NATIONAL ENERGY TECHNOLOGY LABORATORY

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

Timothy J. Skone, P.E.
Senior Environmental Engineer
NETL Office of Strategic Energy Analysis and Planning

August 30, 2012

U.S. DEPARTMENT OF ENERGY

# Agenda

- Technology Description
- Resource, Capacity, and Growth
- Environmental Analysis
- Cost Analysis
- Barriers to Implementation
- Risks of Implementation
- Expert Opinions

# Technology Description: Coal and Biomass Co-firing

- **Co-fired power plants often burn coal and biomass with same mills and burners**
- **Most co-fired plants are retrofits to existing coal-fired systems**
- **As of 2005, there were four direct coal and biomass co-firing facilities that were operational in the U.S., along with at least 38 other coal power plants where coal/biomass co-firing had been tested (IEA, 2009)**

*Source: Dominion*

*Source: Dominion*

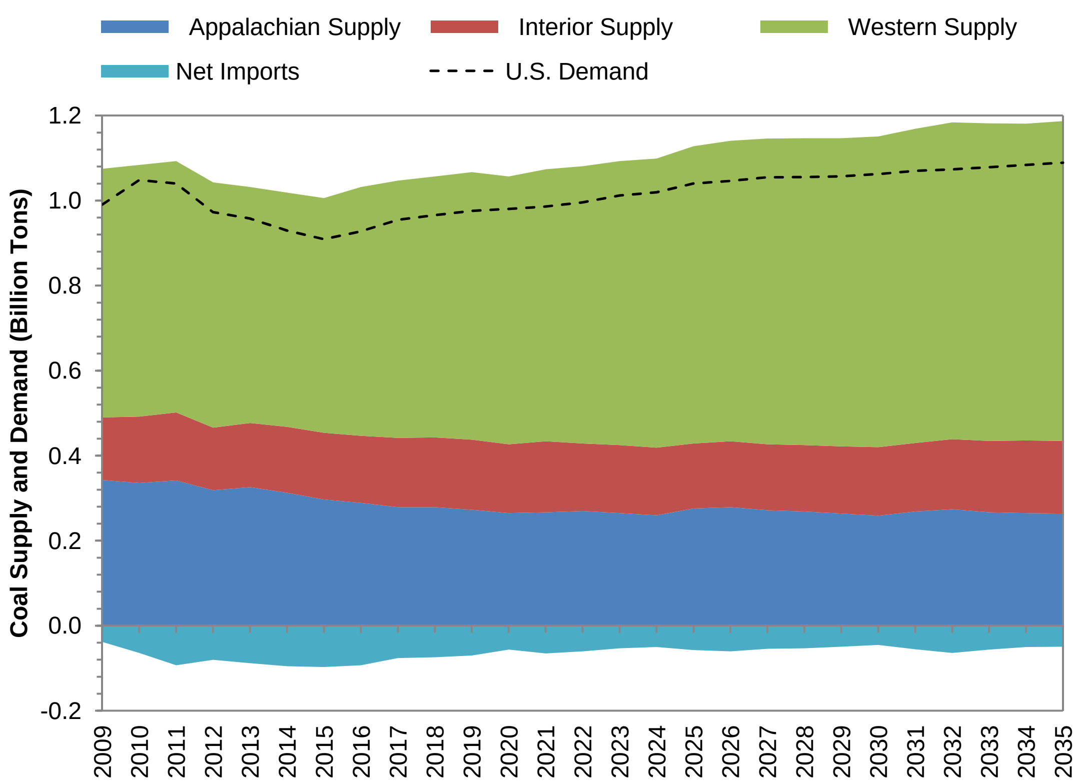
# Technology Description:
# Coal and Biomass Co-firing

- **Power plant has a PC boiler with a net output of 550 MW**
- **Net efficiency of coal-only power plant is 33% (equivalent to a heat rate of 10,909 kJ/kWh)**
- **Co-firing scenario is based on a feedstock input with 10% biomass by energy (equivalent to a net plant efficiency of 32.8%, 10,985 kJ/kWh)**
- **Environmental Controls**
  - Flue gas desulfurization (FGD) unit removes 98% of $SO_2$ emissions from flue gas
  - Electrostatic precipitator (ESP) unit removes particulate matter

| Parameter | Coal Only | Co-fired Coal and Biomass |
|---|---|---|
| Net Power, MWe | 550 | 550 |
| Net Plant Efficiency, % (HHV) | 33% | 32.8% |
| Net Plant Heat Rate, kJ/kWh | 10,907 | 10,983 |
| Capacity Factor, % | 85% | 85% |
| Coal, % Energy | 100% | 90% |
| Biomass, % Energy | 0% | 10% |
| **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 |

# Resource, 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**




**AEO 2012 Early Release Reference Case Coal Projections to 2035 (EIA, 2012)**

- 93% of U.S. coal demand is for electricity generation (EIA, 2012)

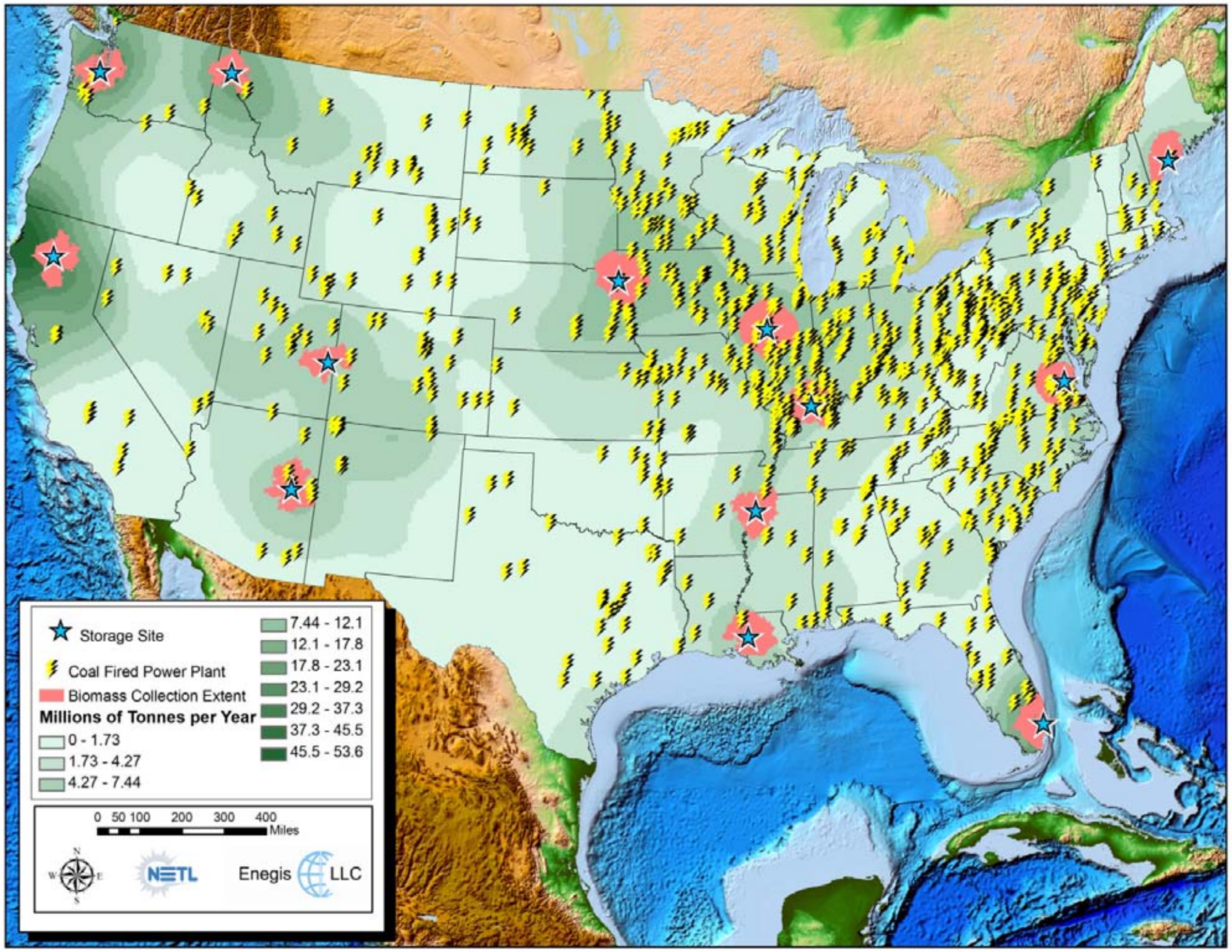
- Coal mines in the Western U.S. provide more than half of the U.S. coal supply (54% in 2011), followed by Appalachian and Interior mines (EIA, 2012)

- 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 (EIA, 2012)

# Resource, Capacity, and Growth

- **Three types of biomass that can be used for co-fired power are agricultural residues, forest residues and thinnings, and herbaceous and woody energy crops**
- **Agricultural residues**
  – Resource base of agricultural residues can be estimated by applying crop production statistics with residue-to-grain ratios (UTENN, 2010)
  – On a production basis, corn and wheat are largest crops in U.S. and have residue-to-grain ratios of 1 and 1.7, respectively (ORNL, 2011)
- **Forest residues and thinnings**
  – Most forest resources are used by 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
- **Herbaceous and woody energy crops**
  – Herbaceous Energy Crops: Switchgrass is often used as benchmark for herbaceous perennial energy crops and has been the focus of most of the research on herbaceous energy crops
  – Hybrid Poplar (HP): 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

# Resource, Capacity, and Growth




**Coal Plant and Biomass Resource Proximity Calculated by the BEAM Model (NETL, 2010)**

**Agricultural residues**

- Midwest states make up the majority of states with the ability to produce over 1 million dry tons of biomass per year (ORNL, 2011)
- $77 per delivered dry ton (Hess, Wright, Kenney, & Searcy, 2009)

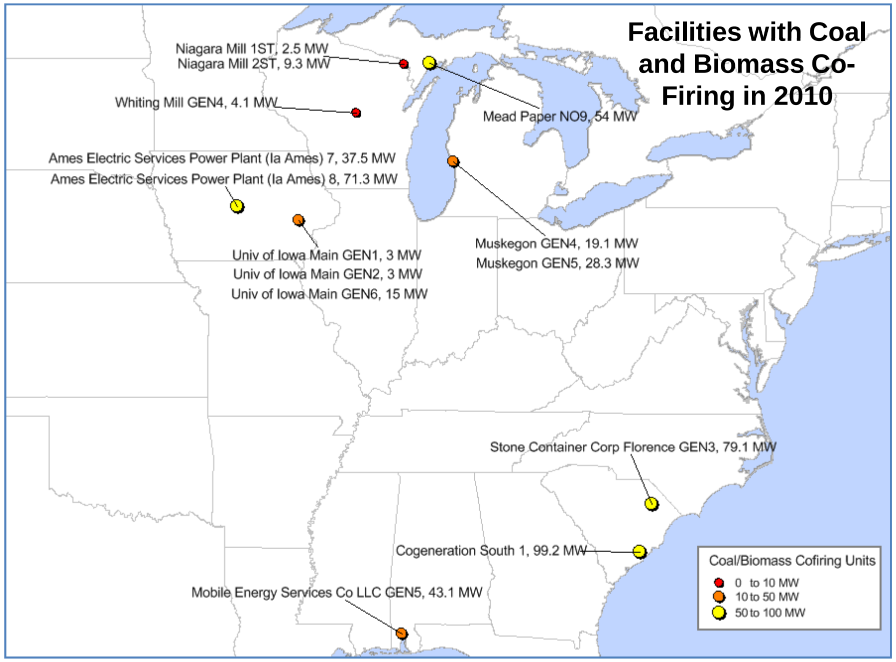
**Forest residues and thinnings**

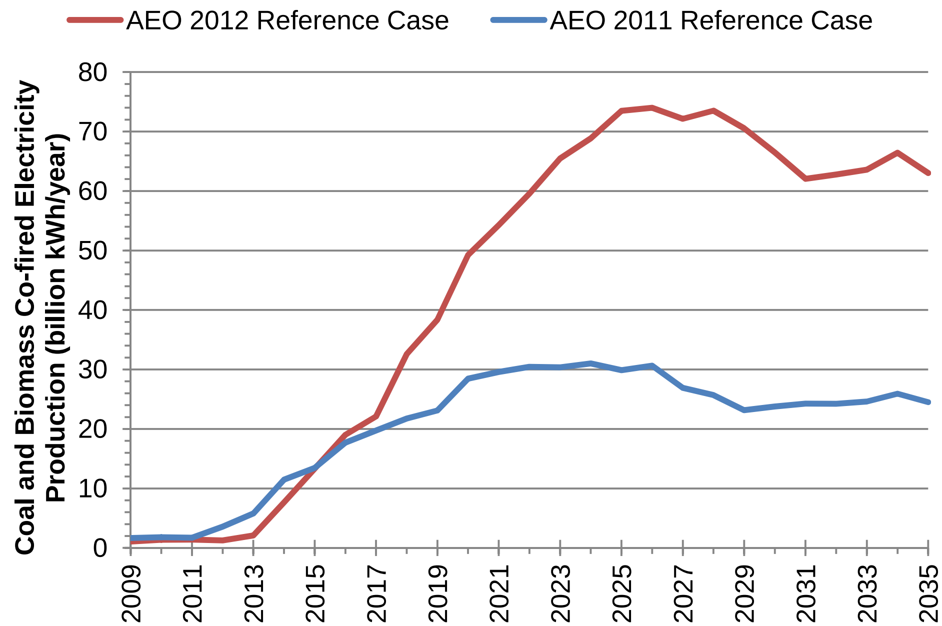
- Approximately 46,000 million dry tons of woody biomass can be produced annually at a roadside cost of $50 per dry ton

**Herbaceous and woody crops**

- Approximately 136 million dry tons of herbaceous energy crops can be produced annually based on the POLYSIS results for a 2030 scenario at a roadside cost of $50 per dry ton
- Approximately 62 million dry tons of short rotation woody crops can be produced annually in 2030 at a roadside cost of $50 per dry ton (ORNL, 2011)

# Resource, Capacity, and Growth



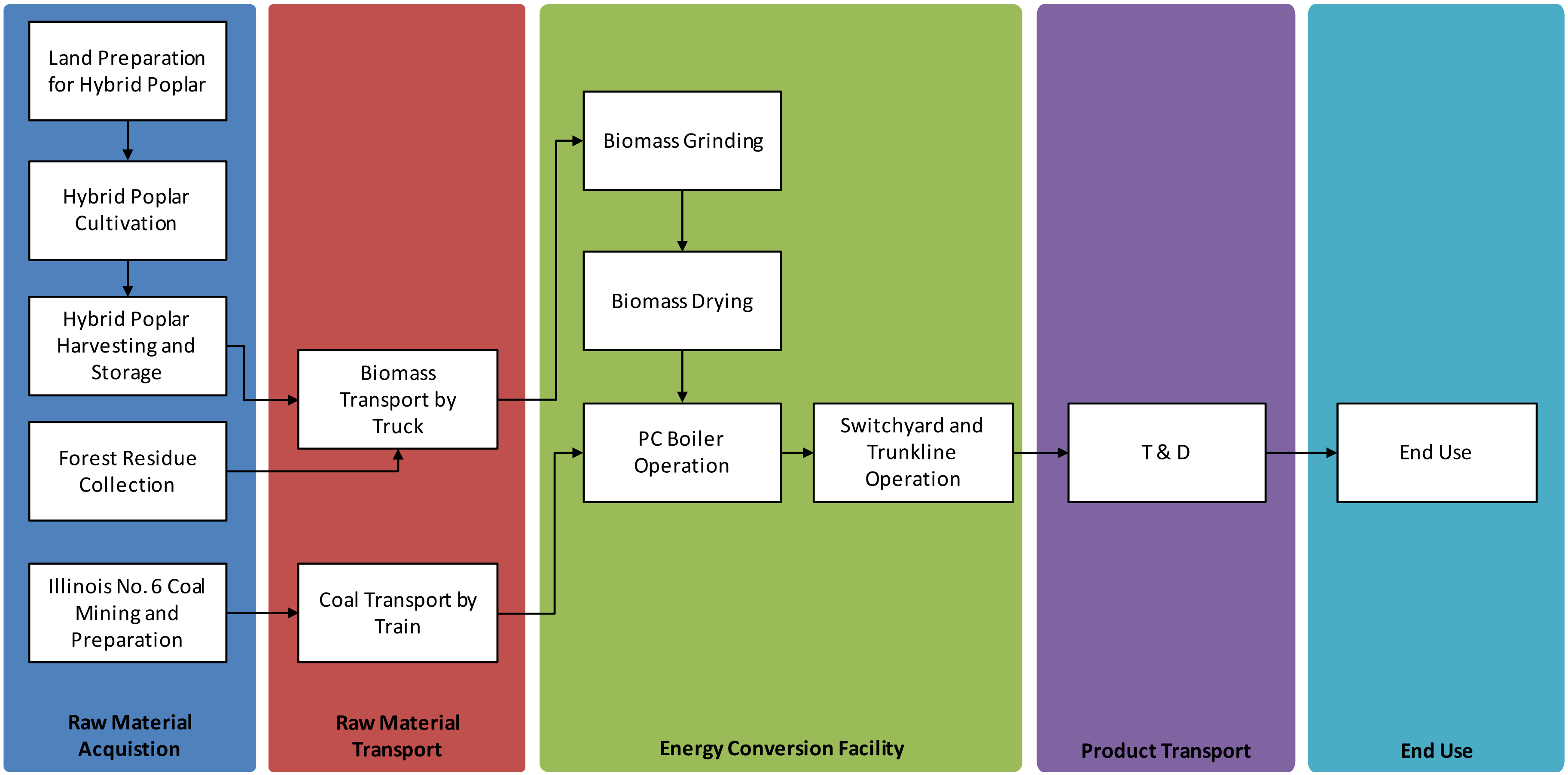

- In 2010, the combustion of biomass accounted for 11.5 billion kWh of electricity generation (EIA, 2012)
- The co-firing of coal and biomass in the U.S. generated 1.36 billion kWh of electricity in 2010 (0.32% of the 430 billion kWh renewable electricity generation and 0.03% of the 3,998 billion kWh total electricity generation) (EIA, 2012)

- The AEO 2011 reference case shows a peak of 31 billion kWh per year in 2024 (EIA, 2012)
- The AEO 2012 reference case is even more aggressive, showing a peak of 74 billion kWh per year in 2026 (EIA, 2012)
- 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%

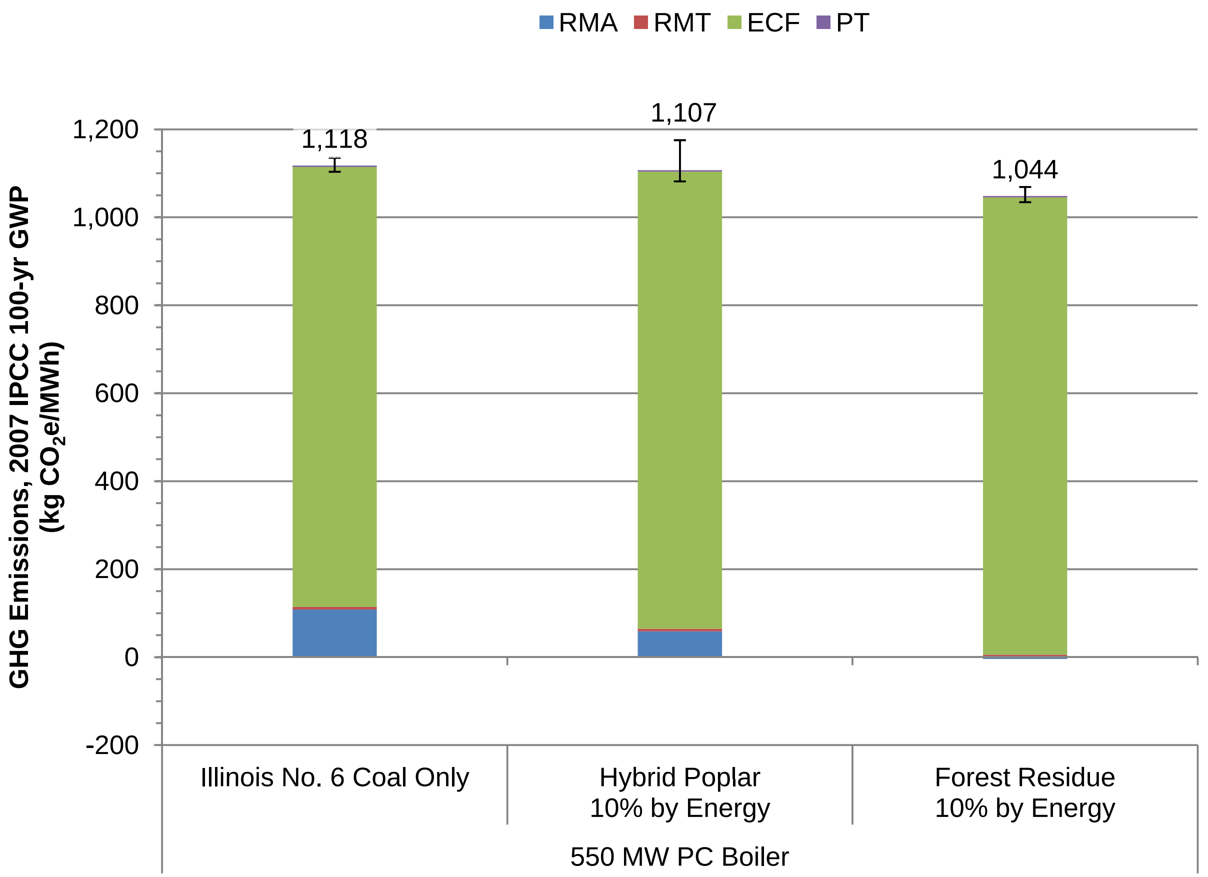
# Environmental Analysis of Co-firing

- **Life Cycle Analysis (LCA) completed for co-fired power**
  - Accounted for air emissions, water use and quality, and resource consumption
  - Based on a 550 MW pulverized coal boiler with a 33% efficiency
  - Feedstocks included Illinois No. 6 Coal, hybrid poplar, and forest residue
- **Model broken into life cycle stages:**
  - Stage 1: Raw Material Acquisition – Illinois No. 6 coal from minie, hybrid poplar from farm, and wood residue from forest
  - Stage 2: Raw Material Transport – road transport of biomass and rail transport of coal
  - Stage 3: Energy Conversion – operation of 550 MW power plant as well as biomass drying and grinding; construction of new, retrofitted equipment
  - Stage 4: Transmission and Distribution – grid transmission and associated loss of 7%
  - Stage 5: Electricity use by consumer – no losses or environmental burdens
- **Model comprised of interconnected network of modeled processes (unit processes)**

# Environmental Analysis of Co-firing: LCA Modeling Structure

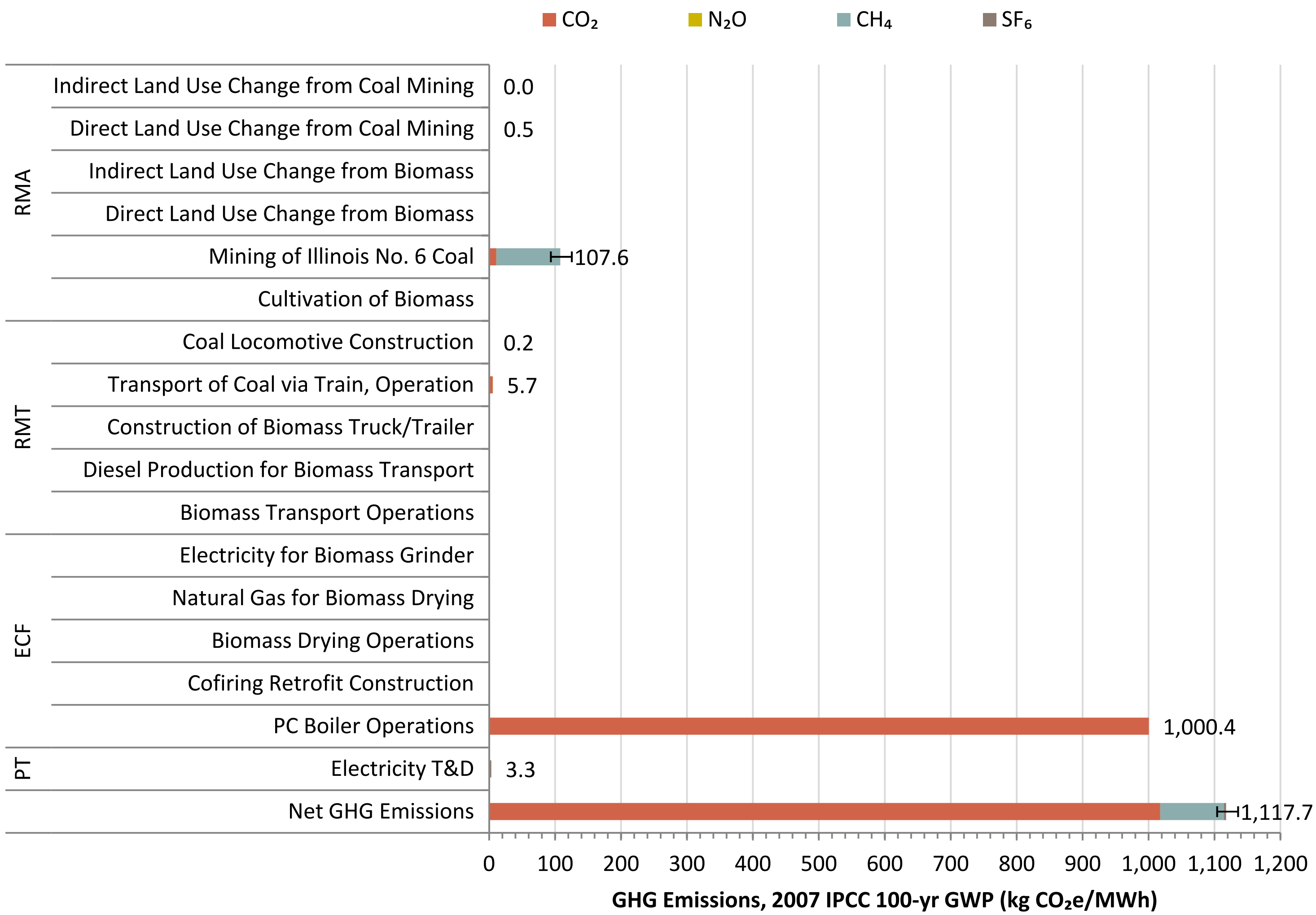


# Environmental Analysis: GHG Results



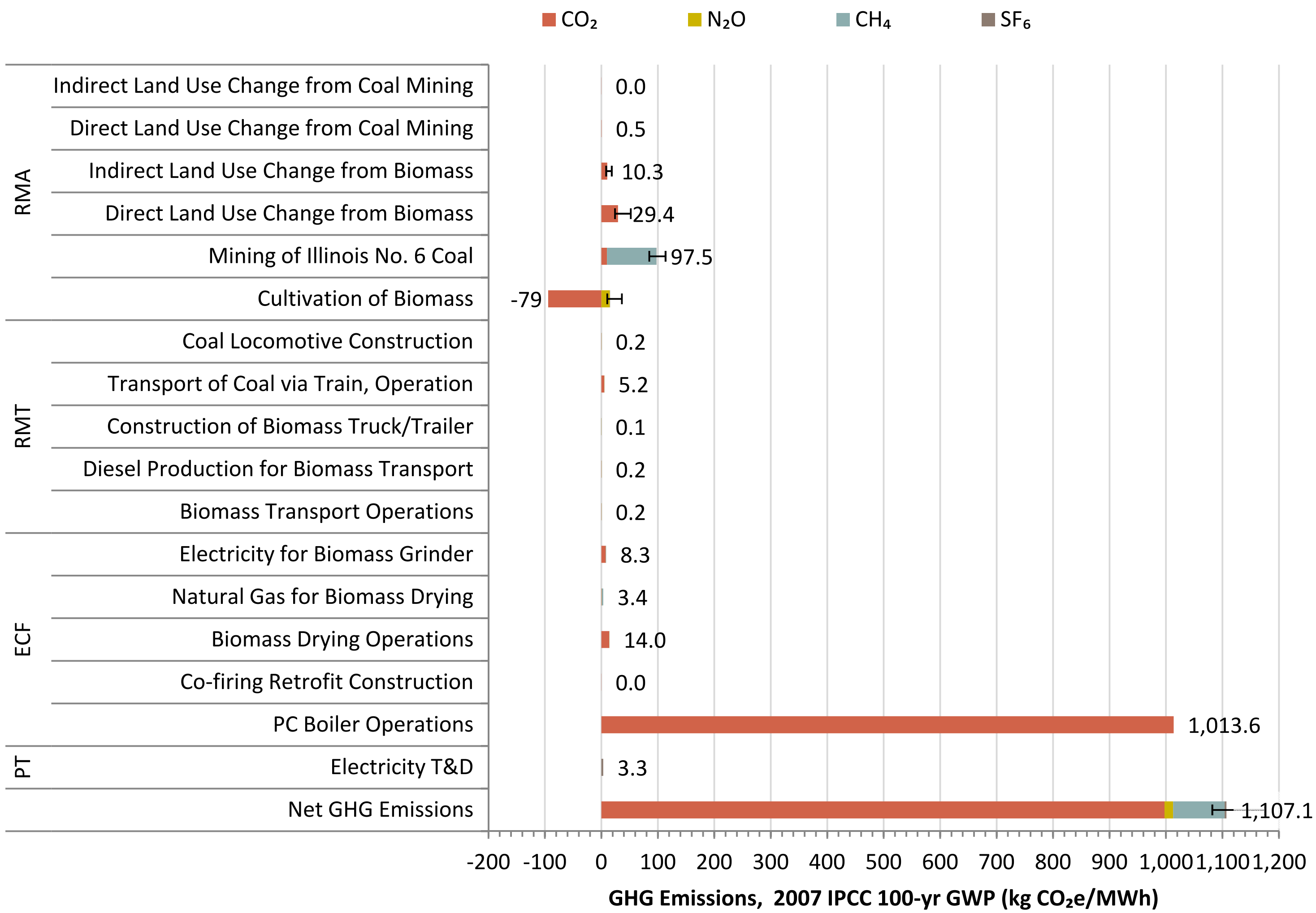

- The life cycle GHG emissions for the three scenarios range from 1,044 to 1,118 kg $CO_2$e/MWh
- The co-firing of forest residue has the lowest GHG emissions of this analysis because the acquisition of forest residue has relatively low GHG emissions from fuel combustion and does not incur GHG emissions from land transformation
- GHG emissions from land use are included in these results

# Environmental Analysis: GHG Results (100% Illinois No. 6 Coal)



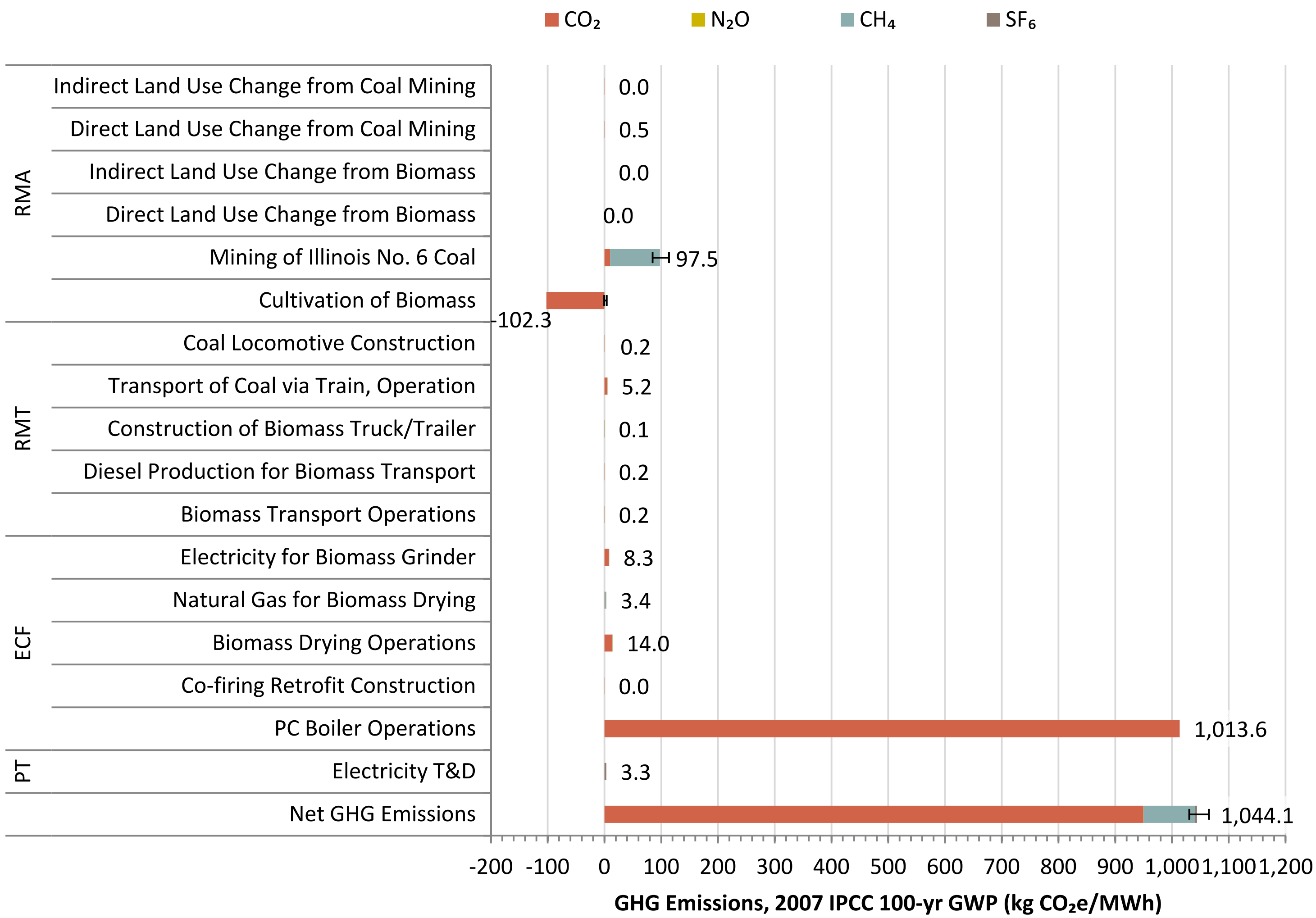

- GHG emissions dominated by PC Boiler Operations (90% of total GHG emissions)
- The mining of Illinois No. 6 coal produces 108 kg of $CO_2e$

# Environmental Analysis: GHG Results (10% Energy from Hybrid Poplar)



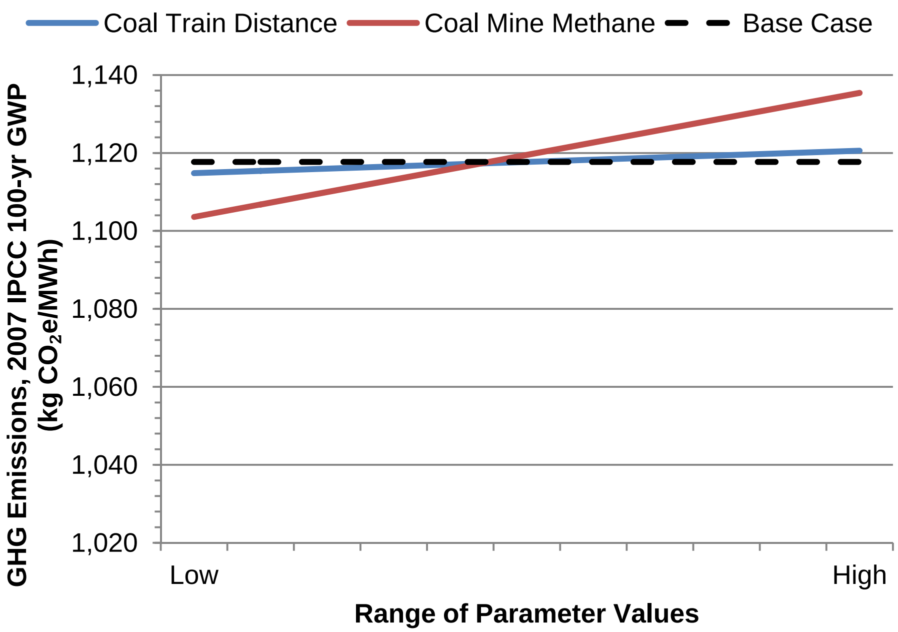

- GHG emissions dominated by PC Boiler Operations (92% of total GHG emissions)
- The mining of Illinois No. 6 coal produces 98 kg of $CO_2e$/MWh
- The co-firing of HP produces significant $N_2O$ emissions during biomass cultivation because its production and use of fertilizer produces significant $N_2O$ emissions
- Land use GHG emissions are included in RMA

# Environmental Analysis: GHG Results (10% Energy from Forest Residue)




- GHG emissions dominated by PC Boiler Operations (97% of total GHG emissions)
- The mining of Illinois No. 6 coal produces 102 kg of $CO_2$e/MWh
- Land use GHG emissions are included in RMA

# Environmental Analysis: Sensitivity (100% Illinois No. 6 Coal)

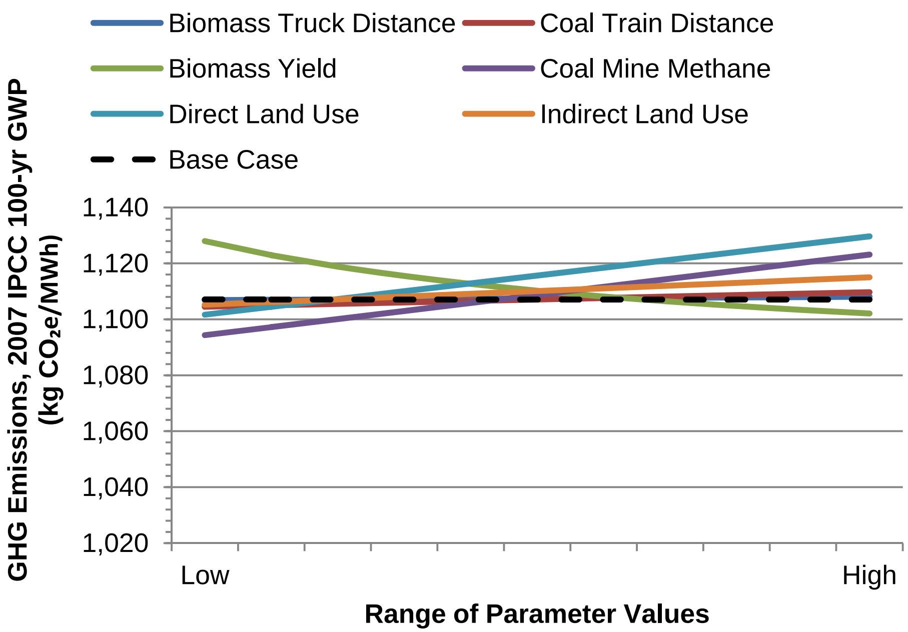



| Scenario | Parameter | Low | Expected Value | High |
|---|---|---|---|---|
| 100% Coal | Coal Train Distance, mi. | 200 | 400 | 600 |
| | Coal Mine Methane, scf/ton | 360 | 422 | 500 |
| **Scenario** | **Parameter** | **Low** | **Expected Value** | **High** |
| 100% Coal | Coal Train Distance, km | 322 | 644 | 966 |
| | Coal Mine Methane, $m^3$/tonne | 11.2 | 13.2 | 15.6 |

- The expected GHG value of 1,118 kg $CO_2$e/MWh is shown for reference
- Possible range of GHG results for the 100% coal scenario: 1,104 to 1,135 kg $CO_2$e/MWh depending on the value of the parameters

- The GHG results are more sensitive to the emission factor for coal mine methane than the transport distance for the coal train

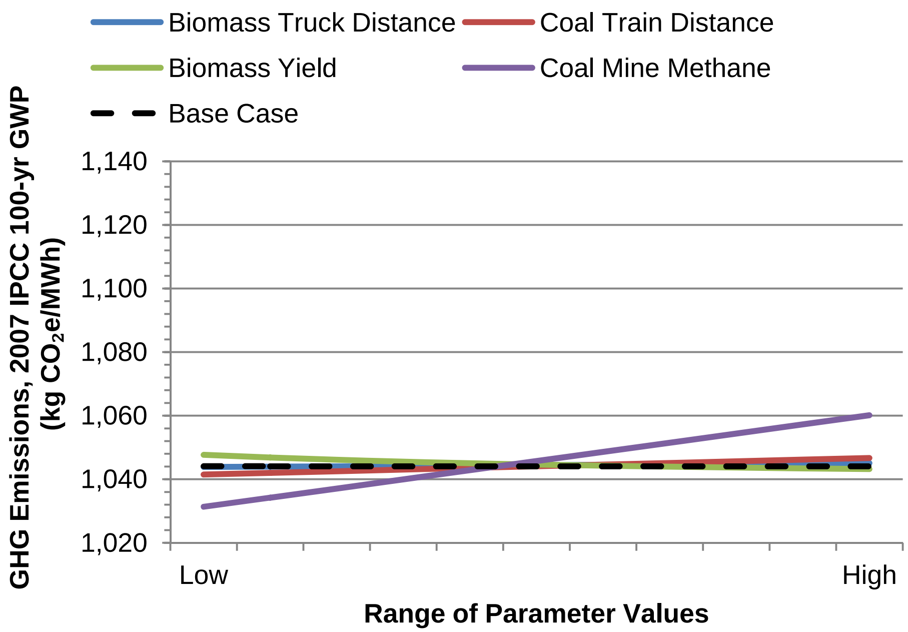
# Environmental Analysis: Sensitivity (10% Energy from Hybrid Poplar)




- The expected GHG value of 1,107 kg $CO_2$e/MWh is shown for reference
- Possible range of GHG results for the 10% hybrid poplar scenario: 1,094 to 1,130 kg $CO_2$e/MWh depending on the value of the parameters

| Scenario | Parameter | Low | Expected Value | High |
|---|---|---|---|---|
| 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. $CO_2$e/lb. | 0.215 | 0.264 | 0.466 |
| | Indirect Land Use, lb. $CO_2$e/lb. | 0.0755 | 0.0925 | 0.164 |
| **Scenario** | **Parameter** | **Low** | **Expected Value** | **High** |
| 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 $CO_2$e/kg | 0.215 | 0.264 | 0.466 |
| | Indirect Land Use, kg $CO_2$e/kg | 0.0755 | 0.0925 | 0.164 |

# Environmental Analysis: Sensitivity (10% Energy from Forest Residue)




| Scenario | Parameter | Low | Expected Value | High |
|---|---|---|---|---|
| 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** |
| 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 |

- The expected GHG value of 1,044 kg $CO_2$e/MWh is shown for reference
- Possible range of GHG results for 10% forest residue scenario: 1,031 to 1,060 kg $CO_2$e/MWh depending on the value of the parameters

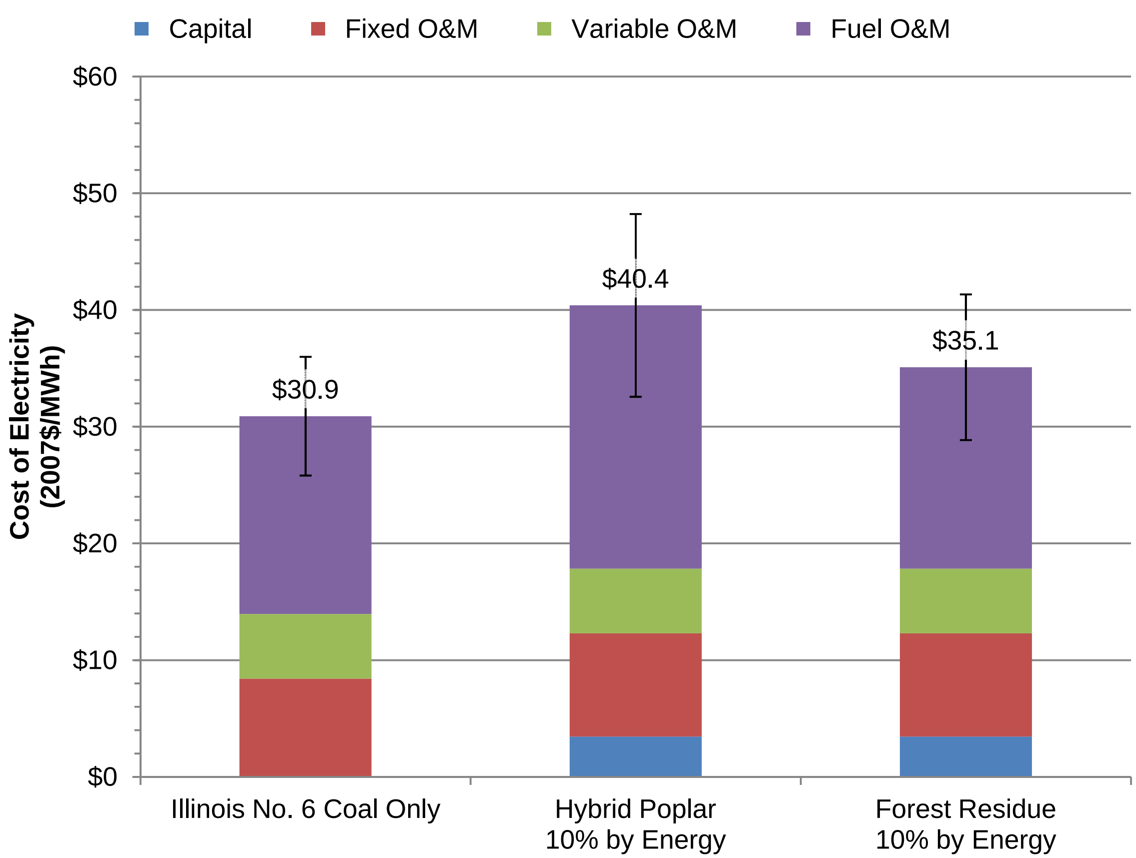
- The GHG emissions for the acquisition of forest residue are not significantly affected by biomass yield rate and have no GHG emissions from direct or indirect land use change
- Most GHG uncertainty and sensitivity is driven by the emission factor for coal-mine methane

# Cost Analysis: Financial and Cost Parameters

| 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 Costs) | 2007$/MWh | 7.65 | 7.65 | |

| 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 |

# Cost Analysis: Life Cycle Cost Results




- The COE of the three scenarios ranges from $30.9 to $40.4 per MWh (in 2007 dollars)
- The retrofit of an existing PC plant to co-fire HP increases the COE from $30.9/MWh to $40.4/MWh (a 31% increase)
- The COE for co-firing forest residue is $35.1/MWh (a 14% increase from the coal-only scenario)

# Barriers to Implementation

- **Adverse changes to the operating characteristics of boiler systems**
  - The moisture content of the 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
- **Unexpected changes in the biomass supply chain**
  - The uncertainties in the biomass supply chain are due to competing markets for both forest and herbaceous crops. Extreme weather conditions and other related natural forces can also cause supply disruptions or change the quality of biomass feedstocks
  - Land ownership issues can complicate the procurement of biomass feedstocks

# Risks of Implementation

- **Regulatory**
  - 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
  - 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
- **Supply-chain uncertainty**
  - Forest thinnings are a possible feedstock, but research is conflicting in terms of costs and benefits of forest thinning
  - Forest dynamics vary significantly from region to region, as do the environmental impacts or benefits of thinnings, and an associated regulatory environment has not matured in most states

# Expert Opinions

- **The long-term effects of biomass co-firing on installed process equipment are still not known**
  - 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. Most testing has been on a relatively short time-scale. In those tests, the impacts of mixing coal and biomass were minimal
- **No flexibility in the type of biomass to use for co-firing**
  - In most co-firing cases, plant managers must use locally sourced biomass
  - The type of biomass used by a power plant is a function of site-specific considerations and the local price and availability of fuels
- **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)
  - Only California and a region of New England have markets for RECs but they 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)

# References


EIA. (2012). AEO2012 Early Release Overview. (DOE/EIA-0383ER(2012)). U.S. Energy Information Administration Retrieved from http://www.eia.gov/forecasts/aeo/er/early_intensity.cfm

IEA. (2009). *International Energy Agency Bioenergy Task 32: Database of Biomass Co-firing Initiatives.*: International Energy Agency Retrieved from http://www.ieabcc.nl/database/co-firing.html

Hess, J. R., Wright, C. T., Kenney, K. L., & Searcy, E. M. (2009). Uniform-Format Bioenergy Feedstock Supply System Design Report Series: Commodity-Scale Production of an Infrastructure-Compatible Bulk Solid From Herbaceous Lignocellulosic Biomass. (INL/EXT-09-15423). Retrieved from http://www.inl.gov/portal-files/solid-feedstock-supply-system.pdf

NETL. (2010). Biomass Energy Analytical Model (BEAM). Pittsburgh, PA: National Energy Technology Laboratory.

ORNL. (2011). U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry. . U.S. Department of Energy, Energy Efficiency and Renewable Energy, Office of the Biomass Program Retrieved from http://www1.eere.energy.gov/biomass/pdfs/billion_ton_update.pdf

Ortiz, D. S., Curtright, A. e., Samaras, C., Litovitz, A., & Burger, N. (2011). Near-Term Opportunities for Integrating Biomass into the U.S. Electricity Supply. Santa Monica, CA: RAND Corporation Retrieved from http://www.rand.org/pubs/technical_reports/TR984.html

UTENN. (2010). POLYSYS. The University of Tennessee. Retrieved from http://www.agpolicy.org/polysys.html

# Contact Information


## Office of Fossil Energy

**www.fe.doe.gov**


## NETL

**www.netl.doe.gov**

**Timothy J. Skone, P.E.**
Senior Environmental Engineer
Office of Strategic Energy Analysis and Planning
(412) 386-4495
*timothy.skone@netl.doe.gov*

**Robert James, Ph.D.**
General Engineer
Office of Strategic Energy Analysis and Planning
(304) 285-4309
*robert.james@netl.doe.gov*

**Joe Marriott, Ph.D.**
Lead Associate
Booz Allen Hamilton
(412) 386-7557
*joseph.marriott@contr.netl.doe.gov*

**James Littlefield**
Associate
Booz Allen Hamilton
(412) 386-7560
*james.littlefield@contr.netl.doe.gov*