64	0.000	0.00	0.0605	24.20	12.77	36.97
PC-CCS	24.2	0.28	\$ 5.60	2.13	\$ 9.93	\$ 4.22	0.285	2.85	0.0086	3.46	22.60	26.05
CIGCC	24.2	0.43	\$ 3.64	1.42	\$ 6.60	\$ 2.81	0.000	0.00	0.0563	22.51	13.05	35.56
CIGCC-CCS	24.2	0.35	\$ 4.48	1.83	\$ 8.50	\$ 3.62	0.228	2.28	0.0069	2.77	18.88	21.64
NGCC	13.6	0.55	\$ 10.48	0.59	\$ 2.75	\$ 1.17	0.000	0.00	0.0247	9.89	14.40	24.29
NGCC-CCS	13.6	0.47	\$ 12.27	1.08	\$ 5.03	\$ 2.14	0.095	0.95	0.0029	1.16	20.40	21.55
Co-fire	24.3	0.40	\$ 4.64	1.36	\$ 6.35	\$ 2.70	0.035	0.00	0.0514	20.57	13.69	34.26
Co-fire-CCS	24.3	0.28	\$ 6.63	2.18	\$ 10.15	\$ 4.32	0.336	2.87	-0.0048	-1.90	23.97	22.07
Co-fire retrofit	24.3	0.35	\$ 5.30	0.03	\$ 0.14	\$ 2.70	0.039	0.00	0.0588	23.51	8.15	31.65
Co-fire-CCS retrofit	24.3	0.25	\$ 7.58	0.85	\$ 3.94	\$ 4.32	0.384	3.28	-0.0054	-2.17	19.12	16.94
BIGCC	25.1	0.34	\$ 10.42	1.42	\$ 6.63	\$ 3.95	0.274	0.00	0.0000	0.00	20.99	20.99
BIGCC _O	25.1	0.37	\$ 9.46	1.70	\$ 7.92	\$ 4.72	0.249	0.00	0.0000	0.00	22.09	22.09
BIGCC-CCS _{R,SG}	25.1	0.24	\$ 14.46	2.29	\$ 10.68	\$ 6.36	0.589	2.08	-0.0569	-22.74	33.59	10.85
BIGCC-CCS _{R,FG}	25.1	0.21	\$ 16.99	2.60	\$ 12.11	\$ 7.21	0.725	2.78	-0.0759	-30.36	39.10	8.74
BIGCC-CCS _{NR}	25.1	0.28	\$ 12.59	2.01	\$ 9.34	\$ 5.57	0.477	1.46	-0.0399	-15.94	28.96	13.02
BIGCC _O -CCS	25.1	0.30	\$ 11.62	2.19	\$ 10.21	\$ 6.08	0.581	2.75	-0.0750	-30.01	30.66	0.65
<i>Liquid fuels</i>												
Petrol	18.2	1.00	\$ 15.85	0.00	\$ -	\$ -	0.000	0.00	0.0182	7.28	15.85	23.13
Petrol 2	18.2	1.00	\$ 14.00	0.00	\$ -	\$ -	0.000	1.00	0.0182	7.28	15.00	22.28
BE	25.1	0.45	\$ 6.76	1.61	\$ 7.51	\$ 3.98	0.205	0.00	0.0000	0.00	18.25	18.25
BE-CCS _{OG}	25.1	0.45	\$ 6.76	1.74	\$ 8.10	\$ 4.29	0.235	0.31	-0.0084	-3.35	19.46	16.11
BE-CCS _{OG+FG}	25.1	0.45	\$ 6.76	2.07	\$ 9.65	\$ 5.11	0.327	1.23	-0.0335	-13.39	22.75	9.36
BFT	25.1	0.45	\$ 7.78	1.63	\$ 7.59	\$ 4.02	0.205	0.00	0.0000	0.00	19.39	19.39
BFT-CCS	25.1	0.45	\$ 7.78	2.22	\$ 10.34	\$ 5.48	0.307	1.02	-0.0279	-11.16	24.61	13.46

Column headings are defined in Section E1.

Table E3
Electric sector mitigation costs and MECP [$\$2005 \text{ tC}^{-1}$]

Mitigation system	Baseline								
	Pulvarized	Coal	Natural Gas	Analogous	Pulvarized	Coal	Natural Gas	MECP	MECP
	Coal	IGCC	GTCC	Non-CCS	Coal - CCS	IGCC - CCS	GTCC - CCS	without NG	with NG
PC-CCS	190	201	510	190	0	-2152	-383	201	510
CIGCC	66	0	43	N/A	201	118	138	0	0
CIGCC-CCS	114	118	251	118	-2152	0	378	118	378
NGCC	46	43	0	N/A	510	251	275	0	0
NGCC-CCS	132	138	275	275	-383	378	0	0	378
Co-fire	102	133	27	N/A	208	117	138	0	0
Co-fire-CCS	172	179	324	183	102	436	467	436	467
BIGCC	136	141	267	N/A	-186	306	206	306	306
BIGCC _O	154	161	311	N/A	-58	465	587	465	587
BIGCC-CCS _{R,SG}	177	182	235	222	168	231	221	231	235
BIGCC-CCS _{R,FG}	193	197	245	239	195	244	237	244	245
BIGCC-CCS _{NR}	161	166	225	200	131	216	200	216	225
BIGCC _O -CCS	132	134	163	114	96	144	132	144	163

Mitigation costs [$\$ \text{tC}^{-1}$] are computed for each mitigation system relative to each baseline alternative. "Analogous Non-CCS" means the non-CCS alternative with the same underlying technology. MECP is equal to the highest mitigation cost. Negative mitigation costs imply that the baseline option is higher cost than the mitigation system at zero carbon price.

Table E4
Liquid-fuels mitigation costs and MECP [$\$2005 \text{ tC}^{-1}$]

Mitigation system	Baseline			MECP
	Petrol	Analogous Non-CCS	Analogous Low-CCS	
BE	132	N/A	N/A	132
BE-CCS _{OG}	136	144	N/A	144
BE-CCS _{OG+FG}	134	134	131	134
BFT	194	N/A	N/A	194
BFT-CCS	190	187	N/A	190

See note for Table E4. "Analogous Low-CCS" means Bio-ethanol with carbon capture from fermentation off-gas only ("BE-CCS_{OG}").

References

Appendix E

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