NATIONAL ENERGY TECHNOLOGY LABORATORY

Role of Alternative Energy Sources: Pulverized Coal and Biomass Co-firing Technology Assessment

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
BAAQMD	Bay Area Air Quality Management District
BEAM	Biomass Energy Analytical Model
CO	Carbon monoxide
CCS	Carbon capture and sequestration
CH_4	Methane
CHP	Combined heat and power
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COE	Cost of electricity
DOE	Department of Energy
ECF	Energy conversion facility
eGRID	Emissions and generation resource integrated database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EROI	Energy return on investment
ESP	Electrostatic precipitator
FEMP	Federal Energy Management Program
FGD	Flue gas desulfurization
GHG	Greenhouse gas
GWP	Global warming potential
Hg	Mercury
HHV	Higher heating value
HP	Hybrid poplar
INL	Idaho National Laboratory
kg	Kilogram
kJ	Kilojoule
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
LC	Life cycle
LCA	Life cycle analysis
LCC	Life cycle cost
LCOE	Levelized cost of electricity
MACRS	Modified accelerated cost recovery system
MJ	Megajoule
MW,MWe	Megawatt electric
MWh	Megawatt-hour
N_2O	Nitrous oxide
NASS	National Agricultural Statistics Service
NH_3	Ammonia
NMVOC	Non methane volatile organic compounds
NO_X	Nitrogen oxides
NPK	Nitrogen, phosphorus, potassium
NETL	National Energy Technology Laboratory
O&M	Operating and maintenance
Pb	Lead
PC	Pulverized coal
PM	Particulate matter
PM_{10}	Particulate emissions
PT	Product transport
REC	Renewable energy credits
RFS2	Renewable fuel standard
RMA	Raw material acquisition
RMT	Raw material transport
RPS	Renewable Portfolio Standard
scf	Standard cubic feet
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T&D	Transmission and Distribution
TOC	Total overnight cost
ton	Short ton
tonne	Metric ton
U.S.	United States
USDA	U.S. Department of Agriculture
VOC	Volatile organic compounds

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Executive Summary

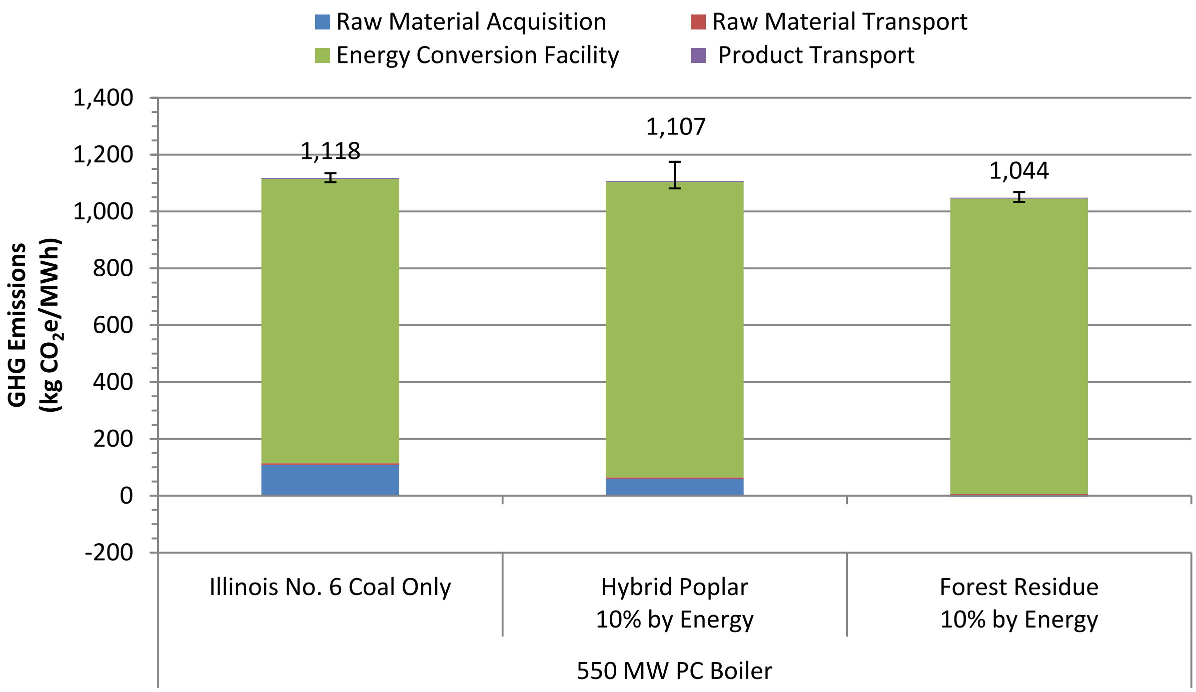
This report discusses the role of coal and biomass co-fired power in meeting the energy needs of the United States (U.S.). This includes an analysis of key issues related to co-fired power and the modeling of the environmental and cost aspects of co-fired power.

The resource base of co-fired power (combustion of coal and biomass in the same boiler) depends on the availability of coal and the various biomass feedstocks, as well as the proximity of biomass sources to coal-fired power plants. The U.S. has 261 billion tons of recoverable coal reserves; based on an average annual coal production rate of 1.5 billion tons, the estimated recoverable reserves alone will provide the U.S. with coal for the next 150+ years. The three primary types of biomass that can be used for co-fired power are agricultural residues, forest residues and thinnings, and herbaceous and woody energy crops. A comparison of the geographies of biomass resources and existing coal-fired power plants indicates high potential for co-firing agricultural residues with coal plants in Iowa and Illinois. There is also potential for co-firing in the southeast U.S., which has large forest resources and a potential for productive herbaceous or woody energy crops. Conversely, several mid-Atlantic states with large coal resources and installed capacity of coal-fired facilities such as Ohio, Pennsylvania, West Virginia, and New York lack an adequate agricultural and forest residues to support significant co-firing capacity. If the incentives for co-firing were large enough, however, co-firing could grow in these states because co-fired facilities would be able to compete with the forest products industry for standing timber.

Coal and biomass co-firing has been tested at a number of plants in the U.S. As of 2011, direct co-firing has been tested at a minimum of 38 plants. Many of these tests occurred in the late 1990s and early 2000s; very few remain in operation today. Dedicated biomass-to-energy power plants that are not tied to coal-fired power production are currently operational in California, Oregon, and other regions with sufficient feedstock availability. Many of these plants were installed in the 1980s and have been operational since. Despite the low capacity of existing co-fired power plants, the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) for 2011 shows significant growth in biomass co-firing for electricity generation through 2035. Based on the AEO projection, co-fired electricity generation peaks in 2024 at just over 30 billion kWh, nearly a factor of 20 greater than current levels (EIA, 2011). The EIA projected increase in biomass co-firing for electricity generation is driven by a combination of state renewable portfolio standard (RPS) requirements and the projected low cost of feed stocks.

The environmental profile of this analysis is based on a life cycle analysis (LCA) that accounts for a full list of metrics, including air emissions and resource consumption. It is based on a 550 MW, coal-fired power plant with a pulverized coal (PC) boiler that is retrofitted to co-fire biomass at a 10 percent feedstock-share by energy. The coal feedstock is Illinois No. 6 coal, and two types of biomass feedstocks, hybrid poplar (HP) and forest residue, are considered. HP is a dedicated energy crop that requires land preparation, cultivation, and harvesting, while forest residue is merely a byproduct of the forest product industry. The co-firing of Illinois No. 6 coal and HP reduces life cycle (LC) greenhouse gas (GHG) emissions by only 1.0 percent (from 1,118 kg CO_2e to 1,107 kg CO_2e/MWh) (**Figure ES-1**). The CO_2 emissions from the combustion of biomass are carbon neutral, but the HP supply chain also includes land transformation, fertilizer production and use, and other ancillary processes that produce significant GHG emissions. The co-firing of Illinois No. 6 coal and forest residue reduces the LC GHG emissions by 6.6 percent (from 1,119 kg CO_2e/MWh to 1,044 kg CO_2e/MWh). In contrast to HP, the acquisition of forest residue does not produce GHG emissions from land use or cultivation.

Figure ES-1: Life Cycle GHG Emissions of Coal and Biomass Power Systems



The results for other air emissions show that co-firing increases the LC lead (Pb), volatile organic compounds (VOC), and particulate matter (PM) emissions. Co-firing reduces LC SO_2 emissions if forest residue is used, but not if HP is used. Co-firing leads to reductions in LC emissions of carbon monoxide (CO), nitrogen oxides (NO_X), and mercury (Hg).

The costs of co-firing were evaluated using an LC costing approach. The retrofit of an existing PC plant to co-fire HP at a 10 percent share of feedstock energy increases the cost of electricity (COE) from $30.9/MWh to $40.4/MWh (a 31 percent increase). If forest residue is co-fired instead of HP, the increase in COE is only 14 percent. The capital costs of the co-fired systems account for a small share (approximately 8 percent) of the COE, because this analysis assigns capital costs only to new equipment, not existing equipment. The key drivers of cost uncertainty are the feedstock prices for coal and biomass.

The technical barriers to the implementation of co-fired systems include biomass supply variability as well as higher-than-expected decreases in boiler efficiencies, equipment fouling, and co-product degradation. Regulatory uncertainty is a key non-technical risk associated with co-fired systems.

1 Introduction

The role of an energy source in the national energy supply is determined by a combination of factors, including technical considerations, resource availability, environmental characteristics, economics, and other issues that may pose risks or barriers. The objective of this analysis is to conduct a broad assessment of power produced from coal and biomass co-firing using the list of criteria summarized in **Table 1-1**.

Table 1-1: Criteria for Evaluating Roles of Energy Sources

Criteria	Description
Resource Base	Availability and accessibility of natural resources for the production of energy feedstocks
Growth	Current market direction of the energy system – this could mean emerging, mature, increasing, or declining growth scenarios
Environmental Profile	Life cycle (LC) resource consumption (including raw material and water), emissions to air and water, solid waste burdens, and land use
Cost Profile	Capital costs of new infrastructure and equipment, operating and maintenance (O&M) costs, and cost of electricity (COE)
Barriers	Technical barriers that could prevent the successful implementation of a technology
Risks of Implementation	Non-technical barriers, such as financial, environmental, regulatory, and/or public perception concerns, that are obstacles to implementation
Expert Opinion	Opinions of stakeholders in industry, academia, and government

A co-fired power plant burns two types of fuels, usually coal and biomass, in the same boiler. The co-firing of coal and biomass has been practiced in the wood products industry for decades as a way of recovering energy from process wastes, but has also been practiced more recently at utility-scale boilers as a way of diversifying fuels, increasing the share of renewable fuels in a corporation's energy portfolio, and reducing greenhouse gas (GHG) emissions. The combustion of biomass also leads to reduced emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) from a power plant.

An existing coal-fired power plant can be retrofitted to combust biomass at a share of up to 20 percent of total fuel energy. Minor modifications may be made to the boiler itself, but a more significant modification is the addition of a drying and grinding system that can transform biomass to a suitable moisture content and size for co-combustion with coal. (EERE, 2004)

Coal is a fossil fuel that is the energy source for approximately half of electricity in the United States (U.S.) (EIA, 2011). Biomass includes residues from the forest industry and agriculture, but also includes crops that are grown specifically for energy feedstocks (Ortiz, Curtright, Samaras, Litovitz, & Burger, 2011). Forest residues and hybrid poplar (HP) (a dedicated energy crop) are examples of woody biomass types, while switchgrass (another dedicated energy crop) and corn stover (an agricultural residue) are examples of herbaceous biomass types.

The U.S. has a reliable infrastructure for the extraction and transport of coal, which reduces variability in coal costs. The acquisition and delivery of biomass, on the other hand, is not as reliable. The cost of delivered biomass may be favorable if a power plant is near a source of forest or agricultural residue, but the cost of delivered biomass increases as the radius of collection increases (Ortiz, et al., 2011). Competing markets for biomass can also increase the delivered cost of biomass.

2 Coal and Biomass Co-firing Technology Performance

A co-fired power plant burns two types of fuels in the same boiler. The co-firing of coal and biomass uses the same mills and burners for coal and biomass. New plants can be designed for co-firing, but most co-fired plants are retrofits to existing coal-fired systems. Co-firing of coal and biomass is a proven technology. As of 2010, there were nine facilities in the U.S. that co-fire coal and biomass for power generation for a total capacity of 469 MW. These facilities include utility-owned power plants as well as power generated by pulp and paper mills (Ventyx, 2011).

The power plant of this analysis has a PC boiler and a net output of 550 MW. The net efficiency of the coal-only power plant is 33.0 percent, which is equivalent to a heat rate of 10,909 kJ/kWh. The co-firing scenario is based on a feedstock input with 10 percent biomass by energy, which is equivalent to a net plant efficiency of 32.8 percent (10,985 kJ/kWh). The power plant has a flue gas desulfurization (FGD) unit that removes 98 percent of the SO_2 emissions in the flue gas. The power plant also has an electrostatic precipitator (ESP) unit that removes particulate matter.

As shown by the above specifications, the efficiency of a PC boiler decreases when biomass is introduced as a feedstock (Ortiz, et al., 2011). In 2000, research conducted by Foster Wheeler led to the development of a correlation between biomass co-firing rate and the decline in net plant efficiency (Ortiz, et al., 2011). Based on this correlation, the net efficiency of the power plant of this analysis decreases from 33.0 percent to 32.8 percent when biomass is co-fired at a 10 percent share of total feedstock energy.

The power plant in this analysis is an existing facility. New construction is not necessary for the coal-only scenario. The co-firing scenario requires minor boiler modifications and the addition of biomass handling equipment. Any energy required for the operation of biomass handling equipment is provided by either waste heat or electricity generated by the power plant; the energy used for the operation of biomass handling equipment is accounted for in the net plant efficiency.

The physical properties of Illinois No. 6 coal and HP were used to determine feedstock rates and CO_2 emissions. The heat rate is determined by dividing the composite heating value of the feedstocks by the boiler efficiency. CO_2 emissions are calculated by balancing the carbon inputs and outputs of the PC boiler. The key factors of the carbon balance are a 99 percent conversion rate of carbon to CO_2, and a molar ratio of 44/12 between CO_2 and carbon.

This analysis also includes a scenario that uses forest residue as a biomass feedstock instead of HP. The physical properties of HP and forest residue are the same, so the performance of the power plant does not change if forest residue is used instead of HP.

The emission of non-GHG gases is based on emission factors from similar systems and on the performance of environmental control equipment. NO_X and carbon monoxide (CO) emissions decrease when a coal-fired boiler is retrofitted to co-fire biomass because of the lower nitrogen content of biomass feedstocks in comparison to coal and the lower flame temperatures caused by the relatively high moisture of the biomass (EPRI/DOE, 1997). SO_2 emissions are a function of the sulfur content of the feedstocks and the efficiency of the FGD unit (EPRI/DOE, 1997). PM emissions are controlled by an ESP unit (EPRI/DOE, 1997). Mercury (Hg) emissions are based on the performance of a PC boiler with FGD and ESP controls (NETL, 2010b).

The performance characteristics of the coal-only and co-fired power plants are summarized in **Table 2-1**.

Table 2-1: Energy and Performance Summary for Coal and Biomass Power Technologies

Parameter	Coal Only	Co-fired Coal and Biomass
Power Summary		
Net Power, MWe	550	550
Efficiency		
Net Plant Efficiency, % (HHV)	33%	32.8%
Net Plant Heat Rate, kJ/kWh	10,907	10,983
Capacity Factor, %	85%	85%
Co-firing Ratio		
Coal, % energy	100%	90%
Biomass, % energy	0%	10%
Consumables (per hour)		
As-Received Coal Feed, kg/hr.	221,100	200,393
As-Received Biomass Feed, kg/hr.	0	57,008
Raw Water Withdrawal, L/hr.	1,382,040	1,382,040
Raw Water Consumption, L/hr.	1,070,784	1,070,784
Consumables (per MWh production)		
As-Received Coal Feed, kg/MWh	402	364
As-Received Biomass Feed, kg/MWh	0	104
Raw Water Withdrawal, L/MWh	2,513	2,513
Raw Water Consumption, L/MWh	1,947	1,947
Emissions		
CO_2, kg/MWh_{net}	930.3	942.6
$NO_{X,}$ kg/MWh	1.00	0.82
Particulates, kg/MWh	0.24	0.22
SO_2, kg/MWh	0.38	0.35
$CO_{,}$ kg/MWh	1.42	1.33
$Hg_{,}$ kg/MWh	3.50E-05	3.17E-05
Solid Waste		
Total Ash, kg/MWh	37.12	34.17

3 Coal and Biomass Co-firing Resource Base, Capacity, and Growth

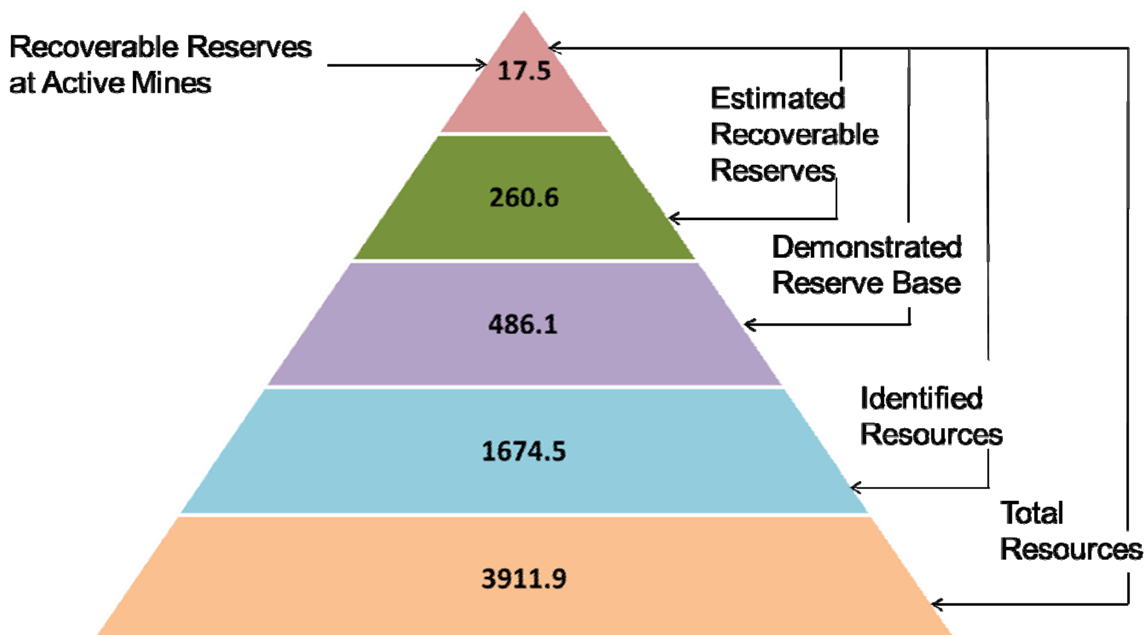
The resource base of co-fired power depends on the availability of coal and the various biomass feedstocks, as well as the proximity of biomass sources to coal-fired power plants.

To be a viable power technology, coal and biomass co-firing must have a sustainable resource base. This section discusses the projected production rates and geographical characteristics of coal and biomass feedstocks.

3.1 Coal Resource Base

As of 2011, active U.S. mines had 17.5 billion tons of coal ready for recovery. However, if current mining technologies are applied to the total resource base, the U.S. has estimated recoverable reserves of 261 billion tons of coal. As shown by **Figure 3-1**, the estimated recoverable reserves are just a fraction of the total resource base of coal.

Figure 3-1: U.S. Coal Resources and Reserves in Billion Tons (EIA, 2011)

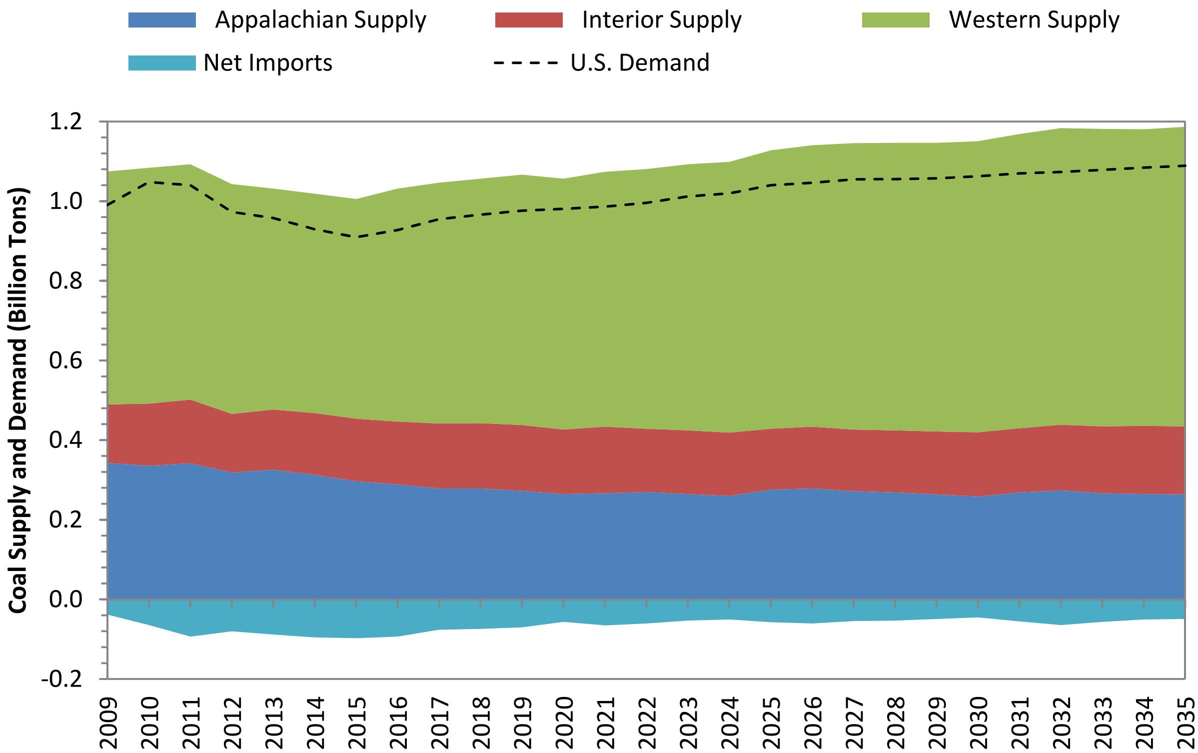


Source: U.S. Energy Information Agency. Form EIA-7A Coal Production Report (February 2011)

The Energy Information Administration's (EIA) projections of U.S. coal supply and demand, according to the Annual Energy Outlook (AEO) 2012 early release reference case, show an annual demand that ranges between 0.91 and 1.09 billion tons of coal through 2035, as shown in **Figure 3-2** (EIA, 2012). The projections for coal supply, when adjusted for net imports, correspond closely to this demand.

Ninety-three percent of U.S. coal demand is for electricity generation (EIA, 2012). The U.S. has an extensive rail network that allows for economical, reliable transport of coal between mines and energy conversion facilities. Coal mines in the Western U.S. provide more than half of the U.S. coal supply (54 percent in 2011), followed by Appalachian and Interior mines (EIA, 2012).

Figure 3-2: AEO 2012 Early Release Reference Case Coal Projections to 2035 (EIA, 2012)



Based on an average annual coal demand rate of approximately 1 billion tons, the estimated recoverable reserves (261 billion tons) represent a 261-year supply of coal.

3.2 Biomass Resource Base

The three primary types of biomass that can be used for co-fired power are agricultural residues, forest residues and thinnings, and herbaceous and woody energy crops. This analysis uses the results of the following studies to evaluate the resource base of these biomass types.

- The Billion Ton Study was prepared by Oak Ridge National Laboratory, in 2005 (ORNL, 2005). It calculates the land requirements needed to support enough biomass production to displace 30 percent of the existing petroleum fuels market. (An annual production rate of 1 billion tons of biomass is required to meet such a goal.)
- The Update to the Billion Ton Study was published in 2010 and builds on the preceding work by presenting land use and biomass production results at the county level (ORNL, 2011).
- The Milbrandt Study estimates the production rate of agricultural crop residues using U.S. Department of Agriculture (USDA) statistics (Millbrandt, 2005).
- The Biomass Energy Analytical Model (BEAM) was commissioned by the Federal Energy Management Program (FEMP) and represents work conducted by the National Energy Technology Laboratory (NETL) and a contractor (Enegis, 2011). BEAM quantifies and categorizes biomass resources at local and regional levels, including detailed geographical

resolution to the 30-meter level. It also provides details on transportation infrastructure and fuel cycle costs.

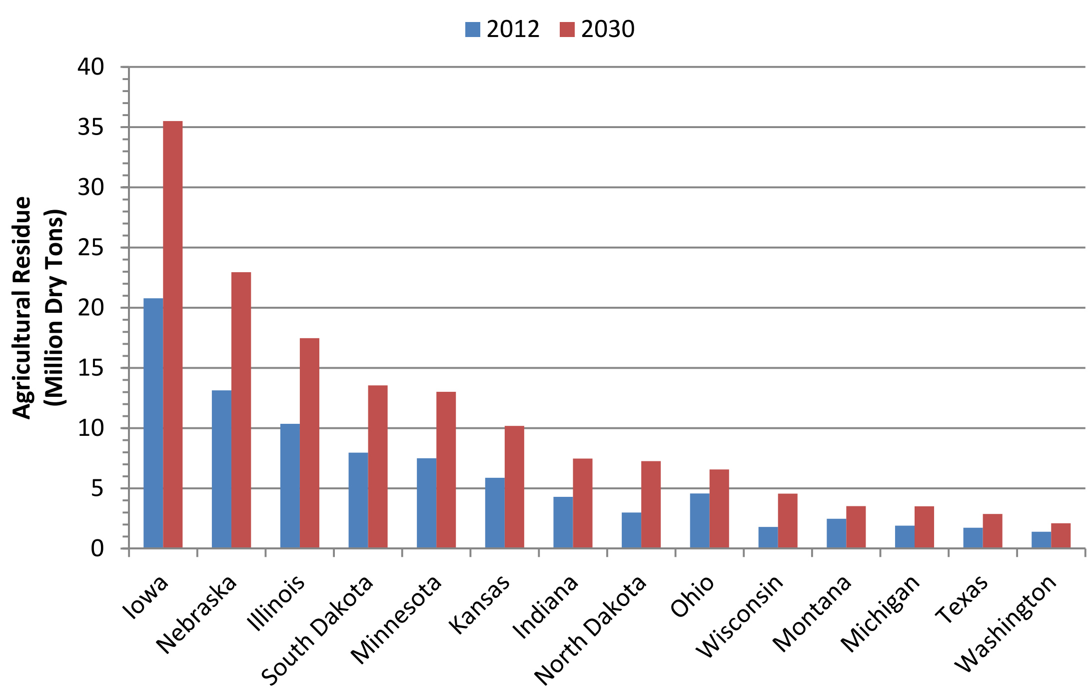
Each of the above studies has unique objectives and modeling approaches, but all are based on similar data sources. The USDA National Agricultural Statistics Service (NASS) is a common data source for agricultural residue potential (USDA, 2011). The U.S. Forest Industry is a common data source for forest residues, thinning, and HPs. Finally, POLYSYS is an economic model developed by the University of Tennessee (UTENN, 2010) and is a common data source for switchgrass (a reasonable proxy for herbaceous energy crops).

3.2.1 Agricultural Residues

The resource base of agricultural residues can be estimated by applying crop production statistics with residue-to-grain ratios. This is the method used in the Update to the Billion Ton Study, which uses the POLYSYS model (UTENN, 2010) to estimate the production rates of corn stover and other residues from grain crops. On a production basis, corn and wheat are the largest crops in the U.S. and have residue-to-grain ratios of 1 and 1.7, respectively. In other words, the production of 1 kg of corn grain produces 1 kg of corn stover and the production of 1 kg of wheat produces 1.7 kg of wheat straw. These ratios are based on research and field trials. (ORNL, 2011)

The state-level resource base of agricultural residues, as estimated by the Update to the Billion Ton Study (ORNL, 2011), is shown in **Figure 3-3**. The results in this figure are based on a scenario for a biomass cost of $50.00/dry ton and include barley straw, corn stover, oat straw, sorghum stubble, and wheat straw. Since corn and wheat are the most productive crops in the U.S., it is not surprising that the Midwest states make up the majority of states with the ability to produce over 1 million dry tons of biomass per year.

Figure 3-3: Projections of Agricultural Residues at $50/dry ton (ORNL, 2011)



The geographical distribution of agricultural residues described by the Update to the Billion Ton Study is supported by the results of other studies. The map shown in **Figure 3-4** is from the BEAM model (Enegis, 2011) and shows that agricultural residues are concentrated in the Midwest U.S. Similarly, the maps shown in **Figure 3-5** are from the USDA statistical services and also show high concentrations of agricultural residues in the Midwest U.S.

Figure 3-4: Total U.S. Agricultural Residues Modeled by BEAM (NETL, 2010a)

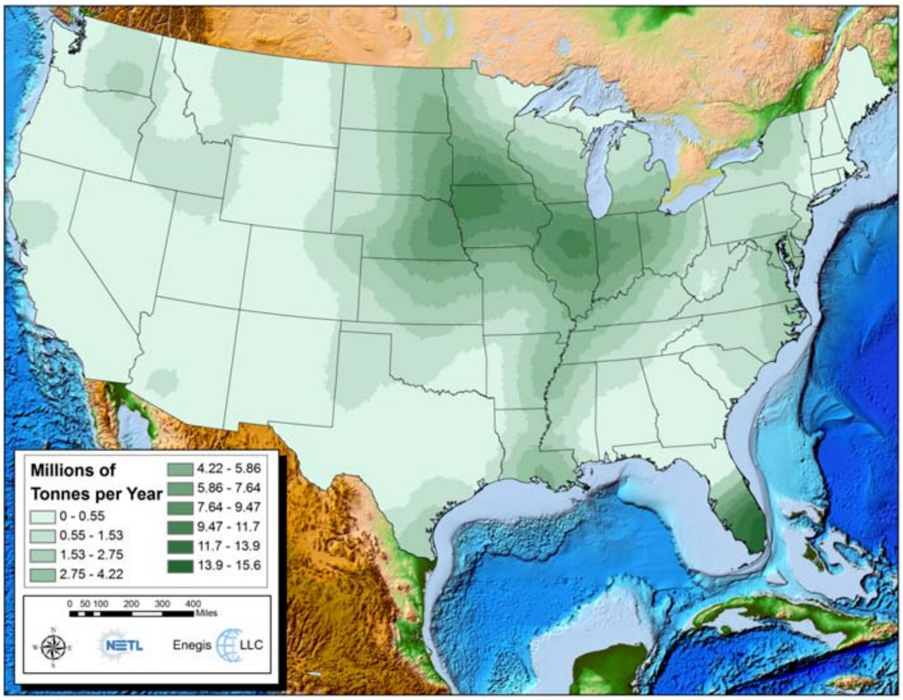
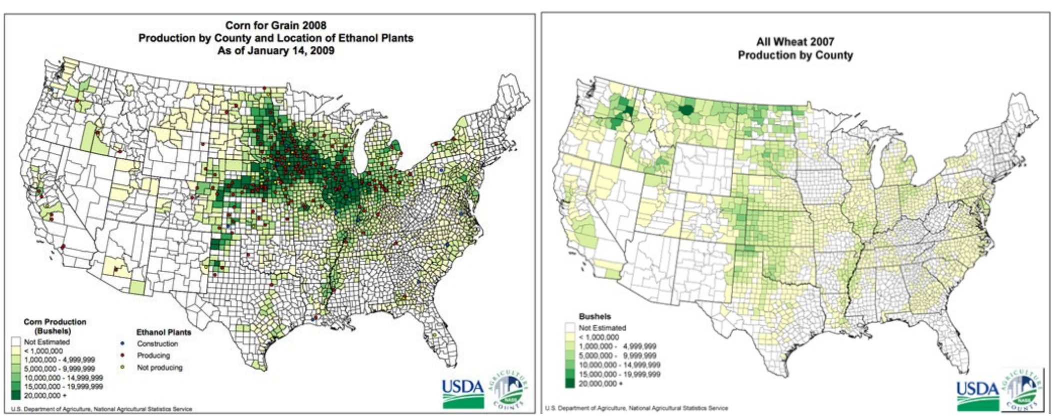


Figure 3-5: USDA Feedstock Density Maps for Corn Stover and Wheat Straw (USDA, 2011)



The results shown in **Figure 3-3** are representative of a cost scenario for $50.00/dry ton and are based on data published by Idaho National Laboratory in 2009. The cost of $50.00/dry ton accounts for the grower payment, harvesting and chipping, and storage, but does not account for transportation and subsequent steps in the supply chain. **Table 3-1** shows the costs for more steps of the supply chain, beginning with the grower payment and ending with the receipt and processing of crop residue at energy conversion facility. These cost data were originally developed for the conversion of lignocellulosic feedstocks to liquid fuels (Hess, Wright, Kenney, & Searcy, 2009) but are also applicable to the combustion of biomass to produce electricity.

Table 3-1: Biomass Delivery and Processing Costs

Supply Chain Segment	Details	Cost ($)
Grower Payment	Cost for nutrient replacement and organic matter loss plus a profit to the grower	$25.00
Harvesting and Baling	Capital and operating costs for harvesting equipment and baler	$18.39
Storage	Cost for skid, weather protection	$7.36
Transportation	Truck and fuel costs	$12.00
Receiving and Preprocessing	Bale breaking, size reduction, drying if needed	$14.27
Total Cost		**$77.02**

At $77 per delivered dry ton, biomass is more expensive on an energy basis than coal. In an operating environment without carbon constraints, the relatively high cost of biomass prevents it from being competitive with coal as a fuel for electricity production.

3.2.2 Forest Biomass Production

Most forest resources are used by the forest products industry, which is dominated by large producers such as Georgia Pacific and Weyerhaeuser, as well as thousands of small businesses that make paper and wood products. These producers add much more value to woody biomass than can be added by the energy sector; wood-to-paper conversion is more profitable than wood-to-fuel conversion.

In contrast to high-quality wood feedstocks, there is less competition for forest residues, making them a viable resource for power production. This includes logging residues generated during the harvesting of timber for conventional forest products. Logging residue consists of tree tops, branches and limbs, salvageable dead trees, non-commercial species, and small trees. Another source of forest residue is the biomass removed during forest thinning, a practice that improves the health of a forest and prevents forest fires.

The Updated Billion Ton Study used data from the Department of Energy's (DOE) Bioenergy Knowledge Discovery Framework (ORNL, 2011) to identify the top states for woody biomass production under cost scenarios of $50 and $100 per dry ton. These results include high-quality wood feedstocks as well as forest residues. A rule of thumb is that only 70 percent of woody biomass is used and the rest is available as residues (ORNL, 2011). Of the remaining 30 percent, it is estimated that 21 percent is from logging residues and the remainder is from thinning (ORNL, 2011). As with the analysis of agricultural residues presented above, these costs represent the grower payment, harvesting and chipping, and storage, but do not account for transportation and subsequent steps in the supply chain. At a roadside cost of $50 per dry ton, approximately 46 billion dry tons of woody biomass can be produced annually. At a roadside cost of $100 per dry ton, approximately 93 billion dry tons of woody biomass can be produced annually. **Figure 3-6** shows the results for the $50-per-dry-ton scenario, and **Figure 3-7** shows the results for the $100-per-dry-ton scenario.

Figure 3-6: Woody Biomass Production for Bioenergy at $50 per Dry Ton (Roadside)

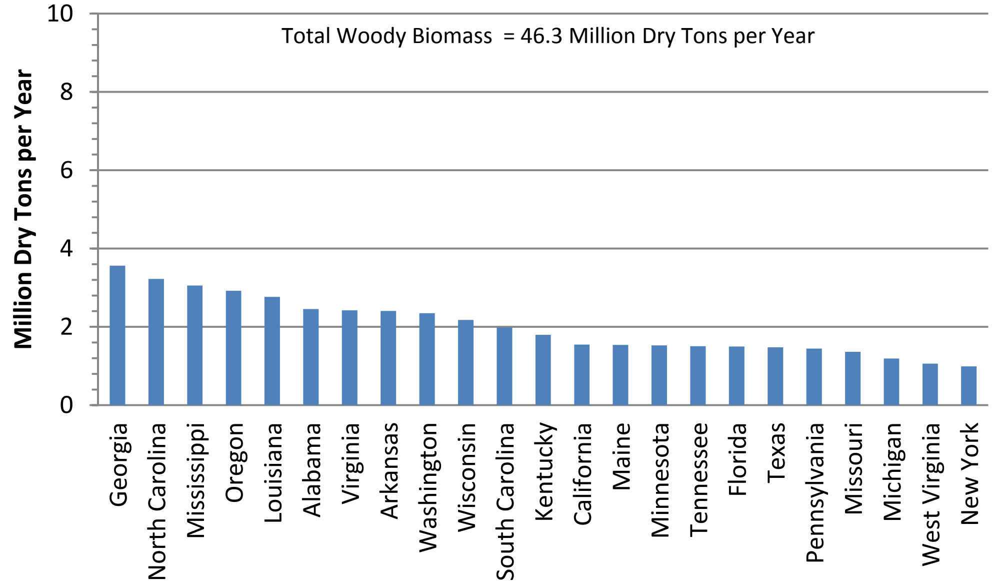
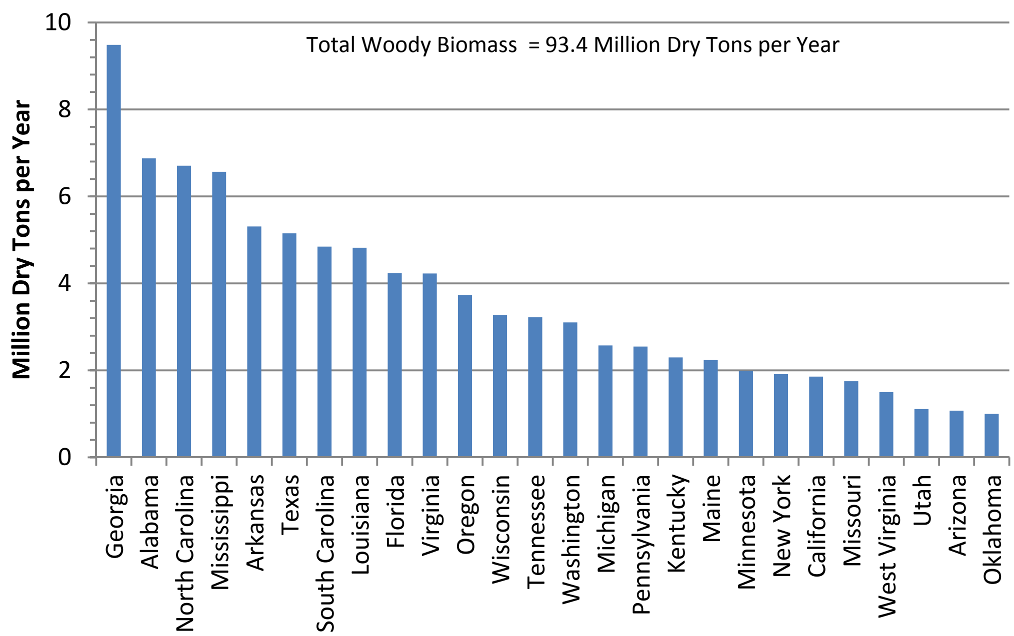


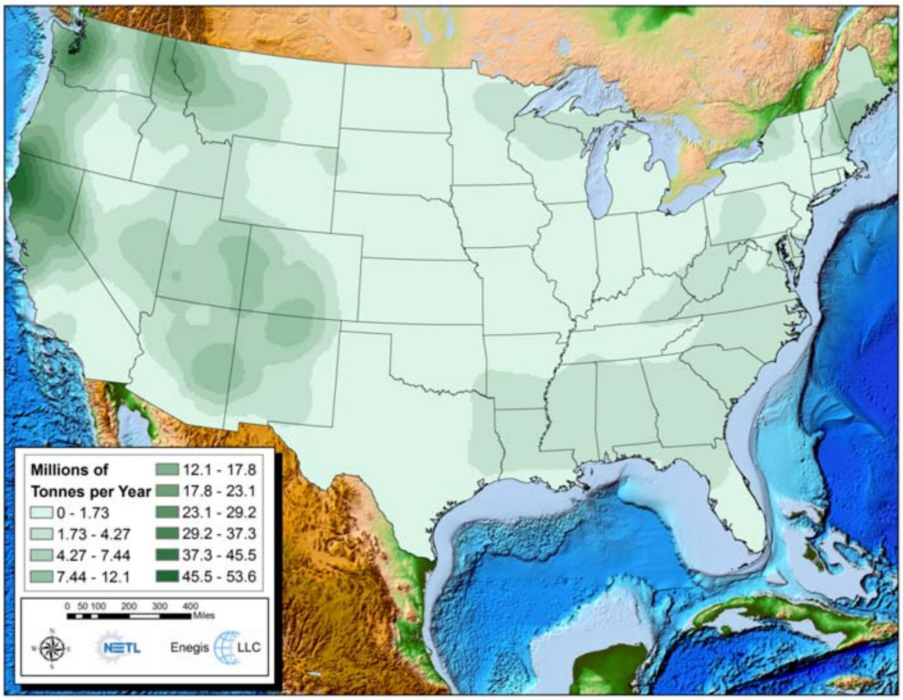
Figure 3-7: Woody Biomass Production for Bioenergy at $100 per Dry Ton (Roadside)



The above figures show that the Southeast states are the largest contributors to the resource base of woody biomass. The mid-Atlantic region (including Pennsylvania, West Virginia, and New York) and the Pacific Northwest are also key contributors to the resource base of woody biomass. The increase in the magnitude of the bars from **Figure 3-6** to **Figure 3-7** indicates that producers will develop more land for the production of woody biomass if the market price of biomass increases.

The BEAM model shows that most of the resource base for woody biomass is on the West Coast, as shown in **Figure 3-8**. While this may be true, much of it is either reserved or under contract to the forest products industry. This is also true for much of the area of the Rocky Mountains, although a recent infiltration of pine beetles has destroyed large areas of forestland that is in danger of burning if the biomass is not removed. The BEAM map shows a consistent concentration in the Southeast states that is consistent with the results presented by the Updated Billion Ton Study.

Figure 3-8: BEAM Forest Biomass Concentration Map (NETL, 2010a)



Similar to the case for agricultural residues, the cost of each piece of the supply chain must be examined to make sure the feedstock is affordable. Analogous to the case for agricultural residue, Idaho National Laboratory (INL) published a woody biomass design report that determined the cost at each stage of the supply chain (Hess, et al., 2009). Those costs were added to the estimated stumpage fee from the Updated Billion Ton Study. The stumpage fee is analogous to a grower payment and accounts for the costs of forest management and any payments made to land owners. Depending on the region and type of wood (hardwood or softwood), the stumpage fee can vary from $13.40 to $27.60 per dry ton. The variations in stumpage fees are shown according to wood type and region in **Table 3-2**.

Table 3-2: Regional and Wood-Specific Stumpage Fees (ORNL, 2011)

Wood Type and Region	Stumpage Fee - $/Green Ton	Stumpage Fee - $/Dry Ton
Hardwoods		
North	$7.70	$15.40
South	$6.70	$13.40
Softwoods		
North	$10.40	$20.80
South	$7.80	$15.60
West	$13.80	$27.60

The remaining costs for woody biomass delivery to the power plant are shown in **Table 3-3**.

Table 3-3: Delivered Costs of Woody Biomass

Supply Chain Segment	Cost ($)
Grower Payment (Stumpage Fee)	$15.00
Harvest and Collection	$3.06
Preprocessing	$6.57
Transportation	$15.80
Receiving and Handling	$2.67
Storage	$1.06
Total	**$44.16**

3.2.3 Energy Crop Production

Energy crops are categorized as either perennial herbaceous (with some annual herbaceous) or HPs. Both offer the potential of sustainable, consistent, high feedstock density biomass production on land that may not be suitable for primary crop production.

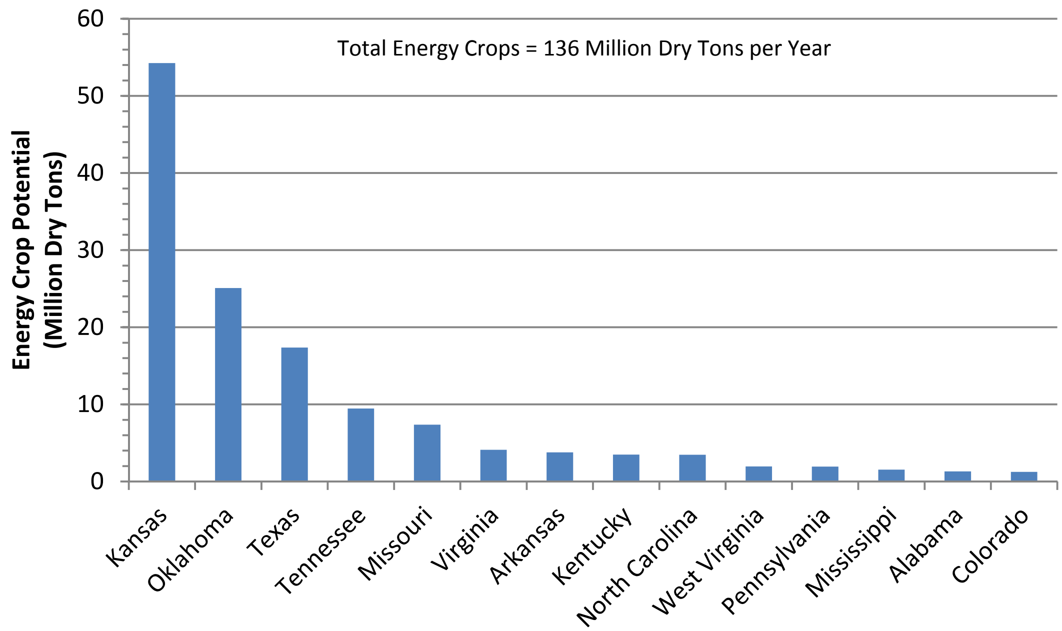
3.2.3.1 Herbaceous Energy Crops

Switchgrass is often used as the benchmark for herbaceous perennial energy crops and has been the focus of most of the research on herbaceous energy crops. Research on other varieties of herbaceous energy crops has shown that they may exhibit higher mass yields per acre that can provide significantly more biomass than previously estimated. For example, hybrid switchgrass, Big Bluestem, Miscanthus giganteus, and some cane varieties are yielding 10 to 18 dry tons per acre. Most of the herbaceous energy crops grow in the same climates so it is likely that the geographic distribution of herbaceous energy crops will not vary significantly among varieties.

An advantage of energy crops is that they will be grown on marginal lands and will not have competition from other agricultural products. The low costs of land development and potentially low fertilizer requirements of herbaceous energy crops will result in a low-cost feedstock.

The Updated Billion Ton Study uses POLYSIS to estimate the potential for energy crops. POLYSIS does not have current year scenarios for energy crops, but does have projections for a 2030 scenario. The POLYSIS results for a 2030 scenario with biomass costs of $50 per ton are shown in **Figure 3-9**.

Figure 3-9: Energy Crop Potential in 2030 at $50 per Dry Ton (Roadside Cost)



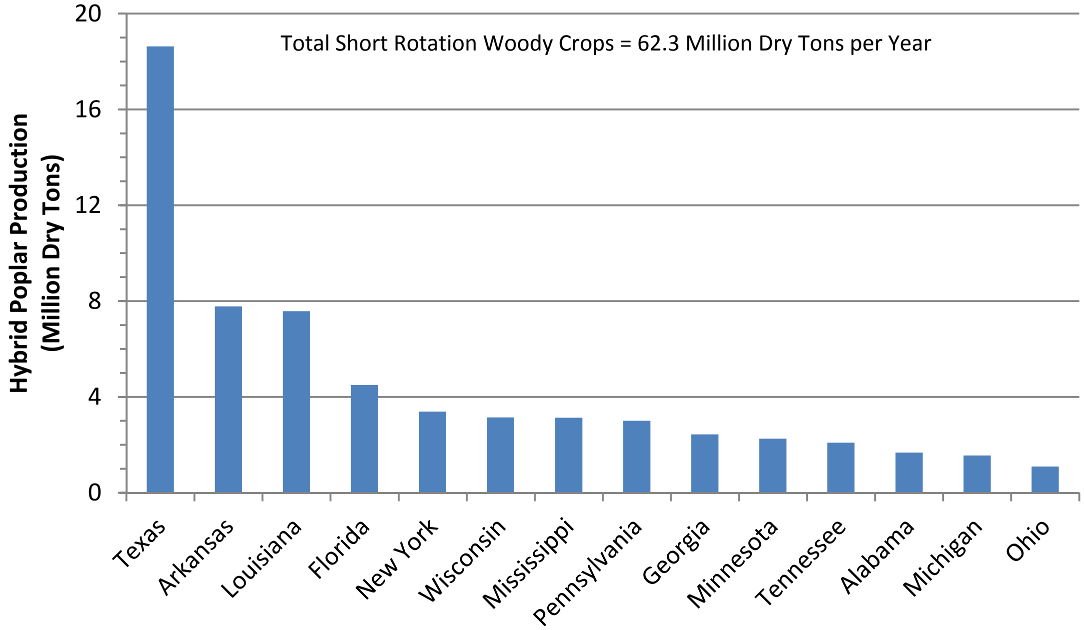
Kansas, Oklahoma, and Texas have enormous potential to grow switchgrass and other herbaceous energy crops. The Southeast and Mid-Atlantic states also show potential for the production of these crops.

Feedstock processing costs for herbaceous energy crops are assumed to be equivalent to those for agricultural residues, albeit with a much lower grower payment due to lower demands for soil nutrients and amendments, higher yields, and lower maintenance requirements.

3.2.3.2 Hybrid Poplar

HP can be grown in areas currently in forestland or where herbaceous energy crops can be grown. Poplar and Willow are the two most prevalent HPs. The genetic reproducibility and easy forest management requirements of poplar make it a desirable energy crop (ORNL, 2011), and shrub willows have the potential to be grown on marginal land as a dedicated energy crop across a large area of the U.S. (ORNL, 2011). The Update to the Billion Ton Study estimates an annual supply of 62.3 million dry tons of HP by 2030 (**Figure 3-10**).

Figure 3-10: Hybrid Poplar Production in 2030 at $50 per Dry Ton (Roadside Cost)

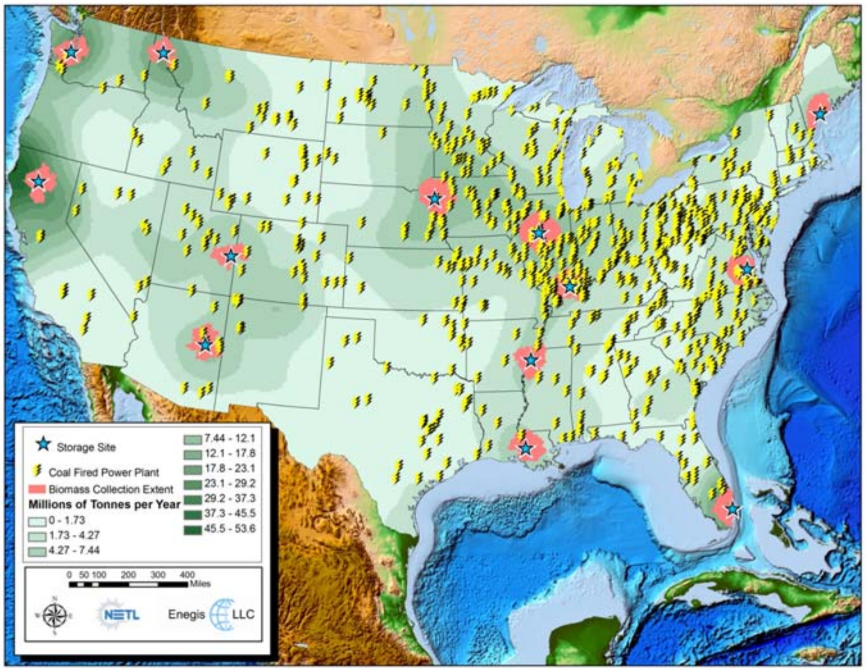


The states that can contribute over 1 million dry tons of HP per year are from multiple regions, including the upper Midwest, Southeast, Mid-South, and Mid-Atlantic states.

3.3 Proximity of Coal and Biomass Resources

The co-firing of biomass with coal will take place at an existing coal facility in most situations, and the proximity of biomass resources with respect to coal plants will play the largest role in whether or not a specific plant can choose co-firing to reduce emissions. The BEAM model (Enegis, 2011) analyzed biomass availability with respect to locations of coal plants in the U.S. When combined with the projected geography and density of energy crops (as shown above in **Figure 3-4** and **Figure 3-8**), there is considerable potential for co-firing in certain regions of the country. The proximity of biomass resources and coal-fired power plants, as calculated by the BEAM model, is shown in **Figure 3-11**.

Figure 3-11: Coal Plant and Biomass Resource Proximity Calculated by the BEAM Model (NETL, 2010a)



A closer look at **Figure 3-11** and the biomass concentrations from the Updated Billion Ton Study show that there is good potential for co-firing agricultural residues with coal plants in Iowa and Illinois. Although, in those states, there may be considerable competition for agricultural residues if biofuels mandates and incentives encourage the production of liquid fuels from cellulosic feedstocks.

Co-firing in the southeast, between the amount of forest resources and the potential for either herbaceous or woody energy crops, has considerable potential. With major waterways and railways in place, feedstock transportation costs can be lower, which allows for greater transportation distances to be achieved.

Conversely, several mid-Atlantic states with large coal resources and installed capacity of coal-fired facilities such as Ohio, Pennsylvania, West Virginia and New York lack an adequate agricultural and forest residues to support significant co-firing capacity. If the incentives for co-firing were large enough, however, co-firing could grow in these states because co-fired facilities would be able to compete with the forest products industry for standing timber.

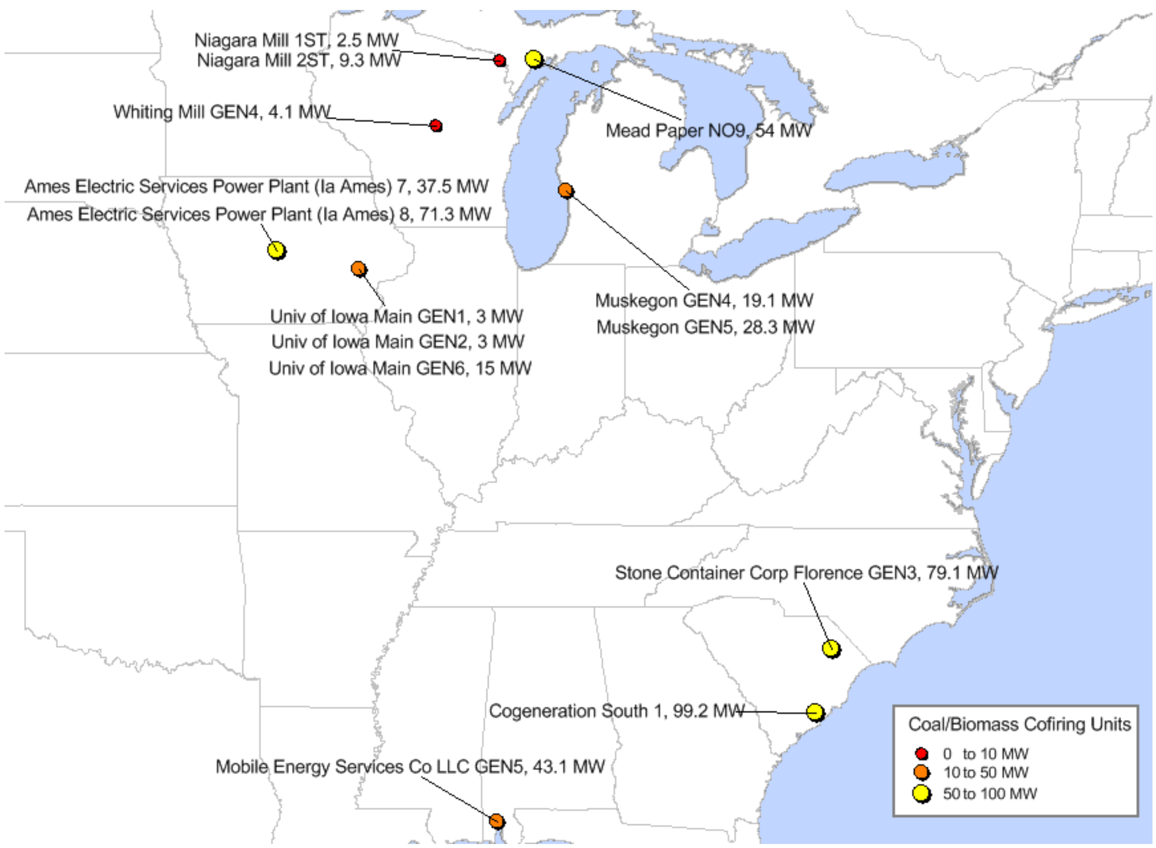
Large collection centers can act as large preprocessing centers. Pelleting, torrefaction, or other pretreatment processes can be used to increase the physical density, carbon density, or both. Torrefaction, if economical, can be performed at these large collection depots that not only increase carbon density but, combined with pelleting, also can give biomass both a physical and carbon density close to coal as well as provide the biomass with similar crushability and the ability to be stored outside indefinitely.

3.4 Growth of Co-firing

In 2010, the combustion of biomass accounted for 11.5 billion kWh of electricity generation (EIA, 2012), which is a value that includes biomass combustion in several forms, such as the operation of boilers designed to burn biomass exclusively or boilers that burn black liquor (a biomass byproduct of pulp and paper production). This analysis does not focus on dedicated biomass boilers, but focuses on the co-firing of coal and biomass. The co-firing of coal and biomass in the U.S. generated 1.36 billion kWh of electricity in 2010, representing a small share of renewable electricity generation (430 billion kWh) and an even smaller share of total electricity generation (3,998 billion kWh) (EIA, 2012).

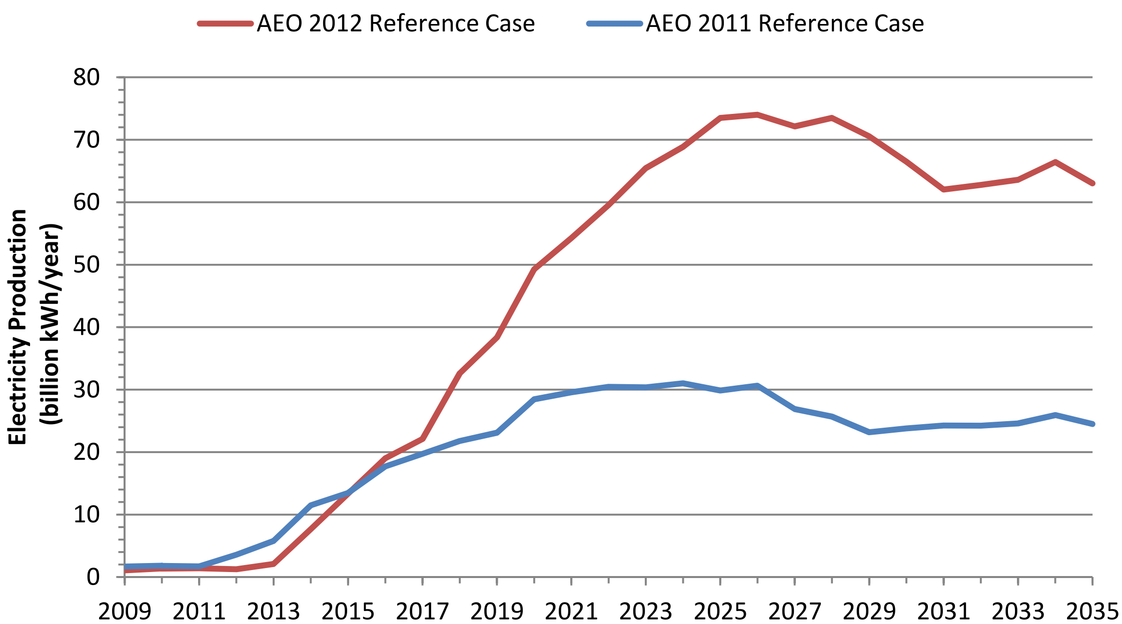
U.S. power plants that co-fire coal and solid biomass comprise 469 MW of installed capacity. As shown in **Figure 3-12**, these power plants are located in the Eastern U.S. and have single-boiler capacities ranging from 3 to 99 MW. These power plants include facilities in the electric power sector and the industrial sector. Pulp and paper mills, which have biomass waste streams that can be combusted for energy recovery, are an example of an industrial producer of co-fired power.

Figure 3-12: Facilities with Coal and Biomass Co-Firing in 2010



As shown by **Figure 3-13**, EIA's AEO Early Release for 2012 projects significant growth in coal and biomass co-firing (EIA, 2012). The 2011 reference case shows a peak of 31 billion kWh per year in 2024, and the 2012 reference case is even more aggressive, showing a peak of 74 billion kWh per year in 2026. These peaks are 22 to 53 times higher than current electricity generation levels. EIA's projected increase in biomass co-firing for electricity generation is driven by state RPS requirements that encourage the use of renewables and low-cost projections for biomass feedstocks.

Figure 3-13: EIA Reference Case Projections – Electricity Generation from Biomass Co-firing



The potential for near-term growth in coal and biomass co-firing is limited by the number of existing power plants that are capable of switching from coal-only feedstocks to a mix of coal and biomass. The U.S. currently has 5,080 MW of potential coal and biomass co-firing capacity (Ortiz, et al., 2011). This potential capacity was estimated by sorting EIA's database of power plants according to the boiler types listed in NETL's Coal Power Plant Database (Ortiz, et al., 2011).

If the potential expansion in coal and biomass co-fired capacity (5,080 MW) is added to the current capacity (469 MW), the U.S. could have a total coal and biomass co-firing capacity of 5,549 MW. This total capacity would be comprised solely from the conversion of existing facilities. To calculate the total electricity produced by these power plants, an average capacity factor must be known. A default capacity factor of 85 percent is used by the environmental and cost models of this analysis, but many power plants that are suitable for coal and biomass co-firing have lower capacity factors (Ortiz, et al., 2011). To match the peak production of 31 billion kWh per year (as projected by the AEO 2011 reference case) the potential co-firing capacity of 5,550 MW would require an average capacity factor of 64 percent. The peak production of 74 billion kWh (as projected by the AEO 2012 reference case) could not be achieved by the hypothetical fleet of 5,549 MW, which means that greenfield co-firing facilities would have to be constructed to attain such a production rate.

4 Environmental Analysis of Coal and Biomass Co-firing

A life cycle assessment (LCA) accounts for the material and energy flows of a system from cradle to grave. The cradle is defined as the extraction of resources from the earth and the grave is defined as the final use or disposition of products. The modeling completed herein builds upon NETL's previous LCA models with the addition of components specific to coal and biomass co-firing systems. The boundaries, assumptions, data, and modeling methods of this analysis are discussed below.

4.1 Scope and Boundaries

The boundaries of the LCA account for the cradle-to-grave energy and material flows for the co-firing of coal and biomass. The boundaries include five LC stages:

LC Stage #1: Raw Material Acquisition (RMA) includes the extraction of coal, and cultivation and harvesting of biomass. It begins with the extraction of resources from the earth and ends with biomass and coal ready for transport.

LC Stage #2: Raw Material Transport (RMT) includes transport of coal and biomass from the point of acquisition to the energy conversion facility. Coal is transported by rail and biomass is transported by truck.

LC Stage #3: Energy Conversion Facility (ECF) includes the operation of a power plant and any modifications necessary to process and co-fire biomass. The ECF has a PC boiler and a net output of 550 MW. Before combustion, biomass is ground into smaller pieces and is then dried. This stage also includes the retrofit of the power plant, which includes minor boiler modifications and the construction of biomass handling equipment.

LC Stage #4: Product Transport (PT) includes the transmission of electricity from the point of generation to the final consumer. There is a seven percent loss associated with transmission and distribution (T&D) of electricity (representative of the U.S. average electricity grid). The only emission associated with this stage is the sulfur hexafluoride (SF_6) that is released by transmission and distribution electrical equipment.

LC Stage #5: End Use represents the use of electricity by the consumer. No environmental burdens are incurred during this stage.

The use of a consistent functional unit establishes comparability among LCAs. The functional unit of this is the delivery of 1 MWh of electricity to the consumer. All results are expressed according to this functional unit.

4.2 Scenarios

Three scenarios are modeled in this analysis. The first scenario is a coal-only power plant that provides a basis for understanding the changes in environmental performance when co-firing is implemented. The second scenario is a co-fired power plant with a feedstock mix that is 10 percent biomass by energy. The third scenario is identical to the second scenario, except for its use of forest residue instead of HP. The boundaries of these scenarios are described below.

4.2.1 Combustion of Coal Only

This scenario models the combustion of Illinois No. 6 coal in a PC boiler (biomass is not combusted in this scenario). The coal feedstock is representative of Illinois No. 6 coal, which is transported by rail from the coal mine to the power plant. The PC boiler has a 33 percent efficiency, which is equivalent to a heat rate of 10,909 kJ/kWh (10,339 Btu/kWh). There is a seven percent transmission loss between the energy conversion facility and the consumer. The key unit processes and modeling network for this scenario are shown in **Figure 4-1**.

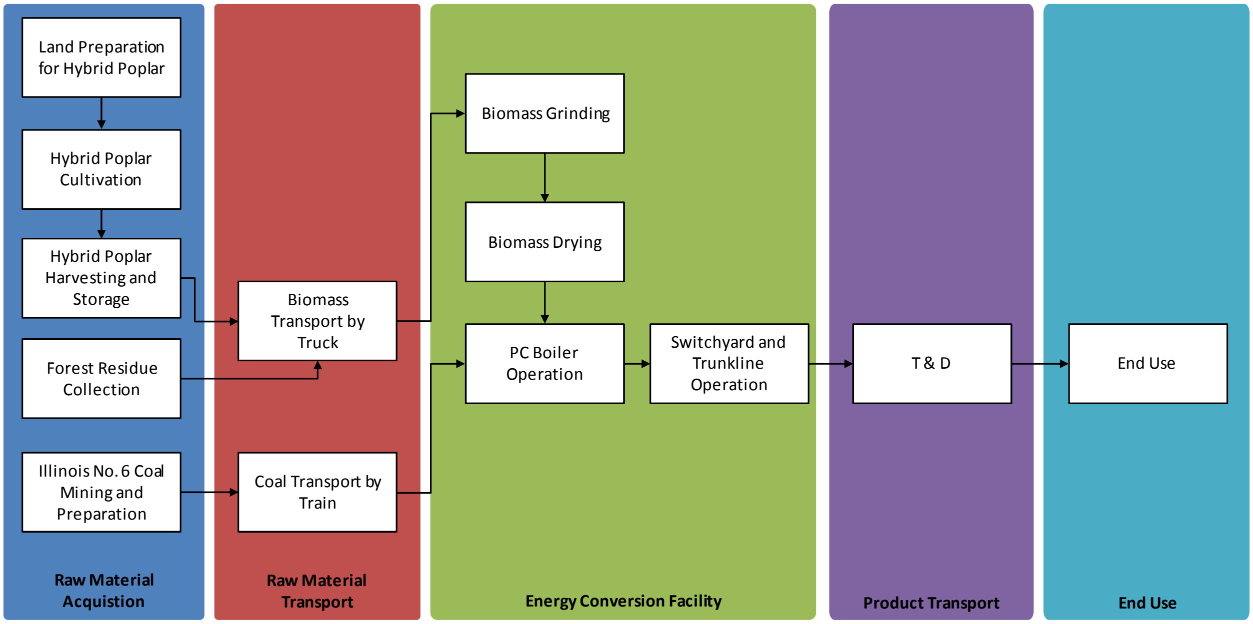
4.2.2 Co-firing of Coal and Hybrid Poplar

This scenario models the combustion of coal and biomass in an existing PC boiler. The coal feedstock is representative of Illinois No. 6 coal and the biomass feedstock is representative of HP (a dedicated energy crop). Coal is transported by rail and biomass is transported by truck. The biomass received at the gate of the energy conversion facility goes through grinding and drying processes before it is fed to the boiler. The boiler burns a fuel mix containing 10 percent biomass and 90 percent coal (on an energy basis). The boiler has a 32.8 percent efficiency, which accounts for a slight efficiency loss caused by co-firing of biomass and is equivalent to a heat rate of 10,980 kJ/kWh (10,340 Btu/kWh). There is a seven percent transmission loss between the energy conversion facility and the consumer. The key unit processes and modeling network for this scenario are shown in **Figure 4-1**.

4.2.3 Co-firing of Coal and Forest Residue

This scenario is identical to the co-firing of coal and HP, except for its use of forest residue instead of HP. Unlike HP, forest residue is a byproduct of another industry and does not require land preparation or cultivation. The physical properties of forest residue are similar to those for HP, so the performance of the energy conversion facility is the same regardless of the choice to use HP or forest residue. There is a seven percent transmission loss between the energy conversion facility and the consumer. The key unit processes and modeling network for this scenario are shown in **Figure 4-1**.

Figure 4-1: Primary Unit Process Network for LCA of Co-fired Power with Coal and Biomass



4.3 Data Sources

An LCA model includes processes that are directly related to the supply chain of interest, as well as ancillary processes that represent a relatively small contribution to the system. Land use areas and associated GHG emissions were quantified outside of GaBi using a separate spreadsheet model. The key unit processes of this analysis are shown in the above flow diagram (**Figure 4-1**) and are summarized in **Table 4-1** below.

Table 4-1: Key Unit Processes for LCA of Coal and Biomass Co-firing

Life Cycle Stage	Unit Processes
LC Stage #1: Raw Material Acquisition	Coal Mining (Illinois No. 6 Coal) HP Land Preparation HP Cultivation HP Harvesting Forest Residue Collection
LC Stage #2: Raw Material Transport	Coal Transport by Train Biomass Transport by Truck
LC Stage #3: Energy Conversion Facility	Biomass Grinding Biomass Drying PC Boiler Operation Switchyard and Trunkline Operation
LC Stage #4: Product Transport	Electricity Transmission and Distribution
LC Stage #5: End Use	N/A

The data sources, scope, and boundaries of each unit process are provided below.

4.3.1 Coal Mining

Illinois No. 6 coal is part of the Herrin Coal. It is a bituminous coal that is found in seams that typically range from about 2 to 15 feet in thickness and is found in the southern and eastern regions of Illinois and surrounding areas. Illinois No. 6 coal is commonly extracted via underground mining techniques, including continuous mining and longwall mining. Illinois No. 6 coal seams may contain relatively high levels of mineral sediments or other materials and require coal cleaning (beneficiation) at the mine site.

Operations of the coal mine were modeled based on operation of the Galatia Mine, which is operated by the American Coal Company and located in Saline County, Illinois. Sources reviewed in support of coal mine operations include Galatia Mine production rates, electricity usage, particulate emissions, methane emissions, wastewater discharge permit monitoring reports, and communications with Galatia Mine staff. When data from the Galatia Mine were not available, surrogate data were taken from other underground mines.

During the acquisition of Illinois No. 6 coal, methane is released during both the underground coal extraction and the post-mining coal preparation activities. Illinois No. 6 coal seams are not nearly as thick as Powder River Basin coals, and as a result are less commonly utilized as a resource for coal-bed methane extraction. Instead, methane capture may be applied during the coal extraction process. Based on recent data available from the Environmental Protection Agency (EPA), coal bed methane emissions for underground mining, including mining within the Illinois No. 6 coal seam, are expected to range from 360 to 500 scf/ton of produced coal with an expected value of 422 scf/ton (EPA, 2011). In this analysis, methane capture is not used for Illinois No. 6 coal.

4.3.2 Hybrid Poplar Land Preparation

The preparation of land for HP begins with farming activities to prepare land area and ends with a unit of land area ready for seeding. Land preparation occurs once during the study period. Operations for the preparation of land for HP production are based on the estimated diesel consumption of farming equipment, the direct emissions from diesel combustion, fugitive dust emissions caused by surface dust that is disturbed by land preparation equipment, and the annual yield rate of HP.

4.3.3 Hybrid Poplar Cultivation

The cultivation of HP includes the use of farm equipment, fertilizer, and air emissions associated with the maintenance of an HP crop. Inputs to this process include the amount of diesel consumed by farm equipment; nitrogen, phosphorus, and potassium (NPK) fertilizer; herbicides; and irrigation water. Outputs from this process include emissions from the combustion of diesel used in farm equipment, PM emissions from land disturbance, and runoff water.

4.3.4 Hybrid Poplar Harvesting

The harvesting of HP includes the use of farm equipment. The key input to this process is diesel, which is used as fuel for crop harvesting equipment (a tree harvester). The air emissions from diesel combustion are accounted for in this process. Fugitive dust from biomass removal and land disturbance is categorized as PM emissions to air. Water use and emissions to water are not characterized in this process, because they are assumed to compose a negligible contribution to HP harvesting operations.

4.3.5 Forest Residue Collection

Forest residue is a byproduct of the forest products industry. A dedicated energy crop (e.g., HP) includes land preparation and cultivation activities prior to harvesting, but the acquisition of forest residue only includes biomass collection processes. The collection of forest residue uses the same data that is used for HP harvesting, which includes the construction and use of heavy equipment and associated diesel combustion.

4.3.6 Coal Transport by Train

Illinois No. 6 coal is transported by train from the coal mine to the power plant. This analysis defines a train as 1 locomotive pulling 100 railcars loaded with coal. The locomotive is powered by a 4,400 horsepower diesel engine (GE, 2008) and each car has a 100-ton coal capacity (NETL, 2010b).

GHG emissions for train transport are evaluated based on typical diesel combustion emissions for a locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive dust emissions. Loss during loading at the mine is assumed to be included in the coal reject rate; no loss is assumed during unloading. The railway connecting the coal mine and the energy conversion facility is existing infrastructure.

4.3.7 Biomass Transport by Truck

Biomass is transported by a combination truck with a trailer that is designed to hold chipped biomass. The truck and trailer combination is classified to have more than 60,000 lbs of gross vehicle weight. The truck is assumed to be loaded to capacity on the initial haul to the energy conversion facility and to return empty to the biomass site. The truck uses conventional diesel fuel.

4.3.8 Biomass Grinding

The model includes separate unit processes for biomass grinding, drying, and torrefaction, where grinding is completed prior to drying or torrefaction. Biomass drying is not applied to biomass that will be torrefied, as drying occurs during the torrefaction process. Biomass arrives at the energy conversion facility as chipped HP biomass. Tub grinders are used for grinding woody biomass and require an average of 360 kJ of energy per kg of biomass (Ciolkosz & Wallace, 2011).

4.3.9 Biomass Drying

Biomass drying is necessary to remove water from raw biomass, which has a moisture content ranging from 5 to 50 percent when delivered to the power plant. Natural gas is the sole source of heat energy used for biomass drying; therefore, energy use for biomass drying is limited to the consumption of natural gas. Other energy requirements, such as electricity or diesel fuel, required for loading and biomass handling, or process requirements, such as conveyors and other electrically powered processes, are assumed to be negligible and are not accounted for in this analysis.

4.3.10 PC Boiler Operation

The energy conversion facility is an existing 550 MW facility with a pulverized coal (PC) boiler that can be retrofitted to burn both coal and biomass. PC boilers are the prevalent combustion technology for coal-fired power and represent the most potential, in terms of total installed capacity, for coal-biomass combustion. The efficiency of the coal-only power plant is 33.0 percent, which is equivalent to a heat rate of 10,909 kJ/kWh and coincides with the average efficiency of U.S. baseload coal-fired power plants. The co-firing scenario is based on a feedstock input with 10 percent biomass by energy. There is a slight decrease in efficiency when biomass is introduced to the system; the plant efficiency of the co-fired scenario is 32.8 percent (10,985 kJ/kWh). The power plant has an FGD unit that removes 98 percent of the SO_2 emissions in the flue gas. The power plant also has an ESP unit that removes particulate matter. More details on the environmental performance of the PC boiler are provided in **Section 2**.

The power plant is an existing facility. New construction is not necessary for the coal-only scenario. The co-firing scenario requires minor boiler modifications and the addition of biomass handling equipment.

4.3.11 Switchyard and Trunkline Construction

The switchyard and trunkline are the interface between the power plant and the electricity grid and consist of electrical equipment (transformers and circuit breakers), conductive cables, and steel towers. The trunkline is 80 kilometers (50 miles) long. The data for the construction of the switchyard and trunkline account for the mass of concrete and metal construction materials.

4.3.12 Switchyard and Trunkline Operation

The operation of the switchyard and trunkline releases SF_6. SF_6 is a gas used for insulating electrical equipment and is lost due to leaks in equipment. Other than SF_6 emissions, this analysis does not account for other environmental burdens from the operation of a switchyard and trunkline.

4.3.13 Electricity Transmission and Distribution

The only unit process of LC Stage #4 is the transmission and distribution of electricity. This stage incurs a 7 percent loss of electricity. The emission of SF_6 from leaks in electrical equipment is also accounted for in this stage. The construction of electricity transmission and distribution equipment is not modeled in this analysis because it is existing infrastructure.

4.4 Land Use Change

Analysis of land use effects is considered a central component of an LCA under both the International Standards Organization (ISO) 14044 and the American Society for Testing and Materials (ASTM) standards. Additionally, the EPA’s Renewable Fuel Standard Program (RFS) (EPA, 2010) includes a method for assessing land use change and associated GHG emissions. The land use model of this analysis is consistent with this method. It quantifies both the area of land changed, as well as the GHG emissions associated with that change, for direct and select indirect land use impacts.

4.4.1 Definition of Direct and Indirect Impacts

Land use effects can be roughly divided into direct and indirect. In the context of this study, direct land use effects occur as a result of processes within the natural gas LC boundary. Direct land use change is determined by tracking the change from an existing land use type (native vegetation or agricultural lands) to a new land use that supports production; examples include gas wells, regasification facilities, biomass feedstock cropping, and energy conversion facilities.

Indirect land use effects are changes in land use that occur as a result of the direct land use effects. For instance, if the direct effect is the conversion of agricultural land to land used for energy production, an indirect effect might be the conversion to new farmland of native vegetation, but at a remote location, in order to meet ongoing food supply/demand. This specific case of indirect land use change has been studied in detail by the EPA (EPA, 2010) and other investigators, and sufficient data are available to enable consideration of this specific case of indirect land use within this study. There are also other types of indirect land use change that could potentially occur as a result of the installation of new energy production and conversion facilities. For instance, the installation of a new power plant at a rural location could result in the migration of power plant employees to the site, causing increased urbanization in surrounding areas. However, due to the uncertainty in predicting and quantifying this and other less studied indirect effects, such phenomena were not considered in this analysis.

4.4.2 Land Use Metrics

A variety of land use metrics that seek to numerically quantify changes in land use have been devised in support of LCAs. Two common metrics in support of an LCA are transformed land area (square meters of land transformed) and GHG emissions (kg CO_2e). The transformed land area metric estimates the area of land that is altered from a reference state, while the GHG metric quantifies the amount of carbon emitted in association with that change. **Table 4-2** summarizes the land use metrics included in this analysis.

Table 4-2: Primary Land Use Metrics

Metric Title	Description	Units	Type of Impact
Transformed Land Area	Area of land that is altered from its original state to a transformed state during construction and operation of the advanced energy conversion facilities	m^2 (acres)	Direct and Indirect
Greenhouse Gas Emissions	Emissions of GHGs associated with land clearing/transformation, including emissions from aboveground biomass, belowground biomass, soil organic matter, and lost forest sequestration	kg CO_2e (lbs. CO_2e)	Direct and Indirect

This assessment of GHG emissions from land use change includes those emissions that would result from the direct and indirect activities associated with the following:

- Quantity of GHGs emitted due to biomass clearing during construction of each facility
- Quantity of GHGs emitted due to oxidation of soil carbon and underground biomass following land transformation, for each facility
- Evaluation of ongoing carbon sequestration that would have occurred under existing conditions, but did not occur under study/transformed land use conditions

Additional land use metrics, such as potential damage to ecosystems or species, water quality changes, changes in human population densities, quantification of land quality (e.g., farmland quality), and many other land use metrics may conceivably be included in the land use analysis of an LCA. However, much of the data needed to support accurate analysis of these metrics are severely limited in availability (Bauer, Dubreuil, & Gaillard, 2007; Scholz, 2007), or otherwise outside the scope of this study. Therefore, only transformed land area and GHG emissions are quantified for this study.

4.4.3 Land Use Calculation Method

As discussed previously, the land use metrics that will be used for this analysis quantify the land area that is transformed from its original state due to production of electricity, including supporting facilities. Calculations are based on a 30-year study period, or as relevant for each facility as discussed in the following text.

4.4.3.1 Transformed Land Area

The transformed-land area metric was assessed using satellite imagery, aerial photographs, reported land use areas, biomass production yields, and other available data for each of the facilities considered within this study in order to assess and quantify the area of original-state land use for agriculture, forest, or grassland. Urban, residential, and other land uses were assumed to be avoided during the siting of each facility. Assumed facility locations and sizes are shown in **Table 4-3**. The facility sizes, coal and biomass feed rates, biomass yields, and locations used elsewhere in this LCA were incorporated into the land-transformed metric for consistency.

For the cases presented in this study, only LC Stage #1 includes installation of facilities in support of the coal-biomass co-firing electricity generation pathway. Other facilities, including the energy conversion facility, switchyard and trunkline, and transmission lines are existing infrastructures that do not incur land use change within the boundaries of this analysis. Additional equipment is installed at the energy conversion facility (LC Stage #3) when converting to co-firing. However, this new equipment is located within the energy conversion facility's existing footprint and does not cause a change in land use.

Table 4-3: Land Sites for Coal and Biomass Acquisition

LC Stage	Facility	Location
LC Stage #1	Illinois No. 6 Coal Mine	Southern Illinois
LC Stage #1	Hybrid Poplar Production	U.S. Midwest
LC Stage #1	Forest Residue Acquisition	No Land Use Change
LC Stage #2	Road and Rail Infrastructure	No Land Use Change
LC Stage #3	Energy Conversion Facility	No Land Use Change
LC Stage #4	Transmission and Distribution Infrastructure	No Land Use Change
LC Stage #5	Consumer Use	No Land Use Change

Transformed-land area, as well as the type of existing land use, was evaluated using aerial photographs for coal mining operations. Transformed land area for agricultural production of biomass was evaluated based on annual biomass production yield values, such that sufficient land area was ascribed to biomass production in order to meet demand for biomass from the energy conversion facility. Thus, the total area of transformed-land area required for biomass production varies by case, based on the total mass of biomass needed. Average land uses for agricultural biomass production, along with statewide or regional average land uses as identified by the USDA (2005), were selected for consistency with other collaborative work completed by NETL and the U.S.

Air Force.[1] Residual biomass production was assumed to result in no direct land use change, because residual biomass would be sourced from existing facilities and would not require the construction of new facilities or new biomass production. For all cases, transport of biomass was assumed to be by truck along existing roadways and therefore would not result in transformed-land area.

For indirect land use change, consistent with EPA's RFS2 analysis, it was assumed that 30 percent of all agricultural land that was lost as a result of the installation of facilities within the study resulted in the creation of new agricultural land. The creation of new agricultural land, in turn, was assumed to result in the conversion of either forest or grassland/pasture to farmland, according to regional land use characteristics identified by the USDA (2005).

4.4.3.2 Greenhouse Gas Emissions

GHG emissions due to land use change were evaluated based on the EPA's method for the quantification of GHG emissions, in support of RFS2 (EPA, 2010). EPA's analysis quantifies GHG emissions that are expected to result from land use changes from forest, grassland, savanna, shrubland, wetland, perennial, or mixed land use types to agricultural cropland, grassland, savanna, or perennial land use types. Relying on an evaluation of historic land use change completed by Winrock, EPA calculated a series of GHG emission factors for the following criteria: change in biomass carbon stocks, lost forest sequestration, annual soil carbon flux, methane emissions, nitrous oxide emissions, annual peat emissions, and fire emissions that would result from land conversion over a range of timeframes. EPA's analysis also included calculated reversion factors, for the reversion of land use from agricultural cropland, grassland, savanna, and perennial, to forest, grassland, savanna, shrub, wetland, perennial, or mixed land uses. Emission factors considered for reversion were changes in biomass carbon stocks, changes in soil carbon stocks, and annual soil carbon uptake over a variety of timeframes. Each of these emission factors, for land conversion and reversion, was included for a total of 756 countries and regions within countries, including the 48 contiguous states.

Based on the land use categories (forest, grassland, and agriculture/cropland) that were affected by study facilities, EPA's emission factors were applied on a statewide or regional basis. Only land conversion factors were considered for study facilities. For a more extensive review of the methods used to evaluate GHG emissions from land use change used by EPA for RFS2, please refer to the EPA documentation (EPA, 2010).

GHG emissions from indirect land use were quantified only for the displacement of agriculture and not for the displacement of other land uses. Indirect land use GHG emissions were calculated based on estimated indirect land transformation values, as discussed previously. Then, EPA's GHG emission factors for land use conversion were applied to the indirect land transformation values, according to transformed-land type and region, and total indirect land use GHG emissions were calculated.

[1] Existing land use types for agricultural production are consistent with the Aviation Fuel Life Cycle Assessment Working Group's *Life Cycle Greenhouse Gas Analysis of Advanced Jet Propulsion Fuels: Fischer-Tropsch Based SPK-1 Case Study (Final Report)*, currently in press.

4.5 LCA Results

The LCA results are presented according to the scenarios described in **Section 4.3**. These scenarios are as follows:

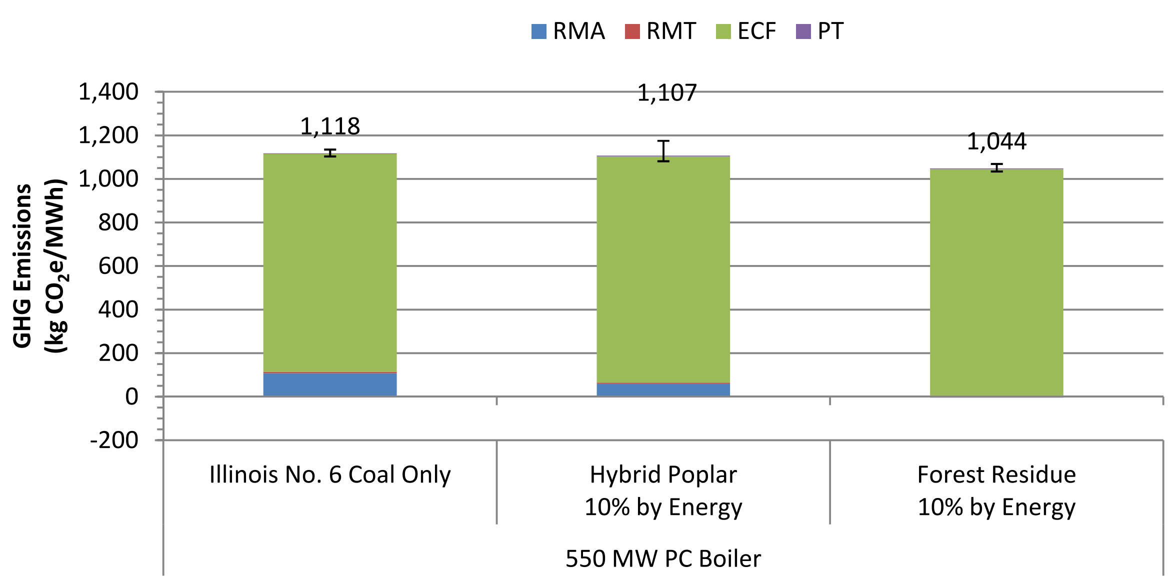
- 100 Percent Coal Combustion in a PC Boiler
- Co-firing of Coal and HP in a PC Boiler
- Co-firing of Coal and Forest Residue in a PC Boiler

The results of this analysis are shown on the basis of 1 MWh of electricity delivered to the consumer. Key results for air emissions, water use, and EROI are presented below. A comprehensive table showing results for other environmental metrics is provided in **Appendix C.**

4.5.1 Greenhouse Gas Emissions

This analysis expresses GHG emissions in terms of carbon dioxide equivalents (CO_2e) as established by the 2007 IPCC 100-year global warming potentials (GWP). The GWPs convert methane (CH_4), nitrous oxide (N_2O), and SF_6 to the basis of CO_2e; on a 100-year time frame, the GWPs are 25, 298, and 22,800 for CH_4, N_2O, and SF_6, respectively. The GHG results for the three scenarios of this analysis are shown by LC stage in **Figure 4-2**.

Figure 4-2: GHG Results for Power Generation from Coal and Biomass



The LC GHG emissions for the three scenarios range from 1,044 to 1,118 kg CO2e/MWh. The expected result for the co-firing of HP is one percent lower than the base scenario (100 percent coal combustion); however, due to uncertainties in biomass yields and coal mine methane emissions, there is an overlap between the uncertainty ranges of these two scenarios. The co-firing of forest residue has the lowest GHG emissions of this analysis because the acquisition of forest residue has relatively low GHG emissions from fuel combustion and does not incur GHG emissions from land transformation. The GHG emissions for each scenario are shown in more detail in **Figure 4-3**, **Figure 4-4**, and **Figure 4-5**.

Figure 4-3: Process-Level GHG Emissions for 100% Coal Co-firing

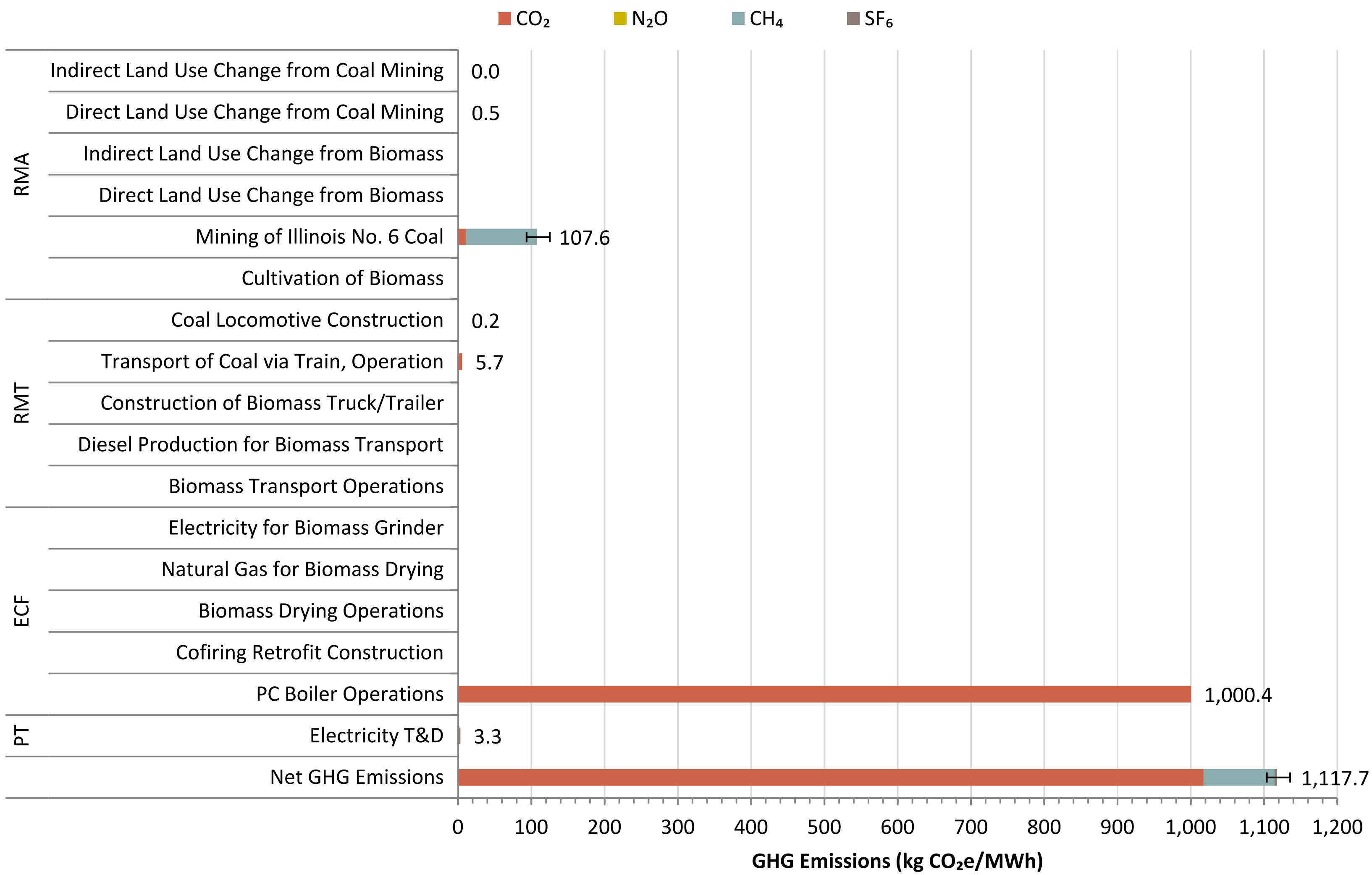


Figure 4-4: Process-Level GHG Emissions for Coal and 10% Hybrid Poplar Co-firing

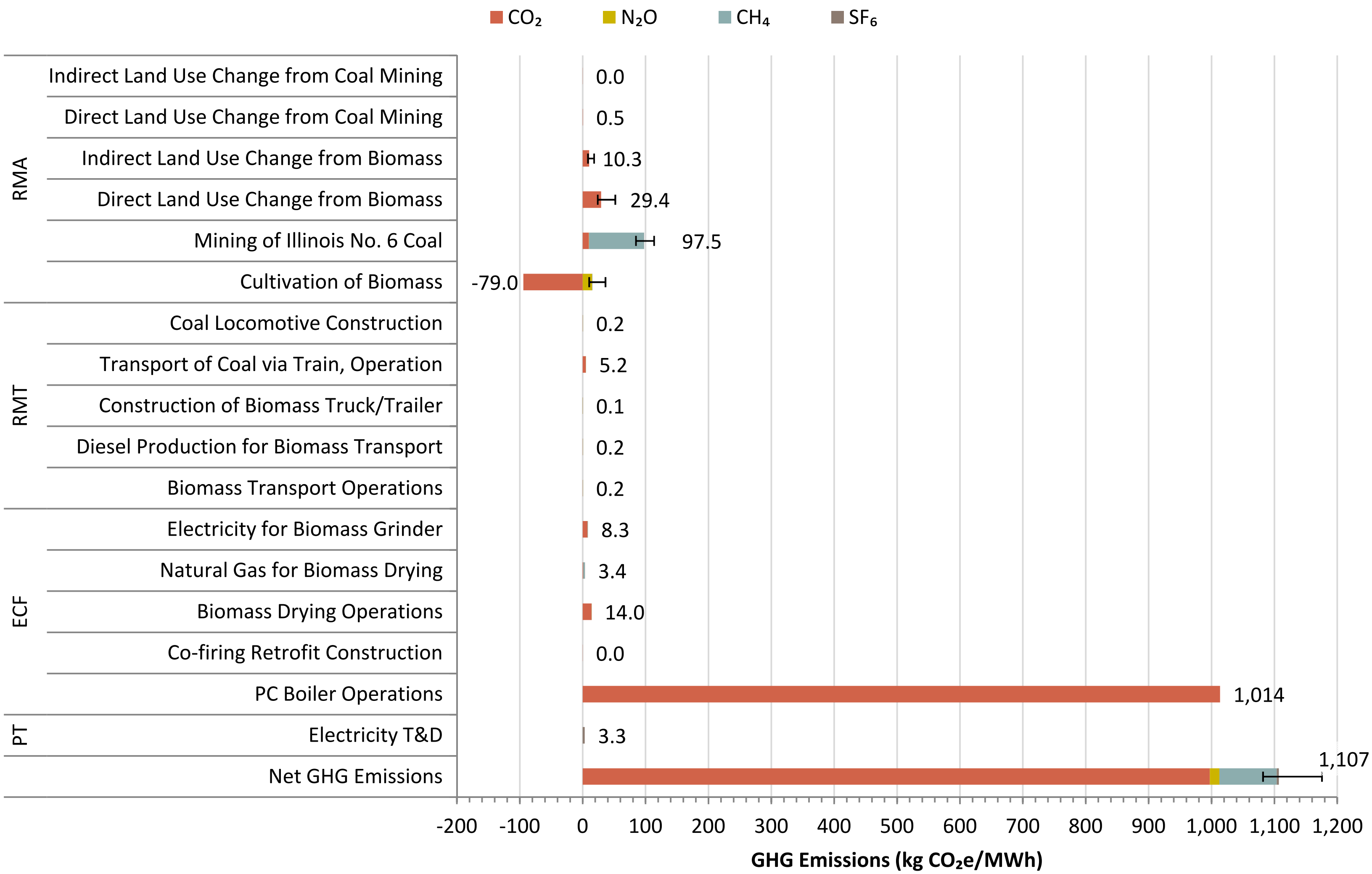
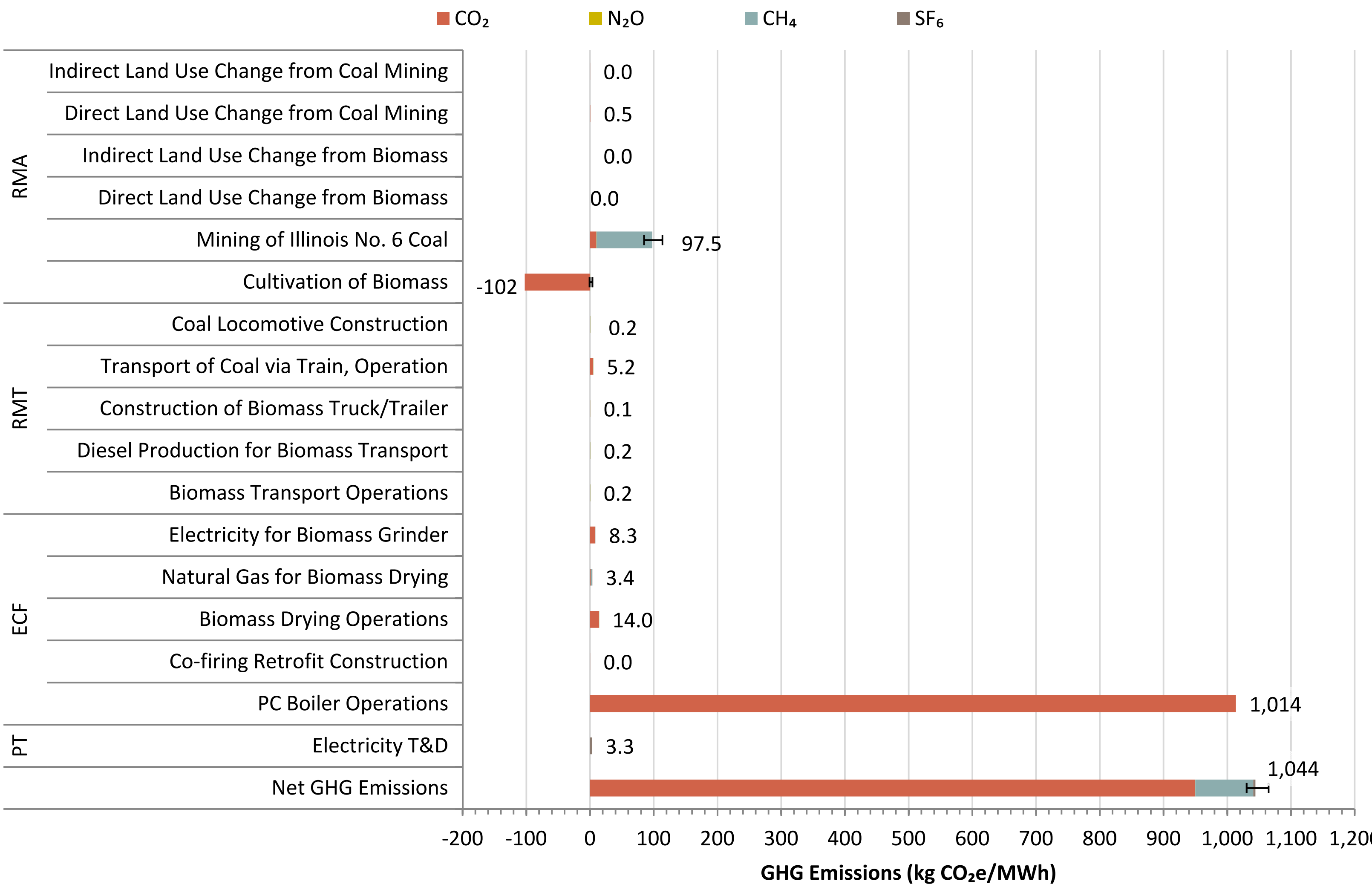


Figure 4-5: Process-Level GHG Emissions for Coal and 10% Forest Residue Co-firing



As shown by **Figure 4-3** through **Figure 4-5**, the majority of GHG emissions occur during PC boiler operations. For the co-firing cases (shown in **Figure 4-4** and **Figure 4-5**), a portion of the CO_2 emissions from PC boiler operations includes biogenic CO_2 that was absorbed during biomass cultivation.

Direct land use GHG emissions are produced when land is transformed from one use to another, and indirect land use GHG emissions occur when such a transformation also displaces agriculture. The co-firing of HP has the highest land use emissions due to the land that is transformed when planting a dedicated energy crop. The total direct and indirect land use emissions for the co-firing of HP are 39.7 kg CO_2e/MWh and represent 3.6 percent of the net GHG emissions of the scenario. The other scenarios do not have significant land use GHG emissions. The mining of coal incurs minor land use burdens and the acquisition of forest residue does not involve any land use transformation.

The mining of Illinois No. 6 coal produces 108 kg of CO_2e/MWh for the coal-only scenario (**Figure 4-3**) and 97.5 kg CO_2e/MWh for the two co-firing scenarios (shown in **Figure 4-4** and **Figure 4-5**). These coal mine emissions are comprised mostly of methane. Methane is released from coal seams during the mining of coal, and Illinois No. 6 coal in particular has relatively high methane emissions.

The co-firing of HP is unique because it produces significant N_2O emissions during biomass cultivation (shown in **Figure 4-4**). HP is a dedicated energy crop that uses fertilizer; the production and use of fertilizer produces significant N_2O emissions.

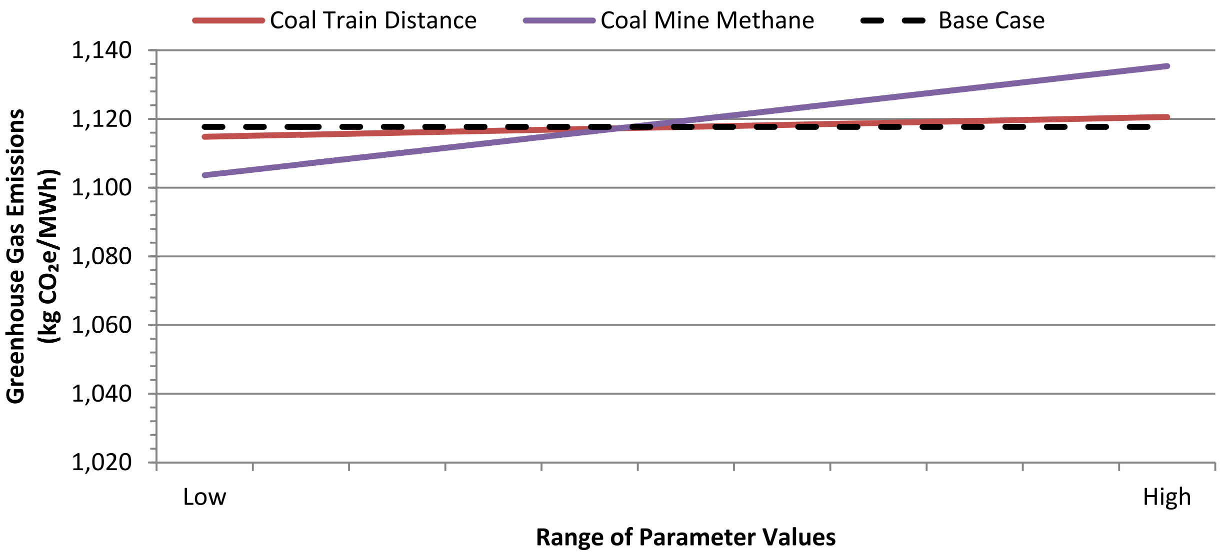
A series of modeling runs was conducted to evaluate the sensitivity of the GHG results to changes in key modeling parameters. The key modeling parameters for the coal-only scenario are the emission factor for coal mine methane and the distance of rail transport. The other scenarios have more variability; yield rates, biomass transport distances, and land use emission factors are key biomass parameters in addition to the coal-specific parameters. The values for these parameters are shown in **Table 4-4**, which includes low, expected values, and high values. **Table 4-4** shows values in English and SI units; all results in this report are provided in SI units, but some parameters (e.g., coal mine methane emissions) are usually discussed in English units.

Table 4-4: Uncertainty Ranges for Key Environmental Modeling Parameters

Scenario	Parameter	Low	Expected Value	High
100% Coal	Coal Train Distance, mi.	200	400	600
	Coal Mine Methane, scf/ton	360	422	500
10% Hybrid Poplar	Biomass Truck Distance, mi.	10	50	200
	Coal Train Distance, mi.	200	400	600
	Biomass Yield, lb./acre-yr.	7,751	13,700	16,799
	Coal Mine Methane, scf/ton	360	422	500
	Direct Land Use, lb. CO_2e/lb.	0.215	0.264	0.466
	Indirect Land Use, lb. CO_2e/lb.	0.0755	0.0925	0.164
10% Forest Residue	Biomass Truck Distance, mi.	10	50	200
	Coal Train Distance, mi.	200	400	600
	Biomass Yield, lb./acre-yr.	7,751	13,700	16,799
	Coal Mine Methane, scf/ton	360	422	500
Scenario	**Parameter**	**Low**	**Expected Value**	**High**
100% Coal	Coal Train Distance, km	322	644	966
	Coal Mine Methane, m^3/tonne	11.2	13.2	15.6
10% Hybrid Poplar	Biomass Truck Distance, km	16.1	80.5	322
	Coal Train Distance, km	322	644	966
	Biomass Yield, kg/hectare-yr.	8,688	15,355	18,829
	Coal Mine Methane, m^3/tonne	11.2	13.2	15.6
	Direct Land Use, kg CO_2e/kg	0.215	0.264	0.466
	Indirect Land Use, kg CO_2e/kg	0.0755	0.0925	0.164
10% Forest Residue	Biomass Truck Distance, km	16	80	322
	Coal Train Distance, km	322	644	966
	Biomass Yield, kg/hectare-yr.	8,688	15,355	18,829
	Coal Mine Methane, m^3/tonne	11.2	13.2	15.6

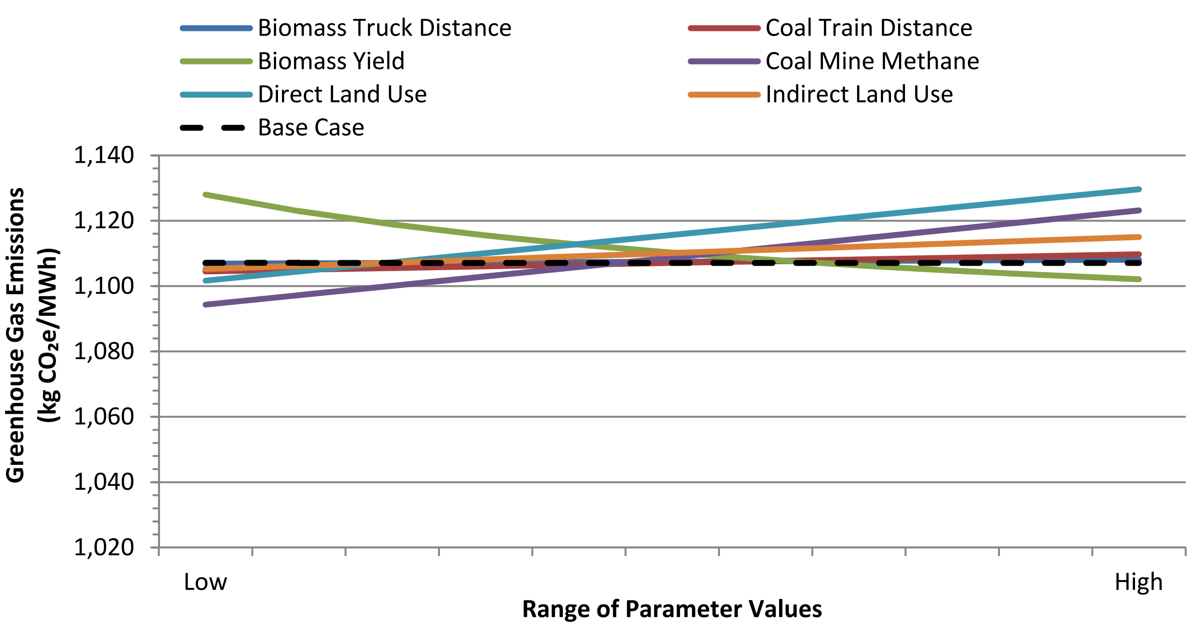
Figure 4-6 shows the response of GHG results to changes in parameter values for the coal-only scenario. In this figure, the dashed line represents the expected value GHG result for the scenario (1,118 kg CO_2e/MWh), and each solid line shows the LC GHG emissions along a range of values for a given parameter (as shown in **Table 4-4**) when all other parameters in the model are held constant. The vertical distance traversed by each line shows the range of uncertainty it contributes to the GHG results. For example, in the coal-only scenario, the coal mine emission factor can introduce an uncertainty of 32 kg CO_2e/MWh while the coal train distance introduces an uncertainty of only 5.7 kg CO_2e/MWh. The slope of each line represents the sensitivity of the corresponding parameter. For example, in the coal-only scenario, the GHG results are more sensitive to the emission factor for coal mine methane than the transport distance for the coal train.

Figure 4-6: GHG Uncertainty and Sensitivity of Key Parameters for Coal-only Case



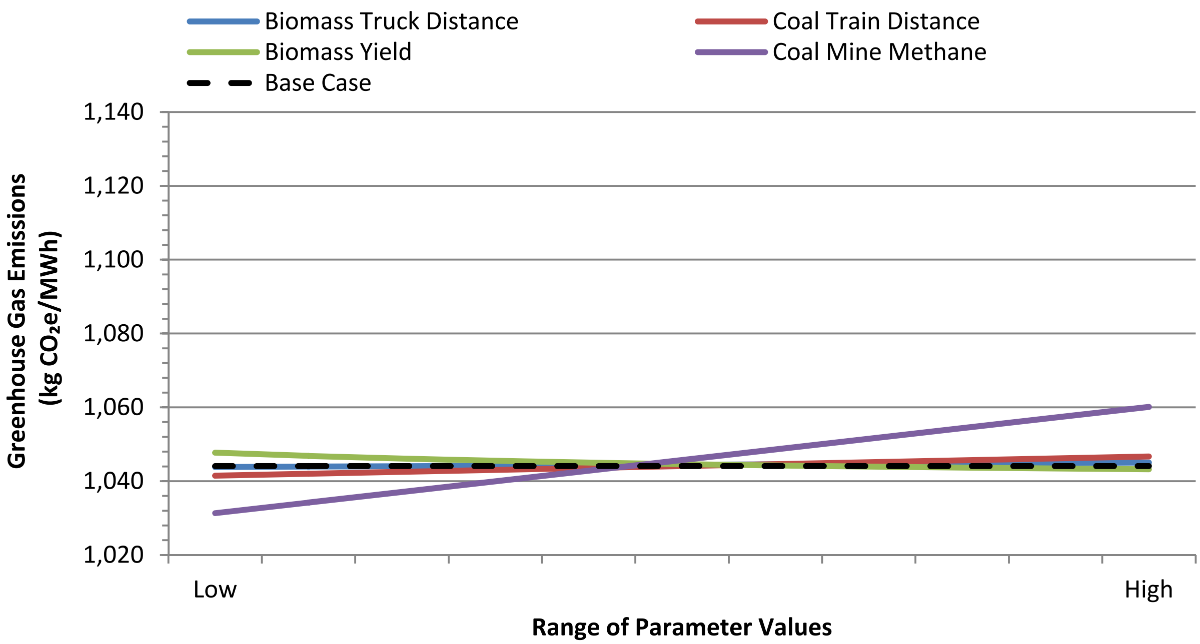
The uncertainty and sensitivity for the HP co-firing scenario is shown in **Figure 4-7**. The co-firing of HP is unique, because, in contrast to the other scenarios of this analysis, it uses a dedicated energy crop that incurs burdens from land use change and includes cultivation and harvesting activities that are affected by biomass yield rate. In addition to the coal mine emission factor from the acquisition of Illinois No. 6, the uncertainty and sensitivity of GHG results for the co-firing of HP are driven by biomass yield rate and direct land use.

Figure 4-7: GHG Uncertainty and Sensitivity of Key Parameters for Co-firing of Hybrid Poplar



The uncertainty and sensitivity for the forest residue co-firing scenario is shown in **Figure 4-8**. The GHG emissions for the acquisition of forest residue are not significantly affected by biomass yield rate and have no GHG emissions from direct or indirect land use change. Similar to the coal-only scenario, most of the GHG uncertainty and sensitivity for the co-firing of forest residue is driven by the emission factor for coal-mine methane.

Figure 4-8: GHG Uncertainty and Sensitivity of Key Parameters for Co-firing of Forest Residue



4.5.2 Other Air Emissions

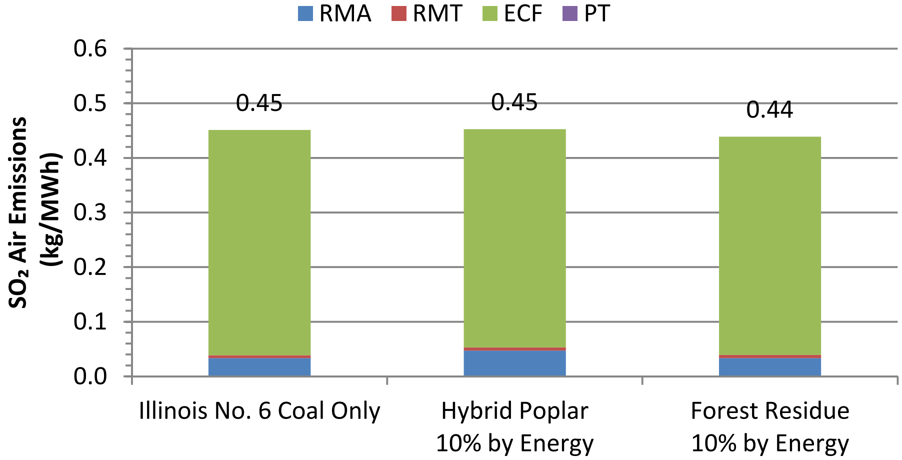
In addition to GHG emissions, this analysis accounts for criteria air pollutants and other air emissions of concern. These emissions are shown per MWh of delivered electricity for the three scenarios of this analysis in **Table 4-5**.

Table 4-5: Other Air Emissions for Coal and Biomass Power Systems

Scenario	Emission	Units	RMA	RMT	ECF	PT	Total
100% Illinois No. 6 Coal	Pb	kg/MWh	1.49E-06	6.47E-08	2.64E-09	0	1.55E-06
	Hg	kg/MWh	2.65E-07	5.11E-09	3.76E-05	0	3.79E-05
	NH_3	kg/MWh	2.54E-05	2.00E-04	0.00E+00	0	2.26E-04
	CO	kg/MWh	1.00E-02	1.68E-02	1.53E+00	0	1.55
	NO_X	kg/MWh	1.68E-02	1.41E-02	1.07E+00	0	1.10
	SO_2	kg/MWh	3.33E-02	5.52E-03	4.12E-01	0	4.51E-01
	VOC	kg/MWh	2.87E-03	2.61E-03	-5.16E-15	0	5.49E-03
	PM	kg/MWh	1.49E-03	1.79E-02	2.60E-01	0	2.79E-01
10% Hybrid Poplar	Pb	kg/MWh	3.05E-06	1.18E-07	1.25E-07	0	3.30E-06
	Hg	kg/MWh	3.62E-07	8.08E-09	3.43E-05	0	3.46E-05
	NH_3	kg/MWh	8.47E-03	1.84E-04	7.29E-06	0	8.67E-03
	CO	kg/MWh	3.53E-02	1.63E-02	1.44E+00	0	1.50
	NO_X	kg/MWh	4.05E-02	1.31E-02	9.28E-01	0	9.81E-01
	SO_2	kg/MWh	4.70E-02	5.88E-03	4.00E-01	0	4.53E-01
	VOC	kg/MWh	5.00E+00	2.79E-03	3.30E-02	0	5.04
	PM	kg/MWh	7.61E-02	1.63E-02	2.41E-01	0	3.33E-01
10% Forest Residue	Pb	kg/MWh	1.57E-06	1.18E-07	1.25E-07	0	1.81E-06
	Hg	kg/MWh	2.54E-07	8.08E-09	3.43E-05	0	3.45E-05
	NH_3	kg/MWh	3.27E-05	1.84E-04	7.29E-06	0	2.24E-04
	CO	kg/MWh	2.51E-02	1.63E-02	1.44E+00	0	1.49E+00
	NO_X	kg/MWh	1.83E-02	1.31E-02	9.28E-01	0	9.59E-01
	SO_2	kg/MWh	3.33E-02	5.88E-03	4.00E-01	0	4.39E-01
	VOC	kg/MWh	4.71E-03	2.79E-03	3.30E-02	0	4.05E-02
	PM	kg/MWh	6.79E-02	1.63E-02	2.41E-01	0	3.25E-01

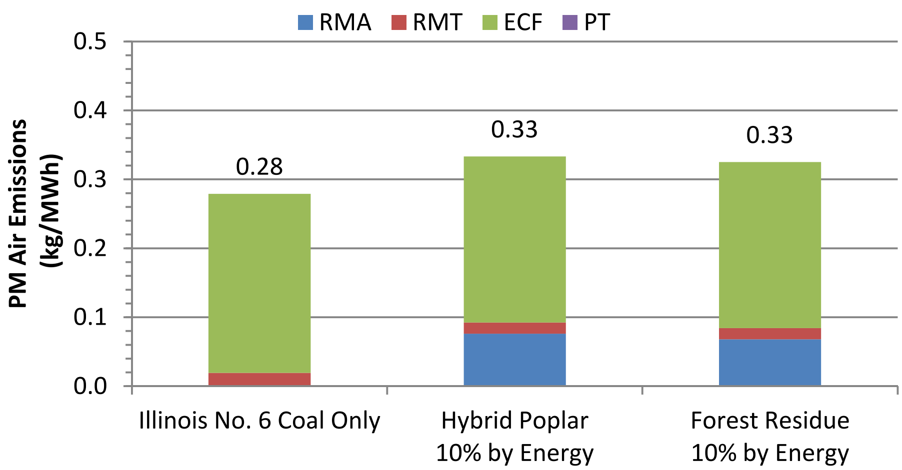
The co-firing of coal and biomass is effective at reducing SO_2 emissions at a power plant, in comparison with standalone coal firing. However, SO_2 emissions are also released at other stages of the LC, including RMA. For instance, the co-firing scenario for HP has lower ECF SO_2 emissions than the coal-only case, but higher RMA SO_2 emissions than the coal-only case, making the total SO_2 emissions of the two cases virtually equal. In fact, the LC SO_2 emissions of the three scenarios of this analysis all fall within a narrow range; the percent difference between the highest and lowest SO_2 emissions is only 3.1 percent. **Figure 4-9** compares the LC SO_2 emissions of the coal and biomass power systems.

Figure 4-9: SO_2 Emissions from Coal and Biomass Power Systems



The grinding and drying of biomass, which is necessary for effective biomass combustion in a PC boiler, produces significant emissions of PM. PM is also produced from land disturbance during the cultivation and harvesting of biomass, as well as from the combustion of diesel in farming and other equipment during the cultivation and harvesting of biomass. **Figure 4-10** compares the LC PM emissions from co-firing and other biomass systems, illustrating that PM emissions are higher for biomass systems than for a PC boiler system that burns only coal.

Figure 4-10: PM Emissions from Coal and Biomass Power Systems



Ammonia (NH_3) and volatile organic compounds (VOC) are two air emissions produced during the cultivation of biomass and are an order of magnitude higher for the HP scenario than for the other scenarios of this analysis. HP is the only feedstock of this analysis that requires fertilizer. NH_3 and VOC emissions are released during the production and use of fertilizer, so the co-firing scenario with HP has significantly higher NH_3 and VOC emissions than the other scenarios. The LC emissions of NH_3 and VOC are shown in **Figure 4-11** and **Figure 4-12**, respectively.

Figure 4-11: Ammonia Emissions from Coal and Biomass Power Systems

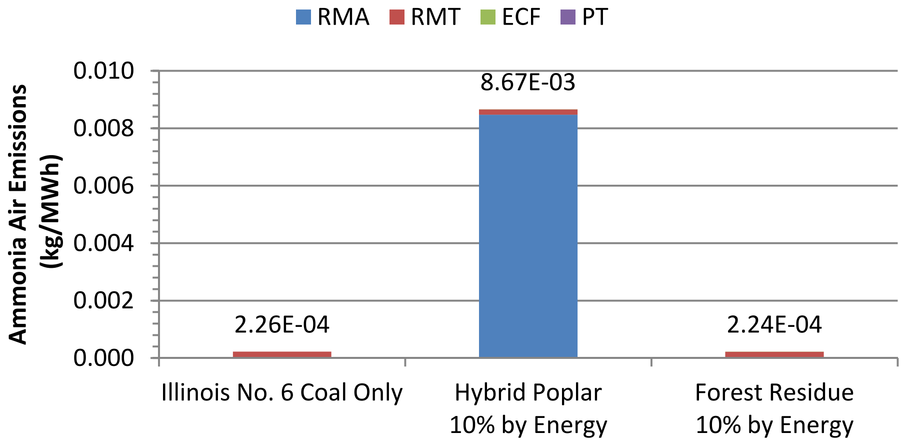


Figure 4-12: VOC Emissions from Coal and Biomass Power Systems

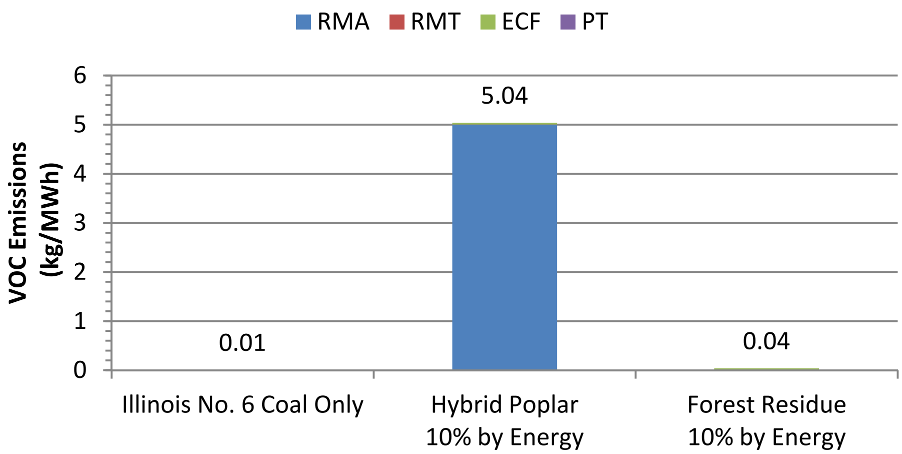


Figure 4-13 and **Figure 4-14** show the percent change in non-GHG emissions when converting a coal-only power system to a co-fired system that consumes 10 percent, by energy, of HP or forest residue. These figures set the coal-only scenario as a baseline, and demonstrate that some emissions increase, and others decrease, when a coal-only system is converted to a co-fired system. For example, the co-firing of HP and forest residue increase LC PM_{10} emissions by 19 percent and 17 percent, respectively, but decrease LC NO_X emissions by 11 percent and 13 percent, respectively.

Figure 4-13: Change in Other Air Emissions when Converting to 10% Co-Firing of Hybrid Poplar

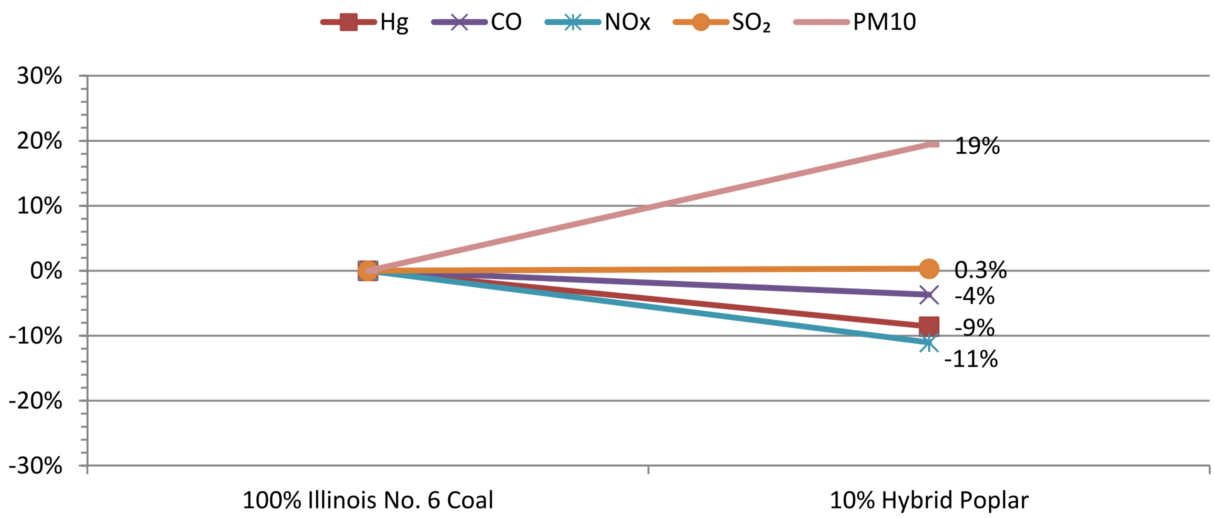
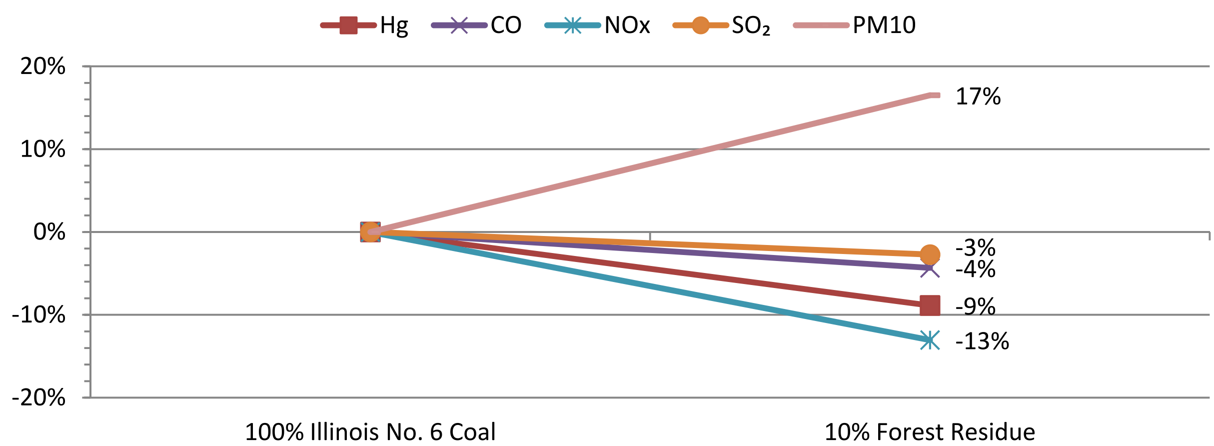


Figure 4-14: Change in Other Air Emissions when Converting to 10% Co-Firing of Forest Residue

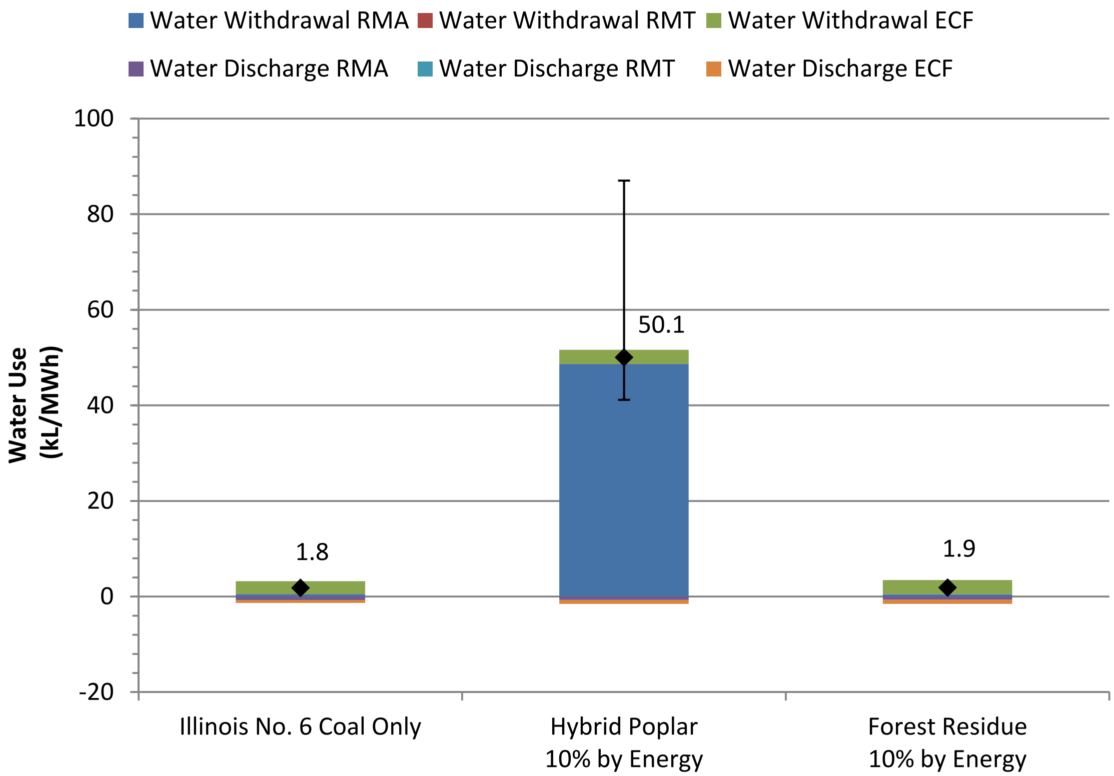


VOC and NH_3 emissions are not shown in **Figure 4-13** and **Figure 4-14**, because, as discussed above, they are significantly higher for the HP scenario and skew the scale of the figures.

4.5.3 Water Use

The LC water use for the coal and biomass power systems is shown in **Figure 4-15**. Water withdrawals are shown as positive values, and water discharges are shown as negative values.

Figure 4-15: Water Use by Coal and Biomass Power Systems



As shown by **Figure 4-15**, the acquisition of HP withdraws more water than other processes of this analysis. Coal extraction consumes relatively low volumes of water. Forest residue is a byproduct of another industry and, from a LCA perspective, does not consume significant volumes of water during RMA.

The cultivation of HP accounts for the majority of water withdrawal during RMA. At an annual yield of 6.8 tons/acre, the cultivation of HP withdraws 431 L of water per kg of harvested biomass. The co-firing of HP (at 10 percent by energy in a 550 MW PC boiler) requires the harvesting 111 kg of biomass for the delivery of 1 MWh of electricity. Factoring these water withdrawal and biomass consumption rates gives a total RMA water withdrawal rate of 47,800 L/MWh, which accounts for 98 percent of RMA water withdrawal shown by the HP scenario in **Figure 4-15** . Cultivation withdraws 80 percent of water from rain, 10 percent from ground water, and 10 percent from surface water.

Uncertainty in water use for the co-firing of HP is driven by the possible yield rates of biomass. The ratio of the highest and lowest biomass yield rates is 2.2; similarly, the ratio of high and low water use for the co-firing of HP biomass case is 2.1.

4.5.4 Energy Return on Investment

The energy return on investment (EROI) is the ratio of energy produced to total energy expended. The functional unit of this LCA is 1 MWh of delivered electricity and represents the amount of energy produced by the system. The total energy expended is the energy content of all resources (crude oil, coals, natural gas, uranium, and renewable resources) that enter the LC boundaries minus the useful energy in the final product (the functional unit).

EROI calculations are often applied to the LC of a primary fuels. If the energy expended on the extraction, transport, and processing of a fuel is 10 percent of the useful energy in the fuel, the EROI can be expressed as a ratio of 10:1. In addition to the extraction and delivery of primary fuels, the boundaries of this analysis include the conversion of primary energy to electrical energy. The power plant has an overall efficiency of 33 percent, which means that 67 percent of the energy entering the power plant is expended. Thus, the EROI for electric power systems is less than one.

The total energy produced and expended by the systems of this analysis is shown in **Table 4-6**. The coal-only scenario (100 percent Illinois No. 6 Coal) has the highest return on energy, with an EROI of 0.43:1. The two co-firing cases (10 percent HP and 10 percent forest residue) have slightly lower returns at 0.40:1 and 0.41:1, respectively.

Table 4-6: EROI Calculation for Coal and Biomass Power Systems

Resource	100% Illinois No. 6 Coal	10% Hybrid Poplar	10% Forest Residue
Useful Energy Produced, MJ[1]	**1.0**	**1.0**	**1.0**
Total System Energy Input, MJ	**3.3**	**3.5**	**3.5**
Crude oil, MJ	< 0.1	< 0.1	< 0.1
Hard coal, MJ	3.3	3.0	3.0
Lignite, MJ	< 0.1	< 0.1	< 0.1
Natural gas, MJ	< 0.1	0.1	< 0.1
Uranium, MJ	< 0.1	< 0.1	< 0.1
Biomass, MJ	0	0.3	0.3
Total Energy Expended, MJ	**2.3**	**2.5**	**2.5**
EROI	**0.43:1**	**0.40:1**	**0.41:1**

Table 4-7 shows the EROI when calculated only around the boundaries of raw material extraction and raw material transport for the three feedstocks of this analysis. These upstream EROIs represent the useful thermal energy in feedstocks as delivered to the power plant divided by the energy expended during feedstock acquisition and transport. Coal has a higher upstream EROI than biomass because it is an energy dense feedstock that can be efficiently extracted and transported. HP has the lowest upstream EROI because its acquisition includes fuels consumed by farming equipment and natural gas used for fertilizer production. Forest residue has a higher upstream EROI than HP because it does not require any cultivation inputs (use of farming equipment or fertilizer).

[1] The useful energy produced is expressed in terms of MJ to be consistent with the resource energy inputs. 3,600 MJ is equal to 1 MWh.

Table 4-7: EROI for Upstream Co-firing Feedstocks

Resource	Total (RMA + RMT)		
	Coal	HP	Forest Residue
Useful Energy Produced, MJ	**1.0**	**1.0**	**1.0**
Total System Energy Input, MJ	**1.02**	**1.21**	**1.07**
Crude oil, MJ	0.01	0.08	0.06
Hard coal, MJ	1.01	0.02	< 0.1
Lignite, MJ	< 0.1	< 0.1	< 0.1
Natural gas, MJ	< 0.1	0.11	0.01
Uranium, MJ	< 0.1	< 0.1	< 0.1
Renewables, MJ	< 0.1	1.00	1.00
Total Energy Expended, MJ	**0.02**	**0.21**	**0.07**
EROI	**44:1**	**4.7:1**	**15:1**

5 Cost Analysis of Coal and Biomass Co-firing

The life cycle costs (LCC) of coal and biomass co-firing were calculated by performing a discounted cash-flow analysis over the lifetimes of the energy conversion facilities. The LCC model accounts for the delivered price of coal and biomass feedstocks, other Operating and Maintenance (O&M) costs, and total capital costs in order to calculate the cost of electricity (COE).

The LCC scenarios mirror the scenarios performed for the environmental portion of this analysis:

- 100 Percent Coal Combustion in a PC Boiler
- Co-firing of Coal and HP in a PC Boiler
- Co-firing of Coal and Forest Residue in a PC Boiler

5.1 Cost Data for Coal and Biomass Power Systems

The capital and O&M costs of this analysis are based on data developed by NETL during a recent study on supercritical boilers designed to co-fire biomass. The original data were representative of a facility with the same capacity (550 MW) as the energy conversion facility of this analysis. It was also representative of a boiler with 39 percent efficiency and was scaled to 33 percent efficiency to be consistent with the boiler performance of this analysis.

All capital costs of the existing PC plant are sunk costs that have already been depreciated, so they are not accounted for in this analysis. However, the capital costs of the retrofit process are included in this analysis. The capital costs for retrofitting a PC facility to co-fire biomass are $230/kW. This value is based on a detailed cost buildup that NETL conducted for a greenfield supercritical co-fired power plant. It was adapted for this analysis by identifying the costs of key biomass handling equipment, adjusting for the different efficiencies of supercritical and subcritical power plants, and increasing capital costs by 10 percent to account for the contingencies of retrofitting. It is assigned an uncertainty range of +/- 30 percent.

Variable O&M costs include non-fuel consumables and increase as plant output increases and are the same for all cases of this analysis. This analysis uses a variable O&M value of $7.65/MWh.

Fixed O&M costs account for labor and other operating costs that do not change as the plant output changes. Due to the additional costs for operating biomass handling equipment, the fixed O&M costs for co-firing are higher than those for the coal-only scenario. The fixed O&M costs for the coal-only case are $86.6/kW-yr.; the fixed O&M costs for the co-firing scenarios are $91.1/kW-yr.

The fuel prices for coal, HP, and forest residue are $1.64/GJ, $4.27/GJ, and $1.73/GJ. These prices are assigned an uncertainty of +/-30 percent. The fuel costs for each scenario are based on the component costs of the feedstock mix. The calculation of fuel costs for each of the three scenarios is described below:

- **100 Percent Coal Combustion:** The cost of bituminous coal is $1.64/GJ. At a 33.0 percent plant efficiency (which is equivalent to a heat rate of 10.909 GJ/MWh) the fuel costs are $17.89/MWh.
- **Co-firing of Coal and Hybrid Poplar:** The cost of bituminous coal is $1.64/GJ (in 2007 dollars). The cost of HP is $4.27/GJ. At a 32.8 percent plant efficiency (which is equivalent to a heat rate of 10.985 GJ/MWh) and a 90/10 energy split between coal and biomass feedstocks, the fuel costs are $20.90/MWh

- **Co-firing of Coal and Forest Residue:** The cost of bituminous coal is $1.64/GJ. The cost of forest residue is $1.73/GJ, with an uncertainty range of +/- 30 percent. At a 32.8 percent plant efficiency (which is equivalent to a heat rate of 10.985 GJ/MWh) and a 90/10 energy split between coal and biomass feedstocks, the fuel costs are $18.11/MWh.

The cost data for the three LCC scenarios are summarized in **Table 5-1**.

Table 5-1: LCC Cost Data for Coal and Biomass Power Scenarios

Parameter	Units	100% Coal Combustion	Co-firing of Coal and Hybrid Poplar	Co-firing of Coal and Forest Residue
Capacity	MW	550	550	550
Capacity Factor	%	85		
Capital	2007$/kW	N/A	230 +/- 30%	
Cost of Coal	2007$/GJ	1.64 +/- 30%		
Cost of Biomass (Dry)	2007$/GJ	N/A	4.27 +/- 30%	1.73 +/- 30%
Heating Value of Coal (HHV)	MJ/kg	27.14		
Heating Value of Biomass (HHV)	MJ/kg	N/A	18.02	
Plant Efficiency	%	33.0	32.8	
Plant Heat Rate	MJ/MWh	10,909	10,985	
Fixed O&M	2007$/kW-yr.	86.6	91.1	
Variable O&M (Excluding Fuel)	2007$/MWh	7.65	7.65	

5.1.1 Financial Assumptions

In addition to cost data, it is necessary to specify the financial assumptions of the LCC model. The coal and biomass systems are low-risk financial ventures that are a part of investor-owned utilities. Capital is financed using a 50 percent debt and 50 percent equity ratio. The debt term for new capital is 15 years and is depreciated using an accelerated method (a modified accelerated cost recovery [MACRS]). The construction period for new equipment is 1 year. The internal rate of return 12 percent. The financial parameters for this analysis are summarized in **Table 5-2**.

Table 5-2: Financial Parameters for LCC of Coal and Biomass Co-firing

Scenario	Financial Assumption
Financial Structure Type	Low Risk Investor-owned Utility
Debt Fraction (1 - Equity)	50.0%
Interest Rate	4.50%
Debt Term	15
Plant Lifetime	30
Depreciation Period (MACRS)	20
Tax Rate	38.0%
O&M Escalation Rate	3.0%
Capital Cost Escalation During the Capital Expenditure Period	3.6%
Base Year	2007
Required Internal Rate of Return on Equity (IRROE)	12.0%
Construction Period for New Equipment	1 year

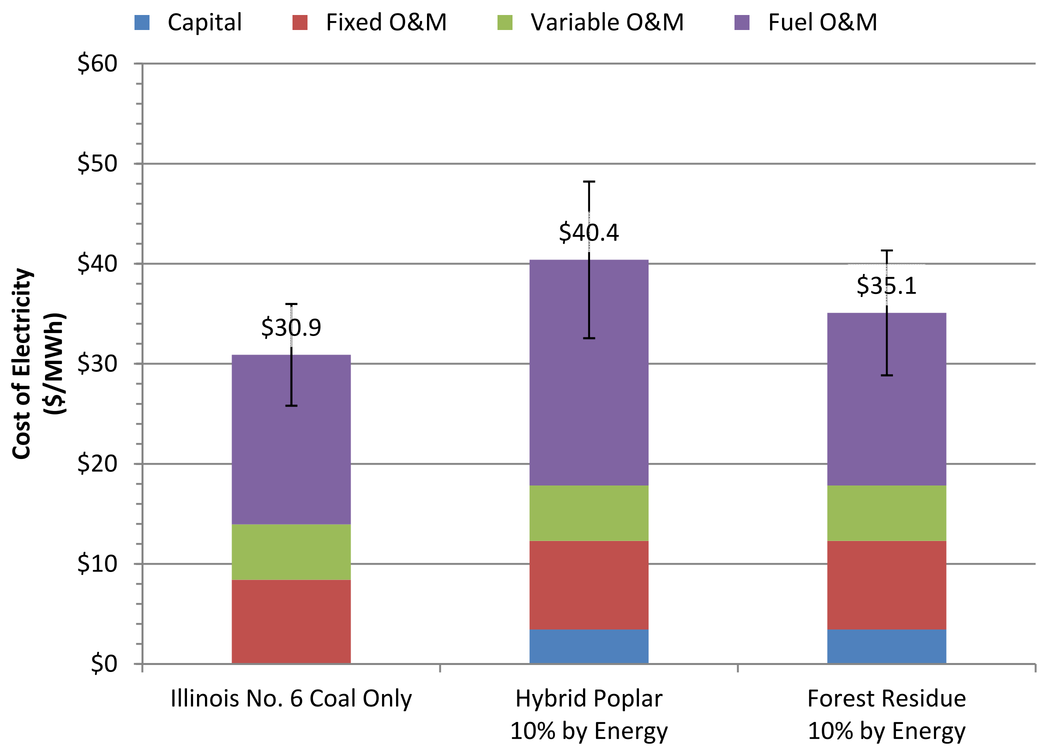
5.2 LCC Results

The COE of the three scenarios ranges from $30.9 to $40.4 per MWh (in 2007 dollars). These results are shown in **Table 5-3** and **Figure 5-1**.

Table 5-3: COE Results for Coal and Biomass Power Systems

Cost Category	100% Coal Combustion	Co-firing of Coal and Hybrid Poplar	Co-firing of Coal and Forest Residue
Capital	$0.00	$3.45	$3.45
Fixed O&M	$8.42	$8.85	$8.85
Variable O&M	$5.53	$5.53	$5.53
Fuel O&M	$16.95	$22.56	$17.26
Total	**$30.90**	**$40.40**	**$35.10**

Figure 5-1: COE Results for Coal and Biomass Power Systems

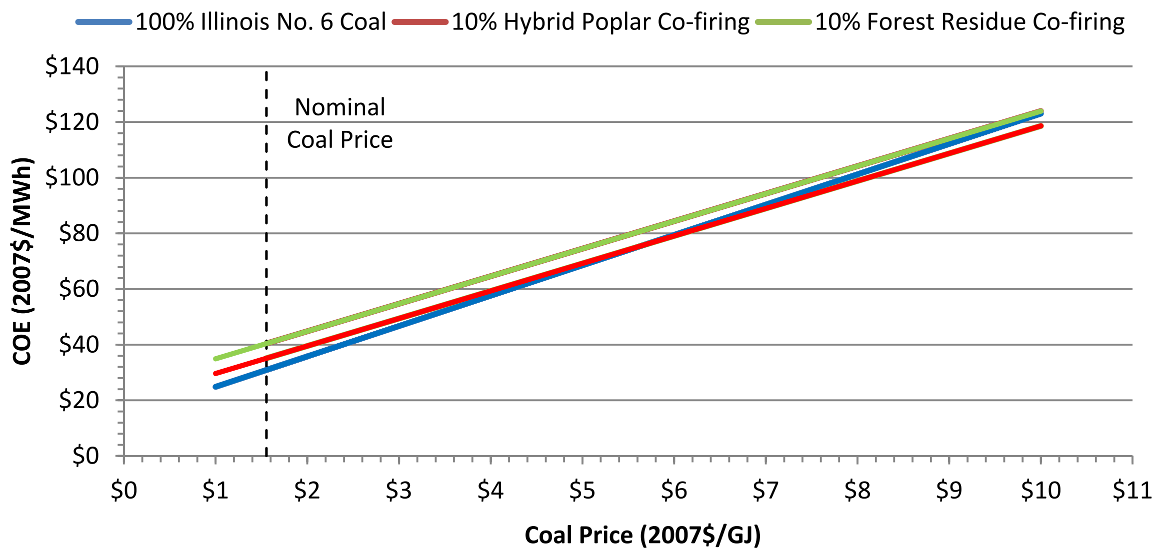


The retrofit of an existing PC plant to co-fire HP increases the COE from $30.9//MWh to $40.4/MWh (a 31 percent increase). Similarly, the COE for co-firing forest residue is $35.1/MWh (a 14 percent increase from the coal-only scenario). These increases are due to the capital costs for biomass handling equipment and boiler modifications, as well as the relatively high costs of the biomass feedstocks.

The error bars shown in **Figure 5-1** represent the uncertainties in capital and feedstock costs, as shown above in **Table 5-1**. The fuel and capital costs have uncertainty ranges that are +/- 30 percent of their expected values. The coal-only scenario does not have any capital expenditures, and capital costs account for between 8 and 9 percent of the COE for the co-firing scenarios. Most of the uncertainty shown in **Figure 5-1** is caused by uncertainty in feedstock costs.

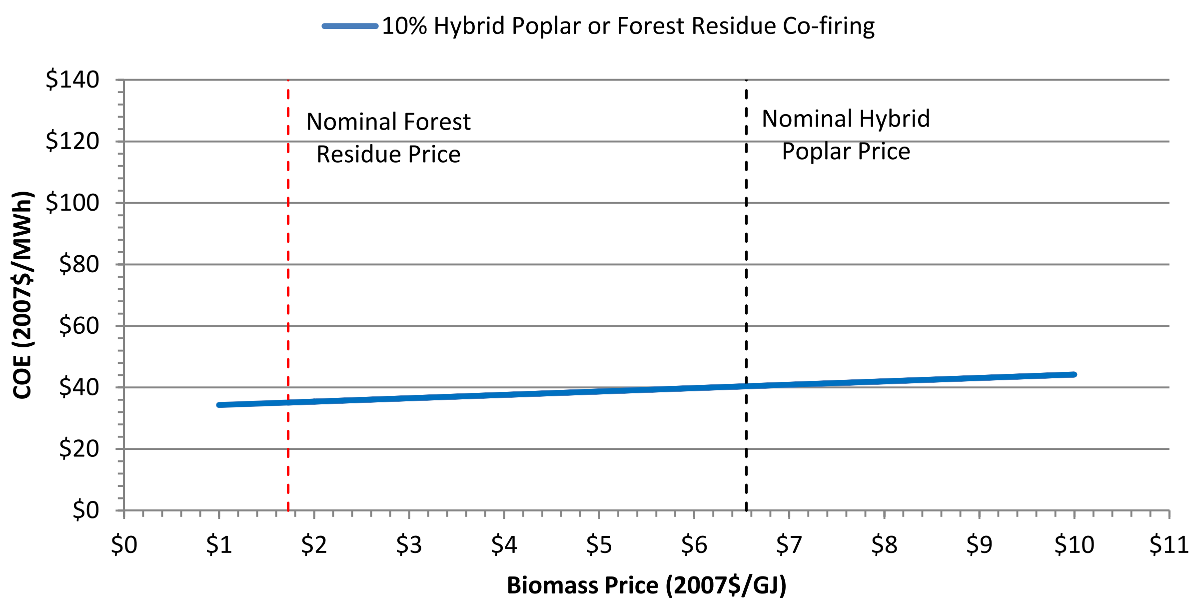
The sensitivity of the COE results to changes in coal prices is shown in **Figure 5-2**, which includes a line for each of the three scenarios and shows how the COE changes when the price of coal is increased from $1/GJ to $10/GJ and all other parameters are held constant. The slopes of the lines indicate the degree of sensitivity – steep slopes correspond to highly sensitive parameters, while flat slopes correspond to parameters with low sensitivities. The slopes of the three scenarios are similar because coal composes at least 90 percent of feedstock input (on an energy basis) for all scenarios. Note that the coal-only case (100 percent Illinois No. 6 coal) has the steepest slope; it consumes coal exclusively, so it is more sensitive to changes in coal prices than the co-firing scenarios. The vertical dashed line in **Figure 5-2** shows the expected price for Illinois No. 6 coal ($1.55/GJ) and intersects the other lines at their expected COEs.

Figure 5-2: Sensitivity of COE to Coal Price



The sensitivity of COE results to changes in biomass prices is shown in **Figure 5-3**. This graph is based on a constant coal price and a range of biomass prices. In this cost analysis, the only difference between HP and forest residue is their delivered costs, so only one line is necessary for illustrating COE sensitivity to biomass prices. In comparison to changes in coal prices illustrated in **Figure 5-2**, COE is not as sensitive to changes in biomass prices because the co-firing scenarios consume only 10 percent biomass (by energy). The vertical, dashed lines in **Figure 5-3** show the expected prices for the two biomass types and intersect the other line at the expected COE of each co-firing case.

Figure 5-3: Sensitivity of COE to Biomass Price



6 Barriers to Implementation

The barriers to implementing co-fired systems include adverse changes to the operating characteristics of boiler systems as well as unexpected changes in the biomass supply chain.

The moisture content of biomass feedstock can lower the efficiency of a boiler, alter the residence time of fuel in a boiler, and, in turn, result in incomplete biomass combustion, although the latter is usually not as much of an issue (Ortiz, et al., 2011). The introduction of biomass to a system that was originally designed to burn coal can also result in a significant increase in slagging, fouling, and ash deposition depending on the type and percentage of biomass that is co-fired. However, power plants that have co-fired biomass have been able to adjust conditions to minimize the technical issues that co-firing biomass presents, and operator experience has shown minimal technical challenges when co-firing with 10 percent or less (by energy) with forest residues (Ortiz, et al., 2011).

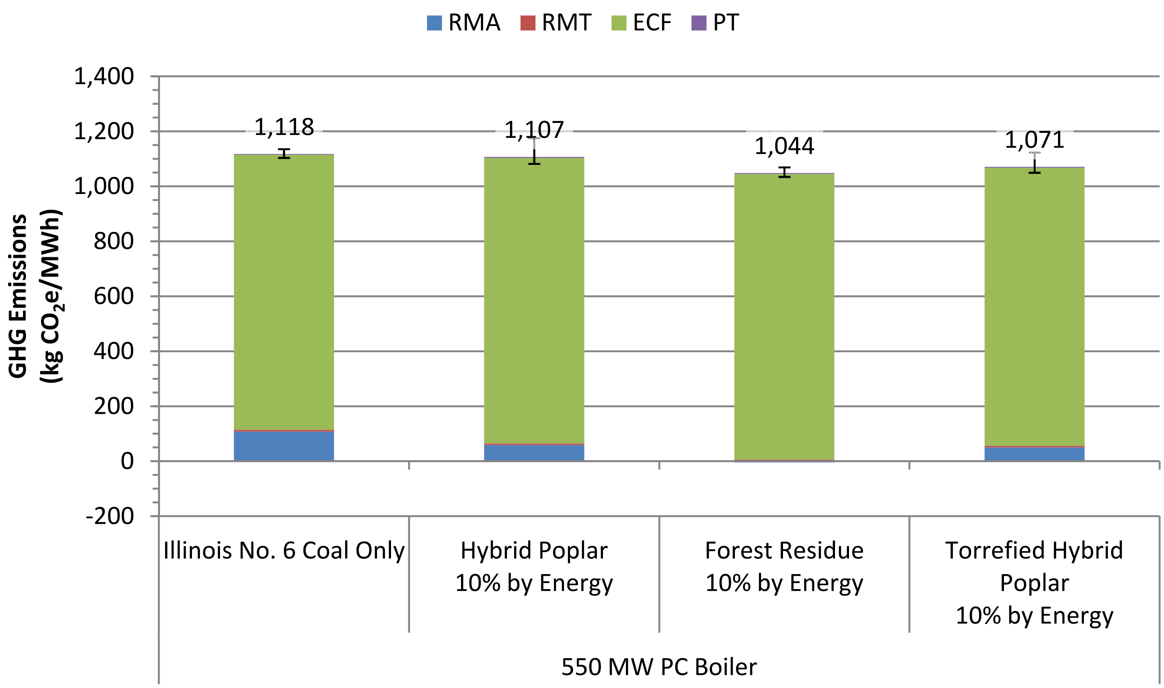
Another barrier to implementing co-fired power is the deterioration of the gypsum that is co-produced at co-fired power plants. Co-product gypsum is sold to wallboard producers. Wallboard producers have a very strict specification for the crystalline structure of lignin in their product. Coal plants will not co-fire biomass if there is a chance that the gypsum specifications will be altered to the point where it is no longer attractive as a co-product.

The uncertainties in the biomass supply chain are due in part to competing markets for biomass feedstocks. For example, between 2006 and 2009, two biomass power plants in California suspended production in response to poor economic conditions in the lumber industry and low contract prices for energy (O'Neill, Nuffer, Gonclaves, Bartholomy, & Jones, 2010). The struggling lumber industry resulted in a reduction in the supply of woody residues to the power plants, and low contract prices for energy reduced the revenues of the power plants.

Biomass from forest thinning is a potential feedstock source for co-firing, but disagreement about proper forest management practices introduces uncertainty to the supply of biomass from forest thinning. Forest thinning has been touted as a potential requirement in order to prevent rampant forest fires, and also as a carbon management solution to increase the carbon sequestration rate of forests. The Healthy Forest Restoration Act of 2003 supports forest thinning as a strategy for preventing forest fires and expedites the environmental review process required for forest thinning projects (USDA, 2004). However, research is conflicting in terms of costs and benefits of forest thinning. Some forestry experts argue that forest dynamics vary significantly from region to region, as do the environmental impacts or benefits of thinnings. If thinning is done improperly, it can leave behind biomass that is more flammable than an unthinned forest. Further, thinning must be conducted frequently (every two years) to be effective at preventing forest fires (Robbins, 2006). Extreme weather conditions and other related natural forces can also cause supply disruptions or change the quality of biomass feedstocks. Land ownership issues can also complicate the procurement of biomass feedstocks.

Torrefaction is a technology that can reduce the supply chain uncertainty of biomass. Torrefaction can be performed at large collection depots that not only increase carbon density but, when combined with pelleting, can give biomass a carbon density similar to coal. Torrefied biomass can also be stored longer than untreated biomass. The improved physical characteristics of torrefied biomass make long-distance transport more economical, which increases the radius of collection for biomass and, in turn, reduces supply chain uncertainty. However, while torrefaction improves the supply characteristics of biomass, it does not significantly improve the GHG profile of co-fired systems. This analysis developed a unit process for torrefaction and incorporated it within the supply chain for HP. The LC GHG emissions from the co-firing of torrefied poplar at a 10 percent share of feedstock energy are 1,071 kg CO_2e/MWh. This result is 4.2 percent lower than the coal-only scenario and 3.3 percent lower than the HP (untorrefied) co-firing scenario, but 2.6 percent higher than the co-firing of forest residue. As shown by **Figure 6-1**, torrefaction reduces the GHG emissions for the first two LC stages (RMA and RMT), but does not significantly reduce the GHG emissions from the ECF.

Figure 6-1: GHG Emissions from the Co-firing of Torrefied Biomass in Comparison to Other Study Scenarios



7 Risks of Implementation

Policy uncertainty and regulatory hurdles are key risks of implementing co-fired power systems.

The implementation of a Renewable Portfolio Standard (RPS) is one way to encourage the growth of renewable energy. One mechanism of an RPS is a market for renewable energy credits (REC). RECs are purchased on the open market and provide a subsidy to producers of renewable energy. Without regulation targeting GHG emissions, the future of co-firing is dependent on the facilities being able to receive RECs for the practice because of the operating and capital costs of biomass relative to coal. Many states have RPSs, but only California and a region of New England have markets for RECs (Ortiz, et al., 2011). Unfortunately, these two areas of the country do not have a significant resource base of biomass, and the current market price of RECs in New England is too low to encourage utilities to switch to biomass (Ortiz, et al., 2011).

State level directives and plans, such as California's Bioenergy Action Plan, help to move government toward regionalized support for increased biomass collection and utilization. Additional statewide and national requirements and incentives are still developing. However, since sourcing of biomass is a major concern for many energy facilities that rely on biomass (Ortiz, et al., 2011), additional regulatory developments that further support biomass collection and use would help to support growth of biomass co-firing. In many cases, it is challenging for a corporation to build a portfolio of renewable energy sources that meets all regulatory provisions. For example, the California Energy Commission notes that California's RPS does not allow electricity that is imported from an out-of-state generator to count toward California's renewable targets unless the out-of-state facility is new or repowered (O'Neill, et al., 2010).

Entirely new co-firing projects, where a new biomass facility is installed side-by-side with a new coal-power facility, would be subject to a full suite of national- and state-level environmental regulations and permitting requirements including, as relevant, the National Environmental Policy Act, the Clean Air Act, the Endangered Species Act, and various other environmental protection regulations. Retrofit projects, where biomass co-firing is added to an existing plant, may require comparatively reduced environmental compliance and permitting, although this is expected to vary based on state regulations, funding sources, and project design. The conversion of existing power plants to co-fired facilities is seen as the most cost effective method for biomass combustion. The California Energy Commission compared the capital costs of retrofitting existing facilities to combust biomass to the capital costs of new biomass facilities. Converting a facility so it can co-fire coal and biomass has capital costs of $400-700/kW; the costs of new biomass power plants are much higher, ranging from $2,600 - $3,000/kW (O'Neill, et al., 2010).

8 Expert Opinions

The feasibility of co-fired power is further illuminated by the opinions of plant operators and other stakeholders.

The RAND Corporation interviewed managers of co-fired power plants. These interviews provide insight into key issues behind the implementation of co-fired systems, including fuel selection, combustion characteristics, and co-product deterioration (Ortiz, et al., 2011). The managers of coal-fired power plants are reluctant to co-fire any type of biomass (woody or herbaceous), because their power plants were designed to burn coal exclusively. The long-term effects of biomass co-firing on installed process equipment are still not known since most testing has been on a relatively short time-scale. In those tests, the impacts of mixing coal and biomass were minimal. The lower energy density and higher moisture content of biomass (as compared to coal) can reduce the net energy output of a power plant. Most plant managers are aware of this possible drop in efficiency, but most plant managers do not consider it a major concern (Ortiz, et al., 2011).

If the operators of a coal-fired power plant decide to switch to biomass co-firing, woody biomass is more preferable than herbaceous biomass. The higher ash content of herbaceous biomass results in higher combustion residues than other fuel types. These residues can lead to poor boiler performance and increased maintenance requirements. No data are available for large-scale, long-term co-firing characteristics of coal and herbaceous biomass, and thus the reluctance to use herbaceous biomass may be influenced more by perception than by actual practice. (Ortiz, et al., 2011).

In most co-firing cases, plant managers must use locally sourced biomass, which means they have no flexibility in the type of biomass to use for co-firing. A key cost driver for biomass is the transportation distance from the site of acquisition to the power plant. According to NRG Energy, the transportation of woody biomass farther than 100 miles is cost prohibitive. Longer distances may be feasible if barge or rail can be used, but these modes of transport do not align with the locations of biomass resources and power plants. A power plant operator can control biomass feedstock costs by establishing contracts with suppliers. However, the biomass supply chain consists of many small suppliers. According to NRG Energy, many biomass delivery contracts are meaningless because small suppliers do not have the resources to pay the penalties associated with breaking contracts. Further, for woody biomass, if the cost of wood for non-energy applications increases significantly, some suppliers may be willing to break their contracts with power plants in order to enter other markets. (Ortiz, et al., 2011)

In addition to plant operators, there are other stakeholders who are not convinced that the co-firing of coal and biomass is an environmentally-preferable practice. The following criticisms are pulled from recent literature and do not necessarily reflect the viewpoints of the cited authors:

- Co-firing coal and biomass incentivizes large power plants to stay open and prolongs their dependence on coal (McElroy, 2008).
- Co-firing biomass with coal prevents the use of biomass combustion residues for fertilizer (McElroy, 2008).
- Opponents of Duke Energy’s 370 MW co-fired trials in South Carolina claim that the forest residues used by the project do not fall within state requirements for renewable fuels (Downey, 2010).

The above criticisms appear to be based more on perception than on in-depth analysis; however, the resolution of perception-based issues is important to the success of implementing a technology.

9 Summary

This analysis provides insight into the role of co-fired power as a future energy source in the U.S. The criteria used for evaluating the role of co-fired power are as follows:

- Resource Base
- Growth
- Environmental Profile
- Cost Profile
- Barriers to Implementation
- Risks of Implementation
- Expert Opinions

The **resource base** of biomass is in close proximity to existing coal-fired power plants. However, utilities should consider other aspects of the biomass supply chain and energy conversion technologies before investing in co-fired power plants. Further, torrefaction is a viable technology for reducing biomass supply uncertainty and increasing the collection radius of a biomass resource, but does not translate to significant reductions in GHG emissions.

The **environmental profile** is based on an LCA that accounts for a full list of metrics, including air emissions and resource consumption. The conversion of an existing 550 MW net PC boiler to a system which co-fires HP at a 10 percent share of feedstock energy reduces LC GHG emissions by only one percent (1,118 kg CO_2e/MWh vs. 1,107 kg CO_2e/MWh). Most of the GHG reductions due to the displacement of coal are offset by the land use, fertilizer use, and efficiency losses of co-firing. The co-firing of forest residue is more effective at reducing GHG emissions than HP; when forest residue is co-fired at a 10 percent share of feedstock energy, the LC GHG emissions are reduced by 6.6 percent. The key advantage of forest residue, in comparison to HP, is its low GHG emissions for material acquisition. The results for other air emissions show that co-firing increases the LC lead (Pb), VOC, and PM emissions. Co-firing reduces LC SO_2 emissions if forest residue is used, but not if HP is used. Co-firing does lead to reductions in LC emissions of CO, NO_X, and Hg.

The **costs** of co-firing were evaluated using an LC costing approach. The retrofit of an existing PC plant to co-fire HP at a 10 percent share of feedstock energy increases the COE from \$30.9/MWh to \$40.4/MWh (a 31 percent increase). If forest residue is co-fired instead of HP, the increase in COE is only 14 percent. The capital costs of the co-fired systems account for a small share (approximately 8 percent) of the COE because this analysis assigns capital costs only to new equipment, not existing equipment. The key drivers of cost uncertainty are the feedstock prices for coal and biomass.

The technical **barriers** to the implementation of co-firing systems include biomass supply uncertainty, higher-than-expected decreases in boiler efficiencies, equipment fouling, and co-product degradation. The **risks** of implementing co-fired systems include regulatory uncertainties; the future of co-firing is dependent on the facilities being able to receive renewable energy credits for the practice because of the operating and capital costs of biomass relative to coal. These risks and barriers and risks are echoed by **expert opinions** that are summarized in a recent report by the RAND Corporation. According to RAND’s research, the long-term effects of biomass co-firing on installed process equipment are not known. (Ortiz, et al., 2011)

Co-firing is seen as a way of reducing the GHG emissions of existing coal-fired power plants. However, the incorporation of biomass into an existing coal-fired system increases the complexity of feedstock acquisition. Further, the acquisition of biomass has unique GHG burdens that offset, in part, the GHG reductions from the displacement of coal with biomass. Due to the higher feedstock prices of biomass, the co-firing of biomass at a 10 percent share of feedstock energy can increase the COE by as much as 31 percent – a disproportionately large increase in comparison to the corresponding GHG reductions. Technical concerns include decreases in boiler efficiency and degradation of coal combustion byproducts that are typically used in the production of construction materials. Other risks include regulatory uncertainty; without policies that encourage the use of renewable feedstocks, there is no incentive for producers to invest in co-fired systems.

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Appendix A: Constants and Unit Conversion Factors

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Table A-1: Common Unit Conversions

Category	Input			Output	
	Value	Unit		Value	Unit
Mass	1	lb.	=	0.454	kg
	1	Short Ton	=	0.907	Tonne
Distance	1	Mile	=	1.609	km
	1	Foot	=	0.305	m
Area	1	$ft.^2$	=	0.093	m^2
	1	Acre	=	43,560	$ft.^2$
Volume	1	Gallon	=	3.785	L
	1	$ft.^3$	=	28.320	L
	1	$ft.^3$	=	7.482	Gallons
Energy	1	Btu	=	1,055.056	J
	1	MJ	=	947.817	Btu
	1	kWh	=	3,412.142	Btu
	1	MWh	=	3,600	MJ

Table A-2: IPCC Global Warming Potential Factors (Forester et al., 2007)

IPCC GWP Factor	Vintage	20 Year	100 Year	500 Year
CO_2	2007	1	1	1
CH_4	2007	72	25	7.6
N_2O	2007	289	298	153
SF_6	2007	16,300	22,800	32,600
CO_2	2001	1	1	1
CH_4	2001	62	23	7
N_2O	2001	275	296	156
SF_6	2001	15,100	22,200	32,400

Appendix B: Data for Coal and Biomass Acquisition and Transport

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B.1 Land Preparation for Hybrid Poplar

The scope of land preparation for hybrid poplar includes farming activities used for land area preparation for short rotation woody crop (SRWC) biomass. As modeled, land preparation operations consider diesel consumption, where diesel is used as fuel to operate farm equipment (a tractor used to pull a disk tiller). The air emissions from diesel combustion and fugitive dust from the use of land preparation equipment are also considered, where fugitive dust is categorized as particulate matter (PM) emissions to air. Water use and emissions to water are assumed to comprise a negligible contribution to the direct operations of land preparation, and therefore are not characterized here.

Land preparation operations include farming activities to prepare land area for seeding of biomass. Land preparation is assumed to occur once during (at the very beginning of) the study period. The key adjustable parameter modeled here is the annual yield of SRWC. The annual yield of SRWC (kg/acre-year) is used to translate the values for diesel consumption, diesel emissions, and fugitive dust emissions from a basis of quantity per acre to a basis of quantity per kg of SRWC biomass production.

Diesel is consumed by the tractor as it pulls the disk tiller. A tractor consumes an average of 10.26 gallons of diesel per hour (John Deere, 2009b). The diesel consumption of equipment used in farming cultivation activities was calculated based on specifications of a 1,953 rpm tractor consuming 10.26 gal/hour of diesel fuel and a disk tiller of 4.78 m (188 inches) width (John Deere, 2009a, 2009b). Assuming that the tractor operates at 5.8 miles per hour (mph), an average operating speed, and by multiplying the width of the disk tiller by the operating speed of the tractor, the land coverage rate is estimated at 11 acres per hour. Multiplying this land coverage rate by the fuel consumption rate, the estimated diesel consumption is 0.93 gal/acre-pass. This calculation assumes that the tractor makes two passes over the site and the total diesel consumption is 1.86 gal/acre calculated.

The combustion of diesel results in the direct emission of greenhouse gases (GHG) and criteria air pollutants (CAP). The emissions factors for GHGs are based on DOE instructions for the voluntary reporting of GHGs (DOE, 2007). Emissions factors for PM (particulate matter), NO_X (nitrogen oxides), and VOCs (volatile organic compounds) are based on EPA documentation on air emissions from non-road diesel engines. These emissions factors are expressed in terms of the mass of emissions per bhp-hr (brake horsepower-hour), which requires a determination of the bhp-hr of the tractor. This unit process uses a conversion factor of 0.066 gal/bhp-hr (SCAQMD, 2005) to apply the emissions factors for PM, NO_X, and VOC to a basis of gallons of diesel combusted in non-road heavy equipment.

Emissions of SO_2 (sulfur dioxide) are calculated stoichiometrically by assuming that diesel has a sulfur content of 15 ppm (DieselNet, 2009b) and that all sulfur in diesel is converted to SO_2 upon combustion. The calculated emissions factor for diesel is 2.53E-05 kg SO_2/L.

The emissions factors for CO (carbon monoxide) are based on Tier 4 emission standards, which specify an array of CO emissions factors across a range of engine sizes (DieselNet, 2009b). This analysis assumes that the engine of the tractor is greater than 175 horsepower, and the calculated emissions factor for diesel is 0.010 kg CO/L.

Fugitive dust emissions are generated by the disturbance of surface soil during land preparation. Fugitive dust emissions from land preparation are estimated using an emissions factor specified by WRAP (Western Regional Air Program) (Countess Environmental, 2004) , which conducted air sampling studies on ripping and sub-soiling practices used for breaking up soil compaction. The emissions factor for fugitive dust is 1.2 lb PM/acre-pass. The total emissions of fugitive dust are 6.53 kg PM/acre (0.0025 kg/kg biomass).

The yield rate of SRWC is discussed previously, in the main body of text for this document. Please refer to prior discussion of biomass yield values and sensitivity. Properties of SRWC relevant to this unit process are indicated in **Table B-1**. Heating values for SRWC are provided as a reference point to document assumptions and for comparison with other biomass types.

Table B-1: Properties of Land Preparation Activities

Property	Value	Units	Reference
SRWC Default Yield	13,700	kg/acre-year	Study Value
HHV SRWC	7938	Btu/lb.	NETL 2009
LHV SRWC	8438	Btu/lb.	NETL 2009

B.2 Hybrid Poplar Cultivation

The scope of cultivation for hybrid poplar includes farming activities used for cultivation for SRWC biomass. As modeled, cultivation operations consider the mass of diesel needed to power farming equipment, the mass of fertilizer and herbicides required for cultivation, and associated emissions. Also considered are emissions from the combustion of diesel used in cultivation equipment, particulate matter emissions associated with fugitive dust, water input flows required for biomass cultivation, runoff water, emissions of criteria air pollutants, and carbon dioxide uptake by cultivated biomass.

Cultivation operations include the seeding of biomass and activities including the application of water, fertilizer, and herbicides as warranted for the cultivation of SRWC biomass. SRWC is planted once every 5 years and harvested at the end of the fifth year. For planting, three passes are made across the field: 2 passes for tilling and 1 pass for planting. The SRWC is fertilized each year using N, P, and K fertilizers (see additional discussion below), and is sprayed with an herbicide each year. Water is supplied to the SRWC via a combination of rainfall and irrigation water, with the irrigation water being a 50%-50% mix of surface water and groundwater. Energy required for the application of fertilizers, herbicides, and application of water is assumed to be negligible.

Diesel is consumed by the tractor as it pulls the disc tiller and the planter equipment. A tractor consumes diesel an average of 10.26 gallons per hour (John Deere, 2009b). The diesel consumption of equipment used in farming cultivation activities was calculated based on specifications of a 1,953 rpm tractor.

The width of a disk tiller is 4.77 m (15.7 ft) (John Deere, 2009a). The tractor with a tiller implement has an average operating speed of 5.8 miles per hour (mph) (Tillage Answers, 2009). By multiplying the width of the disk tiller by the speed of the tractor, a land coverage rate of 11 acres per hour is calculated. The tractor makes two passes over the site, requiring 1.86 gal/acre of diesel.

The width of a planter is 2.39 m (7.83 ft) (C&G 2004). The tractor with a planter has an average operating speed of 4 miles per hour (mph) (Tillage Answers, 2009). By multiplying the width of the planter and speed of the tractor, a land coverage rate of 3.8 acres per hour is estimated. The tractor planter makes a single pass of the land site. The ratio of the fuel consumption rate and land coverage rate is a diesel consumption rate of 2.7 gal/acre.

Diesel emissions factors, per gallon of diesel consumed, are based on non-road diesel engine data (DOE, 2007; Federal Register, 2004; SCAQMD, 2005). The combustion of diesel results in the direct emission of GHGs and CAPs. The emissions factors for GHGs are based on DOE instructions for the voluntary reporting of GHGs (DOE, 2007). Emissions factors for PM (particulate matter), NO_X (nitrogen oxides), and VOCs (volatile organic compounds) are based on EPA documentation on air emissions from non-road diesel engines. These emissions factors are expressed in terms of the mass of emissions per bhp-hr (brake horsepower-hour), which requires a determination of the bhp-hr of the tractor. This unit process uses a conversion factor of 0.066 gal/bhp-hr (SCAQMD, 2005) to apply the emissions factors for PM, NO_X, and VOC to a basis of gallons of diesel combusted in non-road heavy equipment.

Emissions of SO_2 (sulphur dioxide) are calculated stoichiometrically by assuming that diesel has a sulphur content of 15 ppm (DieselNet, 2009a, 2009b) and that all sulphur in diesel is converted to SO_2 upon combustion. The calculated emissions factor for diesel is 2.53E-05 kg SO_2/L.

The emissions factors for CO (carbon monoxide) are based on Tier 4 emission standards, which specify an array of CO emissions factors across a range of engine sizes (DieselNet, 2009a). This unit process assumes that the engine of the tractor is greater than 175 horsepower and calculated emissions factor for diesel is 0.0104 kg CO/L.

Fugitive dust emissions are generated by the disturbance of surface soil during tilling . Planting and other activities involving farm equipment (such as applying fertilizers and herbicides) are assumed to generate insignificant levels of fugitive dust compared to tilling. Fugitive dust emissions from tilling are estimated using an emissions factor specified by WRAP (Western Regional Air Program) (Countess Environmental, 2004), which conducted air sampling studies on ripping and sub-soiling practices used for breaking up soil compaction. The emissions factor for fugitive dust is 1.2 lb PM/acre-pass. The tractor makes two passes of the site during tilling and thus has a fugitive dust emissions factor of 2.4 lbs PM/acre. Replanting is assumed to take place every 5 years and horizon time of the study is assumed to be 30 years. Multiplying the replanting time and dividing by the horizon time, the total emissions of fugitive dust are 0.2177 kg PM/acre calculated.

Fertilizer use quantifies the amounts of nitrogen, phosphorous, and potassium required, while herbicide use is quantified in support of weed control. The mass of fertilizer was calculated (RAND, 2009), but upstream emissions for fertilizer production and delivery are not included in the boundary of this unit process. Ten percent (by weight) of the nitrogen that is applied as fertilizer is assumed to be volatilized. Of that volatized nitrogen fertilizer, it is further assumed that 1 percent reacts to form N_2O. Of the 90 percent of nitrogen fertilizer that does not volatize, soil processes release 0.0125 tons of N_2O per ton of nitrogen.

Biomass production for this study is assumed to occur in the Midwestern United States (U.S.), a region where rain during the growing season contributes substantially to the water requirements of crops (DOC, 2009). However, in many cases, supplemental irrigation water is also used to support increased yield and to relieve crop water stress during dry periods. As a result, quantifying water use and consumption for biomass crops grown in the Midwest is relatively complicated as compared to, for instance, biomass crops grown in the West, where growing season irrigation is the only significant source of water (Southeast Farm Press, 2007). Based on Midwest rainfall average data, 17,300 m3/acre is estimated. Water is applied as rainfall or as irrigation water from a combination of surface water and groundwater sources. Runoff water occurs as a result of excess rainfall, and agricultural pollutants, including nitrogen and phosphorous emissions, associated with stormwater runoff are quantified (USDA, 2009). Total irrigation water is estimated to be 135 mm/year (Brown et al., 2000) based on the difference between the total evapo-transpiration demand for the crop and the amount of rainfall. Total runoff water is assumed to be 17 mm/year based on data from Brown et al. (2000) and is calculated to be 70,314 liters per acre per year.

Loss of nitrogen and phosphorous via runoff water is also accounted for within the unit process. Waterborne nitrogen and phosphorous emissions are based on a study completed by Mallarino et al (2009), which provides survey data for agricultural runoff water, in order to quantify nutrient loss from fields. Anticipated nutrient loading rates were calculated by averaging data provided for a conventional nutrient management scheme.

Carbon dioxide (CO_2) uptake is quantified based on available carbon content data for SRWC. CO_2 uptake is calculated stoichiometrically from the amount of carbon contained in SRWC, assuming that all carbon was originally taken up as CO_2. The average carbon fraction of SRWC is assumed to be 49.63 percent (Stolarski, 2008).

Key modeled adjustable parameters include the annualized biomass yield rate, and the mass of N, P and K fertilizers used on site per acre. The yield rate of SRWC is discussed previously, in the main body of text for this document. Please refer to prior discussion of biomass yield values and sensitivity. NETL currently recommends default values of 70.3 kg-N/acre, 9.5 kg-P/acre and 47.2 kg-K/acre for nitrogen, phosphorous and potassium, respectively. Properties of SRWC biomass cultivation operation activities are illustrated in **Table B-2**. Heating values for SRWC are provided as a reference point to document assumptions and for comparison with other biomass types applied outside of this unit process, as relevant.

Table B-2: Properties of Biomass Cultivation Activities

Property	Value	Units
SRWC yield default	13,700	Study Value
LHV SRWC	7938	MJ/kg
HHV SRWC	8438	MJ/kg

B.3 Hybrid Poplar Harvesting

The scope of hybrid poplar harvesting covers the harvesting and storage operations for SRWC biomass. As modeled, harvesting operations considers diesel consumption and biomass production, including associated emissions. Diesel is used as fuel for crop harvesting equipment – specifically, a combined tree harvester/chipper. The air emissions from diesel combustion and fugitive dust from harvesting equipment are also considered. Fugitive dust is categorized as particulate matter (PM) emissions to air. Water use and emissions to water are not characterized in here, because they are assumed to comprise a negligible contribution to the direct operations of harvesting trees.

Harvesting operations considered include the harvesting of SRWC through the production of SRWC biomass that is ready for transport to the energy conversion facility. The harvesting operations for SRWC biomass production are based on the estimated diesel consumption of harvesting operations equipment, the direct emissions from diesel combustion, fugitive dust emissions caused by surface dust that is disturbed by harvesting equipment, and the annual yield rate of SRWC.

Diesel is consumed by the tree harvester to harvest and chip trees. The diesel consumption by harvesting equipment was calculated based on specifications of a 440 hp diesel engine consuming 0.15 kg diesel/hp-hour (0.35 lb/hp-hour) (John Deere, 2008). Assuming that harvesting operations produce approximately 3 tons SRWC/hour (Gaffney & Yu, 2003), header operating speed is 2,721 kg/hour. By multiplying the replanting time by the annual yield rate of the biomass, and dividing by the header operating speed, the coverage area by harvester is 0.2142 acres/hour. By dividing biomass production per hour by a harvesting coverage area, the fuel per coverage area is 386.62 L/acre-pass. By dividing the annual yield rate of the biomass, the estimated diesel consumption is 0.03044 L/kg biomass.

The combustion of diesel results in the direct emission of GHGs and criteria air pollutants (CAPs). The emissions factors for GHGs are based on DOE instructions for the voluntary reporting of GHGs (DOE, 2007). Emissions factors for PM, nitrogen oxides (NO_X), and volatile organic compounds (VOCs) are based on EPA documentation on air emissions from non-road diesel engines. These emissions factors are expressed in terms of the mass of emissions per bhp-hr (brake horsepower-hour), which requires a determination of the bhp-hr of the harvester/chipper. This unit process uses a conversion factor of 0.066 gal/bhp-hr (SCAQMD, 2005) to apply the emissions factors for PM, NO_X, and VOC to a basis of gallons of diesel combusted in non-road heavy equipment.

Emissions of sulphur dioxide (SO2) are calculated stoichiometrically by assuming that diesel has a sulphur content of 15 ppm (DieselNet, 2009a) and that all sulphur in diesel is converted to SO_2 upon combustion. The calculated emissions factor for diesel is 2.53E-05 kg SO_2/L.

The emissions factors for CO (carbon monoxide) are based on Tier 4 emission standards, which specify an array of CO emissions factors across a range of engine sizes (DieselNet, 2009b). The diesel engine of the harvester is greater than 175 horsepower, and the calculated emissions factor for diesel is 0.0104 kg CO/L.

Fugitive dust emissions are generated by the disturbance of surface soil when harvesting. Fugitive dust emissions from harvesting activities are estimated using an emissions factor specified by Western Regional Air Program (WRAP) (Countess Environmental, 2004), which conducted air sampling studies on ripping and sub-soiling practices used for breaking up soil compaction. The emissions factor for fugitive dust is 40.8 lb PM/acre-pass (Gaffney & Yu, 2003). The total emissions of fugitive dust are 0.00146 kg/kg biomass.

The yield rate of SRWC is based on independent studies on willow and poplar hybrids in the Central Upper Peninsula of Michigan by Michigan State University (Miller & Bender, 2008). The average yield is calculated based on data collected by Michigan State University, which is representative of 4 sites. The average for SRWC yield is 2.8 tons/acre, which is used for this study.

The yield rate of SRWC is discussed previously, in the main body of text for this document. Please refer to prior discussion of biomass yield values and sensitivity. Properties of SRWC relevant to this unit process are indicated in **Table B-3**. Heating values for SRWC are provided as a reference point to document assumptions and for comparison with other biomass types.

Table B-3: Properties of SRWC Harvesting

Physical Component/Property	Value	Units	Reference
SRWC Default Yield	13,700	kg/acre-year	Study Value
LHV SRWC	7,938	MJ/kg	NETL 2009
HHV SRWC	8,438	MJ/kg	NETL 2009

B.4 Forest Residue Collection

In contrast to hybrid poplar, the acquisition of forest residue does not require land preparation or cultivation. The acquisition of forest residue involves the use of heavy equipment to collect the byproduct biomass from forestry operations. Data for forest residue collection are based on harvesting data for hybrid poplar, which include activity factors for the operation of heavy equipment per acre of harvested biomass. The energy consumed by heavy equipment depends on the yield rate of forest residue (the amount of residue collected for a given area of forest). At the time of this study, no data are available on the yield rate of forest residue; while forest residue may be more scattered than hybrid poplar, the study assumption is that the trees in a forest are larger than hybrid poplar crops and will yield more biomass per tree. This analysis uses a yield rate of 13,700 kg of forest residue per acre-yr (the same yield rate used for hybrid poplar). It is necessary to have years as a component of the yield rate in order to apportion the useful life of heavy equipment to a unit of harvested forest residue. The properties of forest residue and hybrid poplar are similar, so the heating value of forest residue is modeled with the same heating values as hybrid poplar. The yield rate and heating values for forest residue are shown in **Table B-4**.

Table B-4: Properties of Forest Residue

Physical Component/Property	Value	Units	Reference
Forest Residue Default Yield	13,700	kg/acre-year	Study Value
LHV SRWC	7,938	MJ/kg	NETL 2009
HHV SRWC	8,438	MJ/kg	NETL 2009

B.5 Illinois No. 6 Coal Mining and Preparation

Modeling for the coal mine is based on the Galatia Mine, an underground, bituminous Illinois No. 6 coal mine, having an average production rate of approximately 6.6 million short tons per year. The Galatia Mine is operated by the American Coal Company and is located in Saline County, IL. Sources reviewed in assessing coal mine operations include Galatia mine facilities and equipment, production rates, electricity usage, particulate air emissions, methane emissions, wastewater discharge permit monitoring reports, and communications with Galatia mine staff. When data from the Galatia mine were not available, surrogate data were taken from other underground mines, as relevant.

Coal is extracted from the underground Illinois No. 6 coal seam with wet-head longwall and continuous miners using a longwall mining process. Coal is then loaded onto a conveyor for transport to the surface. At the surface, the coal continues along a conveyor to the crushing facility, where the coal is crushed to approximately 3 inch sizing. Coal then continues to the cleaning facility, where the mineral fraction (approximately 45% of total coal mass) of the run-of-the mine coal is removed via a water-based cleaning and sorting process. The coal is then temporarily stored, until it is eventually loaded onto a railcar for rail transport. Stormwater, which generates on-site runoff from coal stockpiles and other facilities, is treated at a wastewater treatment plant, which discharges to a river. The wastewater treatment plant does not treat mining or coal cleaning process water. These systems are closed-loop in terms of water use, and generate no wastewater discharge.

Coalbed methane emissions from the coal mine, and from the extracted coal during processing and storage, were estimated based on EPA estimates of methane release for coal mines, for a best estimate emission rate of 422 standard cubic feet per short ton. A 40% methane capture rate was used based on data for existing and potential recovery rates (USEPA, 2008a).

Electricity use was estimated based on previous estimates made by EPA for electricity use for underground mining and coal cleaning at the Galatia Mine (USEPA, 2005). Diesel use was estimated for the Galatia mine from 2002 U.S. Census data for bituminous coal underground mining operations and associated cleaning operations (U.S. Census Bureau, 2004).

Emissions of criteria pollutants were based on emissions associated with the use of diesel. EPA Tier 4 diesel standards for non-road diesel engines were used, since these standards would go into effect within a couple years of commissioning of the mine for this study (USEPA, 2004). Diesel is assumed to be ULSD (15 ppm sulfur). Emissions of particulate matter included those due to the combustion of diesel, as well as fugitive coal dust from the mining process. Total coal dust emissions from the Galatia Mine were used based on data for the mine (USEPA, 2005), and were normalized to the reference flow.

Water use was estimated by Galatia Mine staff. Water emissions data, including flows and concentrations of relevant inorganic constituents and biological oxygen demand, were taken from available National Pollutant Discharge Elimination System permit reporting documentation for Galatia Mine from 2005-2008 (USEPA, 2008b).

Properties of Illinois No. 6 coal relevant to underground extraction of Illinois No. 6 bituminous coal provided in **Table B-5**.

Table B-5: Properties of Illinois No. 6 Coal (NETL 2007)

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (Weight %) (Note A)		
	As Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	**100.00**	**100.00**
Sulfur	2.51	2.82
HHV, kJ/kg	27,113	30,506
HHV, Btu/lb.	11,666	13,126
LHV, kJ/kg	26,151	29,544
LHV, Btu/lb.	11,252	12,712
Ultimate Analysis (Weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen (Note B)	6.88	7.75
Total	**100.00**	**100.00**

Notes: (A) the proximate analysis assumes sulfur as volatile matter; (B) by difference.

B.6 Truck Transport of Biomass

Biomass transport is presumed to be via semi truck (tractor-trailer). The modeled truck transport process is designed to be independent of the type of biomass being transported and the location of transport within the U.S., and is considered to be applicable to SRWC biomass for this study. Truck transport operations assume that the biomass is previously loaded into the trailer. Transport operations then considers the transport of biomass from the source area to the energy conversion facility.

Based on the function which the tractor trailer will perform, it is assumed that the engine used for biomass transport is equivalent to that of a Class 8B truck. The truck (tractor) and trailer combination is classified to have >60,000 lbs of gross vehicle weight. The truck is assumed to be loaded to capacity on the initial haul to the energy conversion facility and to return empty to the farm after unloading. The truck is assumed to be powered by 100 percent conventional diesel fuel from crude oil. **Table B-6** provides the biomass parameters which should be used in the calculations based on which is being transported. **Table B-7** provides emission factors for operation of the tractor trailer.

Table B-6. Biomass Parameters for Tractor Trailer Transport

Parameter	Units	Short Rotation Woody Crops
Fuel Efficiency, Empty	miles/gallon	9.4
Fuel Efficiency, Loaded	miles/gallon	5.1
Capacity	kg	24071

Table B-7. Emission Factors for Tractor Trailer Transport

Emission	Value	Units (Per kg Cargo Transported)	Reference
Carbon Dioxide	4.4310E-06	kg	(ANL, 2011)
Methane	2.0465E-08	kg	(ANL, 2011)
Nitrous Oxide	2.6297E-08	kg	(ANL, 2011)
Sulfur Dioxide	7.2172E-09	kg	(ANL, 2011)
Nitrogen Oxides	7.5106E-08	kg	(ANL, 2011)
Particulate Matter, unspecified	3.7553E-09	kg	(ANL, 2011)
VOCs, unspecified	4.4255E-07	kg	(ANL, 2011)
Carbon Monoxide	2.3489E-06	kg	(ANL, 2011)

B.7 Train Transport of Coal

Data for the train transport of coal is compiled from several sources, to create an emissions profile for criteria air pollutants and other pollutants of interest. The modeled process assumes that the prepared coal is loaded into the train prior to the initiation of train transport operations. Loaded coal is then transported from the coal mine to the energy conversion facility.

Adjustable parameters considered in the model help to determine the amount of diesel needed for transportation. These include the energy content of the diesel, the power demand of the train, and the roundtrip transport distance. The default values for diesel energy content and train power demand are, respectively, 36,641 Btu/liter and 225 Btu/kg-km. Sulfur content of the diesel fuel is also included as an adjustable parameter, with a default value of 0.000015 kg S/kg diesel. The sulfur content of the fuel is important due to the effect on the resulting air emissions. Finally, the quantity for the flow of the cargo has been added to enable calculation of fugitive dust losses.

All emission factors for diesel combustion are provided in **Table B-8**. It is assumed that the train will be operating around or after the year 2015, and will therefore be in compliance with the US Environmental Protection Agency's (EPA) Tier 4 emissions standards, which will become effective in 2015. The Tier 4 standards include regulations for NO_X, PM, VOCs, and CO (US Federal Register, 2008). Emission factors for CO_2, CH_4, and N_2O were taken from the documentation for the US Energy Information Administration's (EIA) form for the voluntary reporting of GHGs (DOE, 2007). Stiochiometric conversions determined the SO_2 emissions from diesel combustion. It was assumed that all sulfur contained in the diesel fuel would be converted to SO_2.

The fugitive dust emissions were based on an Australian coal mine transport study (Connell Hatch, 2008). The amount of mercury released as a result of the combustion of diesel was based on data from a study examining gasoline and diesel fuel combustion in the San Francisco Bay area of California (Conaway, Mason, Steding, & Flegal, 2005). An emission factor for ammonia from diesel combustion from mobile sources was obtained from a report that developed emission factors for various sources of ammonia (Battye, Battye, Overcash, & Fudge, 1994). Any calculations needed to convert or adjust the data to be applicable in NETL studies are supplied in the associated DS mentioned above.

Table B-8. Emission Factors for Train Transport

Emission	Value	Units (Per kg Cargo Transported)	Reference
Carbon Dioxide	1.3716E-02	kg	(DOE, 2007)
Methane	4.9052E-04	kg	(DOE, 2007)
Nitrous Oxide	1.5942E-04	kg	(DOE, 2007)
Sulphur Oxide	2.8682E-07	kg	NETL Engineering Calculation
Nitrogen Oxides	7.9709E-04	kg	(U.S. Federal Register, 2008)
Particulate Matter, Unspecified	1.8517E-05	kg	(Connell Hatch, 2008; US Federal Register, 2008)
VOCs, Unspecified	8.5841E-05	kg	(U.S. Federal Register, 2008)
Carbon Monoxide	9.1972E-04	kg	(U.S. Federal Register, 2008)
Mercury (+II)	8.0844E-20	kg	(Conaway, et al., 2005)
Ammonia	6.7446E-08	kg	(Battye, et al., 1994)

B.8 Biomass Drying

Biomass drying is required for the reduction of moisture content in incoming biomass to the energy conversion facility, in support of coal-biomass co-firing. Biomass drying is the process of removing excess water from moist biomass, as delivered to the energy conversion facility, in order to make it suitable for combustion and power production. This unit process considers energy use (natural gas) as well as emissions of carbon dioxide (CO_2), methane, nitrous oxide (N_2O), criteria pollutants, and other key air quality pollutants for which data were available. Dried biomass produced within this unit process is routed into additional processing and/or energy conversion facilities downstream. The reference flow is 1 kg of dried biomass.

Biomass drying is necessary to remove water from hybrid poplar (HP) biomass, which is presumed to have a moisture content of 25 percent (varying from 5 percent to 50 percent) as it arrives from biomass production and transport. Natural gas is presumed to be the sole source of heat energy used for biomass drying. Energy use within the scope of the unit process is therefore limited to the consumption of natural gas as it is burned for heating. Other energy requirements, such as electricity or diesel fuel required for loading and biomass handling, or process requirements, such as conveyors and other electrically powered processes, are assumed to be negligible and were not quantified.

Air quality emissions resulting from combustion of the natural gas, in order to provide heat energy to the process, were quantified using emission factors from the Environmental Protection Agency's (EPA) AP-42 air emission factors for natural gas combustion (USEPA, 1998). Thus, it was presumed that air emissions from natural gas combustion were equivalent to emissions from a natural gas boiler or other sources of direct natural gas combustion. AP-42 data for natural gas combustion emissions were over ten years old, which is viewed as a data limitation. Additional, newer natural gas combustion emissions data should be included as they become available/is identified. Air emissions were quantified for the following constituents: NO_X, carbon monoxide (CO), CO_2, nitrous oxide (N_2O), total particulate matter (PM), sulfur dioxide (SO_2), methane, non-methane volatile organic compounds (VOC), lead (Pb), and mercury (Hg). The drying process for HP biomass also releases non-methane VOCs directly as the biomass is heated and water is driven off. Volatile emissions are quantified based on Banerjee et al. (Banerjee et al., 2006), and account for 2.19E-04 kg non methane volatile organic compound (NMVOC) per kg of dried biomass, which is nearly double the NMVOC emissions associated with natural gas combustion.

Table B-9 shows the energy and material requirements for the drying of biomass. All flows are scaled to the basis of the reference flow (1 kg of dried biomass).

Table B-9: Inputs and Outputs for Biomass Drying

Flow Name	Value	Units (Per Reference Flow)
Inputs		
Natural Gas (Intermediate Product)	1.0005	kg
Outputs		
Dried Biomass (Intermediate Product)	1.00E+00	kg
Nitrogen Oxides (Inorganic Emissions to Air)	1.05E-04	kg
Carbon Monoxide (Organic Emissions to Sir)	6.30E-05	kg
Carbon Dioxide (Organic Emissions to Air)	9.00E-02	kg
Nitrous Oxide (Laughing Gas) (Inorganic Emissions to Air)	4.80E-07	kg
Dust (PM10) (Particles to Air)	5.70E-06	kg
Sulfur Dioxide (Inorganic Emissions to Air)	4.50E-07	kg
Methane (Organic Emissions to Air)	1.73E-06	kg
NMVOC (Unspecified) (Group NMVOC to Air)	2.23E-04	kg
Lead (Inorganic Emissions to Air)	3.75E-10	kg
Mercury (Inorganic Emissions to Air)	1.95E-10	kg

B.9 Biomass Grinding for Coal-Biomass Co-firing

Biomass grinding is required prior to the introduction of biomass into a co-fired boiler. Biomass grinding is the process of size reduction for chipped biomass, as it is received from biomass production and transport, in order to make it suitable for combustion and power production within a pulverized coal (PC) boiler. Because biomass is chipped during the harvesting process (within an upstream unit process), no additional size reduction is required for biomass firing within a stoker boiler. Therefore, this unit process is applicable only to co-firing within a PC boiler. This study considers energy use (electricity) as well as particulate emissions (wood dust) associated with biomass grinding. The reference flow is 1kg of ground biomass.

Biomass arrives at the energy conversion facility under LC Stage #3 (ECF) as chipped HP crop biomass, chipped forestry residuals, or as standard harvest switchgrass, corn stover, and other herbaceous biomass feedstocks. Biomass grinding is assumed to occur within tub grinders designed for grinding woody biomass. Energy requirements for grinding were derived from Ciolkosz and Wallace (2011), which reports that grinding requires 270 to 450 kJ electricity/kilogram biomass. An average value of 360 kJ/kg was used in support of this process. Particulate emissions (PM_{10}) from the grinding process (that is, dust from grinding) were also quantified. Based on Bay Area Air Quality Management District (BAAQMD, 2008), airborne PM_{10} emissions from the grinding of wood in tub grinders results in 0.0144 pound PM_{10} per ton of ground biomass.

Table B-10 shows the energy and emissions for the grinding of biomass in support of coal-biomass co-firing. All flows are scaled to the basis of the reference flow (the conversion of 1 kg of ground biomass).

Table B-10: Inputs and Outputs for Biomass Grinding

Flow Name	Value	Units (Per Reference Flow)
Inputs		
Biomass (Intermediate Product)	1.000012011	kg
Power (Electric Power)	0.36	MJ/kg
Outputs		
Ground Biomass (Intermediate Product)	1.00E+00	kg
Dust (PM10) (Particles to Air)	7.21E-06	kg

B.10 Biomass Torrefaction

The analysis of biomass torrefaction assumes that torrefaction of SRWC biomass takes place in a directly heated moving bed reactor at temperatures between 200 and 300°C, in the absence of oxygen. The ensuing thermal degradation of SRWC biomass removes most of the moisture content and eliminates its fibrous structure. The hemicellulose component of the wood is thermally essentially destroyed by the torrefaction process. This improves both the grindability and calorific value of the torrefied biomass product while also making it resistant to water absorption. The product material is therefore easier to grind, pelletize, package, and transport. These properties make the torrefied biomass product suitable for use as a standalone or blend material with coal in combustion and gasification applications.

The time and temperature requirements for torrefaction can be varied depending on the desired characteristics of the torrefied biomass. The relationship between torrefaction time and temperature may be qualitatively described as follows:

1. As the torrefaction time and temperature increases, the yield of torrefied biomass decreases while the yield of gaseous products such as volatiles and water vapor increases.
2. As the torrefaction time and temperature increases, the calorific value of the torrefied biomass increases.
3. As torrefaction time and temperature increases, the production of CO, CH_4, and C_2 hydrocarbons in the gaseous products increase while the production of CO_2 decreases.
4. At any torrefaction time and temperature, water vapor is always a significant gaseous product – on the order of 50 to 60 percent by mass of the gas stream - even when the biomass is dried to zero or near-zero moisture content. Typically, about 5 to 10 percent of the energy contained in the raw biomass is driven off as part of the gaseous products.

Comprehensive operating data from a commercial existing torrefaction process are not available but Integro Earth Fuels, Inc. has provided ultimate and proximate analyses and calorific values for raw and torrefied Southern pine solids from their test facility in Ashville, North Carolina (Childs, 2012). These data were used as the basis for the mass and energy balances used in developing the torrefaction simulation model.

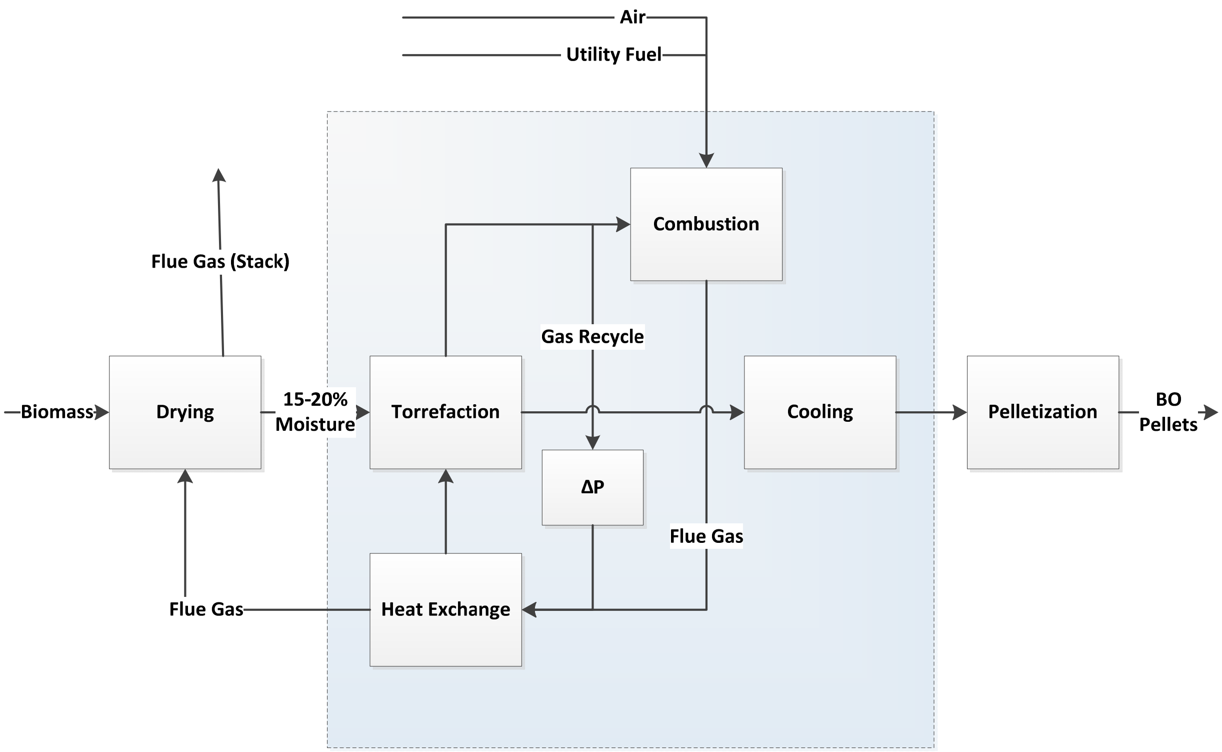
Figure B-1 shows the schematic of the directly heated torrefaction system assumed for this study. This system is under development by ECN of the Netherlands (Bergman, Boersma, Zwart, & Kiel, 2005). In this system some or most of the necessary heat for drying and torrefaction comes from the combustion of the volatile gases emitted during torrefaction. Additional heat when required to balance the heat load can be supplied by using natural gas, other biomass, or other available utility fuels. Air, fuel, and torrefaction gases are combusted in the combustion section of the plant and the flue gas from combustion is passed through a heat exchanger that heats the torrefaction gas recycle stream. The flue gas exiting the heat exchanger is used to dry the biomass before it enters the torrefaction reactor. The cooled flue gas is then discharged through the stack. The heated recycle gas that includes torrefaction gas and combustion flue gas directly contacts the biomass in the torrefaction reactor to supply the heat required for further dehydration and torrefaction. This also acts as the essentially oxygen-free blanket gas. The gases leave the torrefaction reactor and some of the gas is recycled to the torrefaction reactor via the heat exchanger and the rest is sent to the combustor. The solid torrefied biomass product leaves the reactor and is cooled.

In the ECN process the torrefied product is pelletized to produce their BO_2 pellets. In this study, the unpelletized torrefied material is transported from the torrefaction facility to the CBTL Facility where it is ground, mixed with coal and gasified to produce synthesis gas.

Within this study, conceptually the Southern pine is dried to about 10 percent moisture prior to being fed to the torrefaction step. Torrefaction is accomplished in the directly heated moving bed torrefaction chamber at a temperature of 536 ^{o}F (280^{o}C). Heat for torrefaction is provided from a portion of the torrefaction product gas that is recycled and re-pressurized via a forced draft fan or blower, and heat exchanged with flue gas. A combustion chamber with air and natural gas as supplemental fuel burns the combustible portion of the torrefaction gas stream.

Although the torrefaction product gas consists of a wide variety of combustible components, the main constituents are the non-combustibles water and carbon dioxide. The heat content of torrefied solids and gases are dependent on a combination of the type of raw materials and torrefaction operating conditions (temperature and residence time). The heating value of the torrefaction volatiles can be too low to provide the necessary heat for drying and torrefaction in which case supplemental fuel is necessary. Some torrefaction producers like Integro Earth Fuels claim that the process can run autothermally and therefore does not need any supplemental fuel.

Figure B-1: ECN Torrefaction Scenario



Source: (Kiel, 2011a).

Integro Earth Fuels, Inc. has an existing system for torrefaction of SRWC biomass that combines the drying and torrefaction steps into a single unit and requires supplemental fuel only during system start-up. At steady-state, their torrefaction process operates auto-thermally (Childs, 2012). In a torrefaction systems study, Bergman and Boersma of ECN estimate the heat content of the torrefaction product gas to be 5.2 and 14.7 percent the value of the dry feed to the torrefaction reactor for woodcuttings and demolition wood, respectively (Bergman, Boersma, Zwart, et al., 2005). In that study, a portion of the raw wood is burned to provide process heat for the drying and torrefaction steps. For the purposes of this current analysis it is assumed that the default value for the heating content of the volatiles is set at 5.2 percent of the heating value of the feed to estimate the amount of supplemental fuel required.

Kiel reports a torrefaction product gas composition from willow at 260^{o}C for 32 minutes. These include mass yields for a torrefaction gas that contains CO, CO_2, H_2O, acetic acid, furfural, methanol, formic acid and the remainder CH_4, C_xH_y, toluene and benzene (Kiel, 2011b). Bergman and Kiel and

Bergman, *et al* provide mass yields for torrefaction reaction products for willow at 280^{o}C for 17.5 minutes (Bergman, Boersma, Kiel, Prins, & Ptasinski, 2005; Bergman & Kiel, 2005). These data are in the form of mass distributions for solids, lipids (terpenes, phenols, fatty acids, waxes, and tannins), organics (sugars, polysugars, acids, alcohols, furans, and ketones), gases (H_2, CO, CO_2, CH_4, C_xH_y, and benzenes), and water. Emissions of CO_2 and SO_2 are based on the oxidation of combustible constituents in the torrefaction product gas and the natural gas burned as supplemental fuel.

Torrefaction gases are assumed to be captured and combusted in order to provide heat for the torrefaction process. However, combustion of these gases generates various air quality pollutants, which are emitted to the atmosphere. **Table B-11** provides a summary of the various emissions that are emitted during the torrefaction process.

Table B-11: Airborne Emissions from Torrefaction Operations (kg/kg Torrefied Biomass Produced)

Airborne Emission	Value
Carbon Dioxide (CO_2)	6.98E-02
Methane (CH_4)	5.62E-07
Nitrous Oxide (N_2O)	5.38E-07
Particulate Matter (PM_{10})	1.86E-06
Carbon Monoxide (CO)	9.59E-05
Ammonia (NH_3)	7.82E-07
Nitrogen Oxides (NO_X)	6.84E-05
Sulfur Oxides (SO_x)	1.47E-07
Non-Methane Volatile Organic Carbons	1.34E-06
Lead (Pb)	2.44E-08
Mercury (Hg)	1.27E-08

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Appendix C: Detailed Results

List of Tables

Table C-1: Full LCA Results by Life Cycle Stage

Category (Units)	Material or Energy Flow	100% Illinois No. 6 Coal					10% Hybrid Poplar					10% Forest Residue				
		RMA	RMT	ECF	T&D	Total	RMA	RMT	ECF	T&D	Total	RMA	RMT	ECF	T&D	Total
GHG (kg/MWh)	CO_2	1.14E+01	5.71E+00	1.00E+03	0.00E+00	1.02E+03	-4.43E+01	5.57E+00	1.04E+03	0.00E+00	9.97E+02	-9.21E+01	5.57E+00	1.04E+03	0.00E+00	9.50E+02
	N_2O	2.00E-04	1.39E-04	6.91E-08	0.00E+00	3.40E-04	5.05E-02	1.36E-04	2.17E-04	0.00E+00	5.08E-02	2.95E-04	1.36E-04	2.17E-04	0.00E+00	6.48E-04
	CH_4	3.86E+00	6.59E-03	1.01E-06	0.00E+00	3.87E+00	3.52E+00	7.08E-03	1.26E-01	0.00E+00	3.65E+00	3.51E+00	7.08E-03	1.26E-01	0.00E+00	3.64E+00
	SF_6	2.05E-06	2.34E-11	0.00E+00	1.43E-04	1.45E-04	1.94E-06	2.60E-11	1.61E-06	1.43E-04	1.47E-04	1.86E-06	2.60E-11	1.61E-06	1.43E-04	1.47E-04
	CO_2e (IPCC 2007 100-yr GWP)	1.08E+02	5.92E+00	1.00E+03	3.27E+00	1.12E+03	5.87E+01	5.78E+00	1.04E+03	3.27E+00	1.11E+03	-4.28E+00	5.78E+00	1.04E+03	3.27E+00	1.04E+03
Other Air (kg/MWh)	Pb	1.49E-06	6.47E-08	2.64E-09	0.00E+00	1.55E-06	3.05E-06	1.18E-07	1.25E-07	0.00E+00	3.30E-06	1.57E-06	1.18E-07	1.25E-07	0.00E+00	1.81E-06
	Hg	2.65E-07	5.11E-09	3.76E-05	0.00E+00	3.79E-05	3.62E-07	8.08E-09	3.43E-05	0.00E+00	3.46E-05	2.54E-07	8.08E-09	3.43E-05	0.00E+00	3.45E-05
	NH_3	2.54E-05	2.00E-04	0.00E+00	0.00E+00	2.26E-04	8.47E-03	1.84E-04	7.29E-06	0.00E+00	8.67E-03	3.27E-05	1.84E-04	7.29E-06	0.00E+00	2.24E-04
	CO	1.00E-02	1.68E-02	1.53E+00	0.00E+00	1.55E+00	3.53E-02	1.63E-02	1.44E+00	0.00E+00	1.50E+00	2.51E-02	1.63E-02	1.44E+00	0.00E+00	1.49E+00
	NO_x	1.68E-02	1.41E-02	1.07E+00	0.00E+00	1.10E+00	4.05E-02	1.31E-02	9.28E-01	0.00E+00	9.81E-01	1.83E-02	1.31E-02	9.28E-01	0.00E+00	9.59E-01
	SO_x	3.33E-02	5.52E-03	4.12E-01	0.00E+00	4.51E-01	4.70E-02	5.88E-03	4.00E-01	0.00E+00	4.53E-01	3.33E-02	5.88E-03	4.00E-01	0.00E+00	4.39E-01
	VOC	2.87E-03	2.61E-03	-5.16E-15	0.00E+00	5.49E-03	5.00E+00	2.79E-03	3.30E-02	0.00E+00	5.04E+00	4.71E-03	2.79E-03	3.30E-02	0.00E+00	4.05E-02
	PM	1.49E-03	1.79E-02	2.60E-01	0.00E+00	2.79E-01	7.61E-02	1.63E-02	2.41E-01	0.00E+00	3.33E-01	6.79E-02	1.63E-02	2.41E-01	0.00E+00	3.25E-01
Solid Waste (kg/MWh)	Heavy Metals to Industrial Soil	6.42E-02	6.06E-05	0.00E+00	0.00E+00	6.42E-02	6.10E-02	6.67E-05	5.03E-02	0.00E+00	1.11E-01	5.82E-02	6.67E-05	5.03E-02	0.00E+00	1.09E-01
	Heavy Metals to Agricultural Soil	6.32E-16	0.00E+00	0.00E+00	0.00E+00	6.32E-16	1.54E-03	0.00E+00	0.00E+00	0.00E+00	1.54E-03	5.73E-16	0.00E+00	0.00E+00	0.00E+00	5.73E-16
Water Use (L/MWh)	Water withdrawal	4.92E+02	4.90E+00	2.70E+03	0.00E+00	3.20E+03	4.86E+04	5.79E+00	2.98E+03	0.00E+00	5.16E+04	4.49E+02	5.79E+00	2.98E+03	0.00E+00	3.43E+03
	Water discharge	7.42E+02	1.94E+00	6.09E+02	0.00E+00	1.35E+03	6.93E+02	2.14E+00	8.59E+02	0.00E+00	1.55E+03	6.73E+02	2.14E+00	8.59E+02	0.00E+00	1.53E+03
	Water consumption	-2.50E+02	2.96E+00	2.09E+03	0.00E+00	1.85E+03	4.80E+04	3.65E+00	2.12E+03	0.00E+00	5.01E+04	-2.24E+02	3.65E+00	2.12E+03	0.00E+00	1.90E+03
Water Quality (kg/MWh)	Aluminum	6.03E-05	6.70E-04	0.00E+00	0.00E+00	7.30E-04	6.36E-04	7.11E-04	1.15E-05	0.00E+00	1.36E-03	6.02E-04	7.11E-04	1.15E-05	0.00E+00	1.32E-03
	Arsenic (+V)	1.63E-05	1.91E-05	0.00E+00	0.00E+00	3.54E-05	3.37E-05	2.03E-05	1.18E-05	0.00E+00	6.57E-05	3.04E-05	2.03E-05	1.18E-05	0.00E+00	6.25E-05
	Copper (+II)	1.99E-05	2.80E-05	0.00E+00	0.00E+00	4.78E-05	5.18E-05	2.97E-05	1.41E-05	0.00E+00	9.56E-05	4.09E-05	2.97E-05	1.41E-05	0.00E+00	8.46E-05
	Iron	5.08E-04	1.47E-03	4.30E-08	0.00E+00	1.98E-03	2.14E-03	1.57E-03	2.42E-04	0.00E+00	3.96E-03	1.63E-03	1.57E-03	2.42E-04	0.00E+00	3.44E-03
	Lead (+II)	5.57E-06	6.43E-05	5.48E-10	0.00E+00	6.98E-05	6.84E-05	6.82E-05	7.30E-07	0.00E+00	1.37E-04	5.76E-05	6.82E-05	7.30E-07	0.00E+00	1.27E-04
	Manganese (+II)	2.31E-05	2.17E-07	0.00E+00	0.00E+00	2.33E-05	2.25E-05	2.40E-07	9.97E-05	0.00E+00	1.23E-04	2.10E-05	2.40E-07	9.97E-05	0.00E+00	1.21E-04
	Nickel (+II)	7.21E-04	5.08E-04	7.44E-11	0.00E+00	1.23E-03	1.13E-03	5.40E-04	5.38E-04	0.00E+00	2.20E-03	1.07E-03	5.40E-04	5.38E-04	0.00E+00	2.15E-03
	Strontium	7.85E-07	6.48E-07	0.00E+00	0.00E+00	1.43E-06	2.81E-06	7.36E-07	3.94E-07	0.00E+00	3.94E-06	1.09E-06	7.36E-07	3.94E-07	0.00E+00	2.22E-06
	Zinc (+II)	2.53E-04	8.82E-04	3.27E-10	0.00E+00	1.14E-03	1.01E-03	9.37E-04	1.52E-04	0.00E+00	2.10E-03	9.51E-04	9.37E-04	1.52E-04	0.00E+00	2.04E-03
	Ammonium/Ammonia	2.21E-03	7.24E-03	4.18E-08	0.00E+00	9.46E-03	1.07E-02	7.69E-03	1.34E-03	0.00E+00	1.98E-02	7.94E-03	7.69E-03	1.34E-03	0.00E+00	1.70E-02
	Hydrogen chloride	1.35E-10	1.93E-10	0.00E+00	0.00E+00	3.28E-10	3.75E-10	2.06E-10	9.17E-11	0.00E+00	6.73E-10	2.69E-10	2.06E-10	9.17E-11	0.00E+00	5.67E-10
	Nitrogen (as total N)	8.93E-05	2.61E-08	0.00E+00	0.00E+00	8.93E-05	9.92E-04	9.83E-07	9.97E-05	0.00E+00	1.09E-03	8.09E-05	9.83E-07	9.97E-05	0.00E+00	1.82E-04
	Phosphate	1.33E-07	6.53E-08	0.00E+00	0.00E+00	1.98E-07	4.08E-06	9.67E-08	4.48E-08	0.00E+00	4.22E-06	1.38E-07	9.67E-08	4.48E-08	0.00E+00	2.79E-07
	Phosphorus	5.83E-05	6.39E-04	4.48E-09	0.00E+00	6.97E-04	8.29E-03	6.79E-04	1.03E-05	0.00E+00	8.98E-03	5.76E-04	6.79E-04	1.03E-05	0.00E+00	1.27E-03
Resource Energy (MJ/MWh)	Crude oil	1.08E+01	5.91E+01	2.92E-03	0.00E+00	6.99E+01	7.51E+01	6.31E+01	2.83E+00	0.00E+00	1.41E+02	5.77E+01	6.31E+01	2.83E+00	0.00E+00	1.24E+02
	Hard coal	1.19E+04	1.63E+00	1.27E-02	0.00E+00	1.19E+04	1.08E+04	1.97E+00	2.45E+01	0.00E+00	1.08E+04	1.08E+04	1.97E+00	2.45E+01	0.00E+00	1.08E+04
	Lignite	5.52E-02	2.80E-01	0.00E+00	0.00E+00	3.35E-01	2.58E+00	3.19E-01	1.28E-02	0.00E+00	2.91E+00	7.57E-02	3.19E-01	1.28E-02	0.00E+00	4.08E-01
	Natural gas	4.59E+01	7.16E+00	2.54E-03	0.00E+00	5.30E+01	1.45E+02	7.94E+00	3.01E+02	0.00E+00	4.53E+02	4.71E+01	7.94E+00	3.01E+02	0.00E+00	3.56E+02
	Uranium	2.44E-01	1.22E+00	0.00E+00	0.00E+00	1.47E+00	4.35E+00	1.36E+00	4.74E-02	0.00E+00	5.76E+00	5.62E-01	1.36E+00	4.74E-02	0.00E+00	1.97E+00
	Biomass	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.18E+03	0.00E+00	0.00E+00	0.00E+00	1.18E+03	1.18E+03	0.00E+00	0.00E+00	0.00E+00	1.18E+03
	Total Resource Energy	1.19E+04	6.94E+01	1.82E-02	0.00E+00	1.20E+04	1.22E+04	7.47E+01	3.28E+02	0.00E+00	1.26E+04	1.20E+04	7.47E+01	3.28E+02	0.00E+00	1.25E+04
Energy Return on Investment		N/A	N/A	N/A	N/A	0.43:1	N/A	N/A	N/A	N/A	0.40:1	N/A	N/A	N/A	N/A	0.41:1

Table C-2: Full LCA Results by Life Cycle Stage (Alternate Units)

Category (Units)	Material or Energy Flow	100% Illinois No. 6 Coal					10% Hybrid Poplar					10% Forest Residue				
		RMA	RMT	ECF	T&D	Total	RMA	RMT	ECF	T&D	Total	RMA	RMT	ECF	T&D	Total
GHG (lb/MWh)	CO_2	2.52E+01	1.26E+01	2.21E+03	0.00E+00	2.24E+03	-9.76E+01	1.23E+01	2.28E+03	0.00E+00	2.20E+03	-2.03E+02	1.23E+01	2.28E+03	0.00E+00	2.09E+03
	N_2O	4.42E-04	3.07E-04	1.52E-07	0.00E+00	7.49E-04	1.11E-01	2.99E-04	4.79E-04	0.00E+00	1.12E-01	6.51E-04	2.99E-04	4.79E-04	0.00E+00	1.43E-03
	CH_4	8.52E+00	1.45E-02	2.23E-06	0.00E+00	8.53E+00	7.75E+00	1.56E-02	2.77E-01	0.00E+00	8.04E+00	7.73E+00	1.56E-02	2.77E-01	0.00E+00	8.02E+00
	SF_6	4.52E-06	5.17E-11	0.00E+00	3.16E-04	3.20E-04	4.28E-06	5.73E-11	3.55E-06	3.16E-04	3.24E-04	4.10E-06	5.73E-11	3.55E-06	3.16E-04	3.24E-04
	CO_2e (IPCC 2007 100-yr GWP)	2.38E+02	1.30E+01	2.21E+03	7.20E+00	2.46E+03	1.29E+02	1.27E+01	2.29E+03	7.20E+00	2.44E+03	-9.43E+00	1.27E+01	2.29E+03	7.20E+00	2.30E+03
Other Air (lb/MWh)	Pb	3.28E-06	1.43E-07	5.81E-09	0.00E+00	3.43E-06	6.73E-06	2.61E-07	2.75E-07	0.00E+00	7.27E-06	3.46E-06	2.61E-07	2.75E-07	0.00E+00	4.00E-06
	Hg	5.84E-07	1.13E-08	8.29E-05	0.00E+00	8.35E-05	7.97E-07	1.78E-08	7.55E-05	0.00E+00	7.63E-05	5.61E-07	1.78E-08	7.55E-05	0.00E+00	7.61E-05
	NH_3	5.61E-05	4.41E-04	0.00E+00	0.00E+00	4.98E-04	1.87E-02	4.06E-04	1.61E-05	0.00E+00	1.91E-02	7.20E-05	4.06E-04	1.61E-05	0.00E+00	4.94E-04
	CO	2.21E-02	3.71E-02	3.37E+00	0.00E+00	3.43E+00	7.77E-02	3.60E-02	3.19E+00	0.00E+00	3.30E+00	5.54E-02	3.60E-02	3.19E+00	0.00E+00	3.28E+00
	NO_x	3.71E-02	3.10E-02	2.36E+00	0.00E+00	2.43E+00	8.93E-02	2.89E-02	2.05E+00	0.00E+00	2.16E+00	4.04E-02	2.89E-02	2.05E+00	0.00E+00	2.11E+00
	SO_x	7.33E-02	1.22E-02	9.09E-01	0.00E+00	9.94E-01	1.04E-01	1.30E-02	8.81E-01	0.00E+00	9.98E-01	7.34E-02	1.30E-02	8.81E-01	0.00E+00	9.67E-01
	VOC	6.33E-03	5.77E-03	-1.14E-14	0.00E+00	1.21E-02	1.10E+01	6.16E-03	7.28E-02	0.00E+00	1.11E+01	1.04E-02	6.16E-03	7.28E-02	0.00E+00	8.94E-02
	PM	3.29E-03	3.95E-02	5.73E-01	0.00E+00	6.15E-01	1.68E-01	3.60E-02	5.31E-01	0.00E+00	7.35E-01	1.50E-01	3.60E-02	5.31E-01	0.00E+00	7.17E-01
Solid Waste (lb/MWh)	Heavy Metals to Industrial Soil	1.41E-01	1.34E-04	0.00E+00	0.00E+00	1.42E-01	1.34E-01	1.47E-04	1.11E-01	0.00E+00	2.46E-01	1.28E-01	1.47E-04	1.11E-01	0.00E+00	2.39E-01
	Heavy Metals to Agricultural Soil	1.39E-15	0.00E+00	0.00E+00	0.00E+00	1.39E-15	3.39E-03	0.00E+00	0.00E+00	0.00E+00	3.39E-03	1.26E-15	0.00E+00	0.00E+00	0.00E+00	1.26E-15
Water Use (gal/MWh)	Water withdrawal	1.30E+02	1.29E+00	7.14E+02	0.00E+00	8.45E+02	1.29E+04	1.53E+00	7.87E+02	0.00E+00	1.36E+04	1.19E+02	1.53E+00	7.87E+02	0.00E+00	9.07E+02
	Water discharge	1.96E+02	5.13E-01	1.61E+02	0.00E+00	3.57E+02	1.83E+02	5.66E-01	2.27E+02	0.00E+00	4.11E+02	1.78E+02	5.66E-01	2.27E+02	0.00E+00	4.05E+02
	Water consumption	-6.60E+01	7.81E-01	5.53E+02	0.00E+00	4.88E+02	1.27E+04	9.64E-01	5.60E+02	0.00E+00	1.32E+04	-5.91E+01	9.64E-01	5.60E+02	0.00E+00	5.02E+02
Water Quality (lb/MWh)	Aluminum	1.33E-04	1.48E-03	0.00E+00	0.00E+00	1.61E-03	1.40E-03	1.57E-03	2.54E-05	0.00E+00	3.00E-03	1.33E-03	1.57E-03	2.54E-05	0.00E+00	2.92E-03
	Arsenic (+V)	3.60E-05	4.21E-05	0.00E+00	0.00E+00	7.81E-05	7.42E-05	4.47E-05	2.60E-05	0.00E+00	1.45E-04	6.71E-05	4.47E-05	2.60E-05	0.00E+00	1.38E-04
	Copper (+II)	4.38E-05	6.16E-05	0.00E+00	0.00E+00	1.05E-04	1.14E-04	6.54E-05	3.10E-05	0.00E+00	2.11E-04	9.01E-05	6.54E-05	3.10E-05	0.00E+00	1.87E-04
	Iron	1.12E-03	3.25E-03	9.48E-08	0.00E+00	4.37E-03	4.73E-03	3.46E-03	5.33E-04	0.00E+00	8.72E-03	3.59E-03	3.46E-03	5.33E-04	0.00E+00	7.58E-03
	Lead (+II)	1.23E-05	1.42E-04	1.21E-09	0.00E+00	1.54E-04	1.51E-04	1.50E-04	1.61E-06	0.00E+00	3.03E-04	1.27E-04	1.50E-04	1.61E-06	0.00E+00	2.79E-04
	Manganese (+II)	5.09E-05	4.78E-07	0.00E+00	0.00E+00	5.14E-05	4.97E-05	5.29E-07	2.20E-04	0.00E+00	2.70E-04	4.63E-05	5.29E-07	2.20E-04	0.00E+00	2.67E-04
	Nickel (+II)	1.59E-03	1.12E-03	1.64E-10	0.00E+00	2.71E-03	2.48E-03	1.19E-03	1.19E-03	0.00E+00	4.86E-03	2.36E-03	1.19E-03	1.19E-03	0.00E+00	4.73E-03
	Strontium	1.73E-06	1.43E-06	0.00E+00	0.00E+00	3.16E-06	6.20E-06	1.62E-06	8.68E-07	0.00E+00	8.69E-06	2.41E-06	1.62E-06	8.68E-07	0.00E+00	4.90E-06
	Zinc (+II)	5.58E-04	1.95E-03	7.22E-10	0.00E+00	2.50E-03	2.22E-03	2.06E-03	3.34E-04	0.00E+00	4.62E-03	2.10E-03	2.06E-03	3.34E-04	0.00E+00	4.50E-03
	Ammonium/Ammonia	4.88E-03	1.60E-02	9.21E-08	0.00E+00	2.09E-02	2.37E-02	1.70E-02	2.95E-03	0.00E+00	4.36E-02	1.75E-02	1.70E-02	2.95E-03	0.00E+00	3.74E-02
	Hydrogen chloride	2.97E-10	4.25E-10	0.00E+00	0.00E+00	7.23E-10	8.27E-10	4.55E-10	2.02E-10	0.00E+00	1.48E-09	5.93E-10	4.55E-10	2.02E-10	0.00E+00	1.25E-09
	Nitrogen (as total N)	1.97E-04	5.75E-08	0.00E+00	0.00E+00	1.97E-04	2.19E-03	2.17E-06	2.20E-04	0.00E+00	2.41E-03	1.78E-04	2.17E-06	2.20E-04	0.00E+00	4.00E-04
	Phosphate	2.93E-07	1.44E-07	0.00E+00	0.00E+00	4.38E-07	8.99E-06	2.13E-07	9.87E-08	0.00E+00	9.30E-06	3.04E-07	2.13E-07	9.87E-08	0.00E+00	6.16E-07
	Phosphorus	1.29E-04	1.41E-03	9.87E-09	0.00E+00	1.54E-03	1.83E-02	1.50E-03	2.28E-05	0.00E+00	1.98E-02	1.27E-03	1.50E-03	2.28E-05	0.00E+00	2.79E-03
Resource Energy (Btu/MWh)	Crude oil	1.02E+04	5.60E+04	2.77E+00	0.00E+00	6.62E+04	7.12E+04	5.98E+04	2.69E+03	0.00E+00	1.34E+05	5.47E+04	5.98E+04	2.69E+03	0.00E+00	1.17E+05
	Hard coal	1.13E+07	1.55E+03	1.21E+01	0.00E+00	1.13E+07	1.02E+07	1.87E+03	2.32E+04	0.00E+00	1.02E+07	1.02E+07	1.87E+03	2.32E+04	0.00E+00	1.02E+07
	Lignite	5.23E+01	2.65E+02	0.00E+00	0.00E+00	3.17E+02	2.45E+03	3.03E+02	1.22E+01	0.00E+00	2.76E+03	7.17E+01	3.03E+02	1.22E+01	0.00E+00	3.87E+02
	Natural gas	4.35E+04	6.79E+03	2.41E+00	0.00E+00	5.03E+04	1.37E+05	7.52E+03	2.85E+05	0.00E+00	4.29E+05	4.47E+04	7.52E+03	2.85E+05	0.00E+00	3.37E+05
	Uranium	2.32E+02	1.16E+03	0.00E+00	0.00E+00	1.39E+03	4.12E+03	1.29E+03	4.49E+01	0.00E+00	5.46E+03	5.33E+02	1.29E+03	4.49E+01	0.00E+00	1.87E+03
	Biomass	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.12E+06	0.00E+00	0.00E+00	0.00E+00	1.12E+06	1.12E+06	0.00E+00	0.00E+00	0.00E+00	1.12E+06
	Total Resource Energy	1.13E+07	6.58E+04	1.72E+01	0.00E+00	1.14E+07	1.15E+07	7.08E+04	3.11E+05	0.00E+00	1.19E+07	1.14E+07	7.08E+04	3.11E+05	0.00E+00	1.18E+07
Energy Return on Investment		N/A	N/A	N/A	N/A	0.43:1	N/A	N/A	N/A	N/A	0.40:1	N/A	N/A	N/A	N/A	0.41:1