Methodology

This project employs chemical process design, techno-economic analysis (TEA), and life cycle assessment (LCA) to determine the economic cost and environmental impact of generating electricity from corn stover and coal via fast pyrolysis and combined heat and power systems. The chemical process design provides mass and energy balances of the major operating units and process modeled in this system. The TEA estimates the minimum electricity-selling price (MESP) for the facility based on its capital and operating costs. The LCA estimates the greenhouse gas emissions generated by this activity. Finally, we employ the results of this analysis to arrive at an incentive value for reducing coal electricity emissions via co-firing with bio-oil co-fire fuel.

Process Design

The overall process design consists of a fast pyrolysis unit coupled with a combined heat and power (CHP) generation unit. The major processing steps are shown in Figure 1. The system processing steps consist of pretreatment (chopping, drying, and grinding), pyrolysis gas cleanup and bio-oil recovery, storage, heat recovery and steam generation, and CHP.

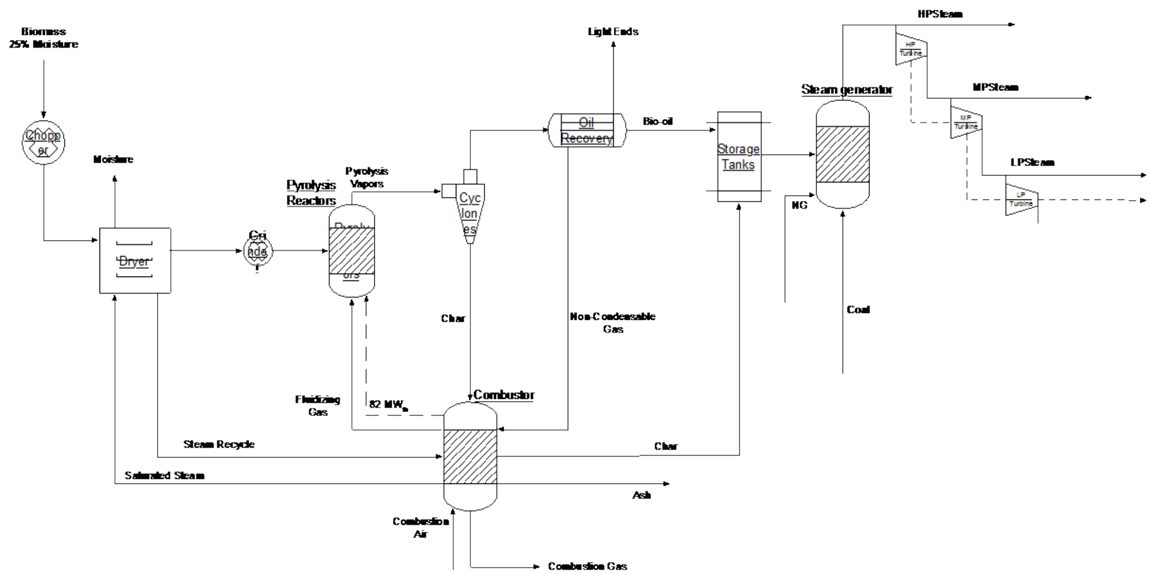


Figure 1 Simplified process flow diagram of corn stover fast pyrolysis and bio-oil co-fire fuel (BCF) and coal combined heat and power system

Biomass pretreatment includes chopping of the as-received stover to a screen size of 10 mm to improve its drying efficiency followed by grinding to 3 mm particle size. Drying takes place in a steam-blown drier operating at 120 °C designed to reduce the stover moisture content from 25% to 10%. The final feedstock properties (3 mm and 10% moisture) have been determined suitable for fast pyrolysis in a fluid bed reactor.

Fast pyrolysis takes place in a fluid bed reactor with operating conditions of 1 atm and 500 °C. Fluidization is accomplished by recycling flue gases from the combustion reactor at a 1.7 kg of gas to kg of feedstock input ratio. This study assumes that there are 4 fluid bed reactors operating in parallel. Heat input for the endothermic fast pyrolysis reactions is provided by indirect heat generated through pyrolysis gas and char combustion in the heat recovery and steam generation (HRSG) section. The fluid bed reactor yields pyrolysis vapors with entrained solids (biochar). Table 1 shows reported products yields of corn stover fast pyrolysis from various sources.

Table 1 Overall corn stover fast pyrolysis product yield comparison

Material Yields (wt. % dry basis)	NREL	NREL	USDA [a]
Non-Condensable Gas	14.3	11.7	21.9
Bio-oil	57.6	55.0	61.6[b]
Water	4.9	7.9	-
Biochar/Ash	19.4	19.5	17
Total	**96.2**	**94.1**	**100**

[a]Data employed by this study; [b]Includes water;

The facility employs cyclones to separate the solids from the vapor stream. Custom heat-exchanger units condense bio-oil from the pyrolysis vapors, and the remaining non-condensable gases (NCG) are sent to the HRSG section. The condensed bio-oil is later separated into heavy and light end phases.

Bio-oil contains hundreds of distinct organic compounds many of which have been identified in our laboratories. However, it remains difficult to model the quantities of these products. Therefore, the model employs representative compounds to account for the different compound groups in bio-oil. Table 2 shows the composition of pyrolysis products that serves as a basis for the model. These values are adjusted to improve the mole balance of the pyrolysis reactor.

Table 2 Pyrolysis product composition

Gas Compounds	Composition (kg/100 kg of dry biomass)
Carbon Dioxide	5.42
Carbon Monoxide	6.56
Methane	0.035
Ethane	0.142
Hydrogen	0.588[a]
Propane	0.152
Ammonia	0.0121
Bio-Oil Compounds	
Acetic Acid	5.93
Propionic Acid	7.31

Methoxyphenol	0.61
Ethylphenol	3.80
Formic Acid	3.41
Propyl-Benzoate	16.36
Phenol	0.46
Toluene	2.27
Furfural	18.98
Benzene	0.77
Other Compounds	
Water	10.80
Char/Ash	16.39

[a]Adjusted to 0.02 kg/kg of biomass based on engineering judgement.

The HRSG system provides heat and steam to the pyrolysis facility. The recovered heat provides energy for the endothermic pyrolysis reactor. Corn stover fast pyrolysis operates with a low energy input requirement and under pressurized conditions can operate exothermically. However, exothermic conditions are associated with higher biochar output and lower quality bio-oil yields. The primary use of the HRSG steam is to provide energy for feedstock drying. For this purpose, the HRSG raises low-pressure steam at 120 °C from the combustion of all non-condensable gases and a fraction of the biochar.

The primary purpose of this process is to generate steam and electricity from corn stover and coal. A secondary purpose of this design is to recover high value-added products from corn stover including biochar and bio-oil light ends. The overall outcome is the generation of electricity at a lower environmental impact than using coal alone with a competitive economic cost.

The final processing step is the CHP sub-system. The CHP employs both bio-oil co-fire fuel (BCF) and coal as input energy. The CHP boiler yields combustion gas at 1200 °C. The combustion gas passes through a series of heat exchangers to raise high-, medium-, and low-pressure steam. An economizer preheats water using excess heat from the boiler. A three-stage steam turbine system generates electricity for export at about 72% efficiency.

Feedstock Properties

Corn stover is used as the biomass of this analysis. Corn stover is modeled on a proximate and ultimate analysis basis. This process feedstock is modeled using information from Table 1. In summary, the modeled corn stover has a carbon content of 48.7 wt. % on a dry basis and negligible amounts of sulfur, which is relevant for the energy and environmental impact analysis. Biochar contains 75.7 wt. % carbon and the majority of inorganic metals required for agronomic applications. Coal is a bituminous coal with 63.7 wt. % carbon content and 2.51 wt.% sulfur.

Table 3 Corn stover, biochar, and bituminous coal ultimate and proximate analyses

Ultimate Analysis (dry basis)			
	Corn Stover	**Biochar**	**Bituminous Coal**
	Value (wt. %)	**Value (wt. %)**	**Value (wt. %)**
Ash	0.39	4.3	0.097
Carbon	48.7	75.7	0.6375
Hydrogen	6.8	4.2	0.045
Nitrogen	0.072	0.3	0.0125
Chlorine	0	0	0.0029
Sulfur	0.002	0.01	0.0251
Oxygen	44.036	15.49	0.0688
Proximate Analysis (wet basis)			
	Value (wt. %)	**Value (wt. %)**	**Value (wt. %)**
Moisture	25	3.7	0.1112
Fixed Carbon	12.56	64.9	0.4419
Volatile Matter	81.9	27.1	0.3499
Ash	1.68	4.3	0.097

Techno-Economic Analysis

The techno-economic analysis evaluates a preliminary design for the production and co-firing of bio-oil heavy ends with coal in a combined heat and power facility. This analysis requires estimates of the capital and operating costs in order to determine the minimum electricity-selling price (MESP). These estimates depend on some general assumptions regarding the facility operation and its costs.

In this study, the base case scenario assumes that the facility is an n^{th} plant design with major technological breakthroughs accomplished, and with no major technical, or operational challenges. The facility requires a construction time of less than 24 months. During its startup period of 6 months, the facility achieves 50% of its operating capacity but spends 75% of variable expenses and 100% of fixed expenses. The facility availability is 90% or about 7900 hours of the year, which allows time for scheduled maintenance and unexpected downtime.

Capital Costs

This study employs Aspen Process Economic Analyzer™ (APEA) to estimate equipment-purchasing costs based on the mass and energy balances determined by Aspen Plus™. Each unit operation in the Aspen Plus™ model is mapped into a defined APEA cost unit. APEA uses established industry conventions and a proprietary database to determine equipment configurations, materials of construction, and size among other engineering parameters. Finally, the capital cost estimate employs Peters and Timmerhaus factors to calculate the installed equipment cost and total project investment [ref] as shown in Table 1. This procedure only accounts for the equipment cost of major operating units, and it should be considered a preliminary design with an accuracy of -30/+100%.

Table 4 Cost factors for estimating total project investment costs based on the total purchased equipment cost

Total Purchased Equipment Cost (TPEC)	100%
Purchased Equipment Installation	39%
Instrumentation and Controls	26%
Piping	31%

Electrical Systems	10%
Buildings (including services)	29%
Yard Improvements	12%
Service Facilities	55%
Total Installed Cost (TIC)	3.02
Indirect Costs	
Engineering	32%
Construction	34%
Legal and Contractors Fees	23%
Total Indirect	3.91
Project Contingency	78.2%
(Working Capital shown in DCFROR)	
Total Fixed Capital Investment	4.69
Non-depreciated Direct Costs	
Land	6.00%
Total Investment (with Land)	
Lang Factor	**4.75**

The chemical process model does not include auxiliary equipment necessary for the operation of the facility. These auxiliary units consist primarily of material handling equipment (forklifts, conveyors, etc.). Due to their importance in solid handling facilities, this study relies on data provided by the National Renewable Energy Laboratory (NREL) to estimate their costs based on a similarly sized solid handling facility.

Operating Costs

The primary operating costs for this facility include material, labor, capital, land, overhead, and maintenance. Material costs consist of corn stover and coal purchased for bioproduct and power generation, and the byproducts biochar, bio-oil light ends, and process steam sold at their estimated market value. This study assumes market prices of \$83 and \$57.3 per Mg for corn stover and coal respectively. Biochar and bio-oil light ends are projected to have values of \$22.1 and \$21.75 per Mg based on their agronomic and chemical content value respectively. Market prices for high, medium, and low pressure steams are assumed to be \$7.94, \$6.62, and \$5.29 per Mg based on Peters and Timmerhaus.

Labor costs are based on salary values provided by NREL and adjusted to account for the two separate facilities. Table 2 shows the employee position, salary, and total number employed for the fast pyrolysis and CHP facilities.

Table 5 Employee salaries and number for the combined fast pyrolysis and CHP facilities

Position	Salary	Number
Plant Manager	\$80000	2
Plant Engineer	\$65000	2
Maintenance Supervisor	\$60000	2
Lab Manager	\$50000	2
Shift Supervisor	\$37000	10
Lab Technician	\$25000	3
Maintenance Technician	\$28000	16
Shift Operators	\$25000	40
Yard Employees	\$20000	64
General Manager	\$100000	1
Clerks & Secretaries	\$20000	5

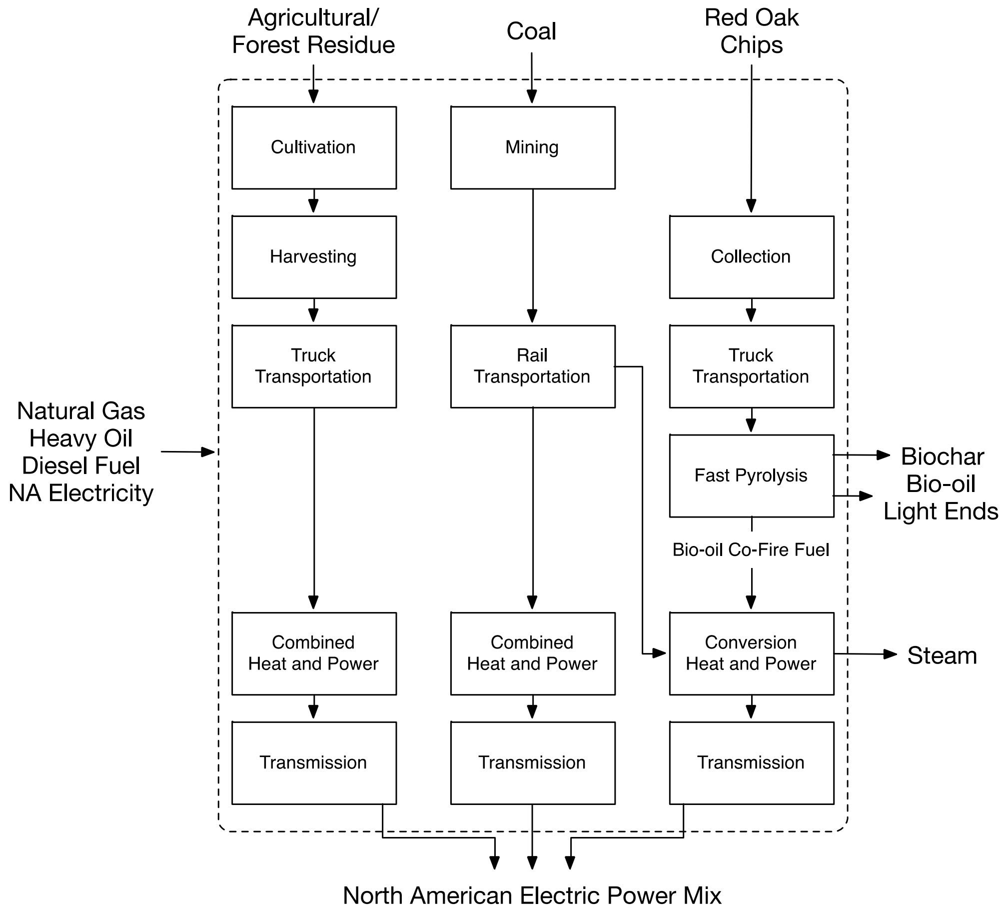
The equivalent annualized cost of capital is based on a 20-year discounted cash flow rate of return (DCFROR) analysis. In the DCFROR, the cost of capital includes equipment depreciation, loan, tax, and return on investment (ROI) costs.

Equipment depreciation costs are estimated based on a 7-year modified accelerated cost recovery system (MACRS), which employs both double-declining and straight-line depreciation methods to maximize the economic return. We assume a negligible salvage value for the facilities. Loan interest rates are assumed to be 7.5% with a 10-year term, but we assume the facility is financed by 100% equity. The income tax rate is 39%, and the internal rate of return is 10%.

Life Cycle Analysis

The life cycle analysis (LCA) employed the latest version of Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET v2013) to estimate the well-to-plant (WTP) emissions of various scenarios. The base case scenario consists of electricity generation via bio-oil co-firing fuel (BCF) with coal in a combined heat and power (CHP) plant. This scenario was later compared to biomass- and coal- only options for power generation.

The system boundaries for the LCA include various processes shown in [Fig.]. These processes consist of feedstock collection, transportation, conversion, and transmission of electricity. For biomass power, upstream processes include feedstock cultivation and harvesting; coal pathways include coal mining and collection steps. The output products considered are electricity, biochar (sequestered), and aqueous phase bio-oil.



Greenhouse Gas Inventory Data

The following table lists greenhouse gas inventory data for the primary materials and technologies employed in the LCA. The base case scenario employs red oak as the primary renewable energy input, which is modeled based on forest residue GREET data and the compositional data described above. Coal GHG data is based on the North American mix… Other important inputs include natural gas, diesel fuel, and electricity. GREET includes assumptions for the output materials electricity and biochar. The carbon and sulfur ratios for red oak and biochar were modified to fit the experimental data available.

Life Cycle Emissions	Red Oak Chips	Forest Residue	Coal	Corn Stover
VOC	1.405 g	1.693 g	7.630 g	4.860 g
CO	6.605 g	7.469 g	2.589 g	9.430 g

NOx	13.215 g	15.779 g	12.769 g	24.389 g
PM10	1.233 g	1.430 g	173.730 g	2.446 g
PM2.5	1.047 g	1.182 g	43.348 g	1.634 g
SOx	776.305 mg	1.339 g	7.171 g	12.672 g
CH4	3.266 g	5.555 g	148.348 g	17.703 g
N2O	32.432 mg	67.311 mg	30.811 mg	6.649 g
CO2	2.144 kg	3.648 kg	1.592 kg	5.007 kg
CO2 Biogenic	-707.141 mg	-1.200 g	-3.808 g	-6.503 g
CO2 Land Use Change	0.000 g	0.000 g	0.000 g	0.000 g
CO2 Fertilizer	0.000 g	0.000 g	0.000 g	0.000 g
Groups				
Greenhouse Gas	90.612 g	157.740 g	3.714 kg	2.418 kg

LCA Methodology

The LCA methodology employs GREET to estimate the well-to-pump (WTP) emissions for the proposed system. Figure 2 shows the overall diagram as captured from the GREET modeling software. There are 5 distinct steps modeled, which are corn stover collection, transportation, pyrolysis, coal co-firing, and electricity transmission and distribution. Each of these steps involve the use of energy and the generation of greenhouse gas emissions.

Corn stover collection consumes energy primarily in the form of diesel for non-road engines, and nitrogen, phosphoric acid, and potassium oxide that are removed with the material. The corn stover is then transported in stacks by a heavy-duty truck a distance of 38 miles to the pyrolysis facility.

The pyrolysis facility consumes corn stover, and small amounts of electricity and natural gas. The electricity consists of the U.S. average power generation mixture. The co-products of the pyrolysis facility are biochar and bio-oil light ends. Due to the difficult in comparing these to market equivalent products, this analysis uses a mass allocation method to distribute on-site emissions among the various pyrolysis products. Furthermore, we assume that biochar soil application behaves as a low-energy carbon sequestration agent.

Argonne National Lab recently conducted a detailed study of biochar sequestration strategies [ref].

The bio-oil co-fire fuel and coal are fed into a utility boiler combined heat and power system. Coal delivery is modeled as the coal for power plant single pathway, which incorporates the average LCA impact of U.S. coal delivered to power plants. The mass input ratio is 70/30 coal to biomass, which corresponds to 86.6/14.4 on an energy basis. The combined thermal efficiency of converting coal and BCF to electricity is 26.8%. Approximately 16% of on-site emissions are considered to be urban emissions.

The final step in the LCA system is the electric transmission and distribution to the U.S. grid. The assumed efficiency for electricity transmission is 93.5%.

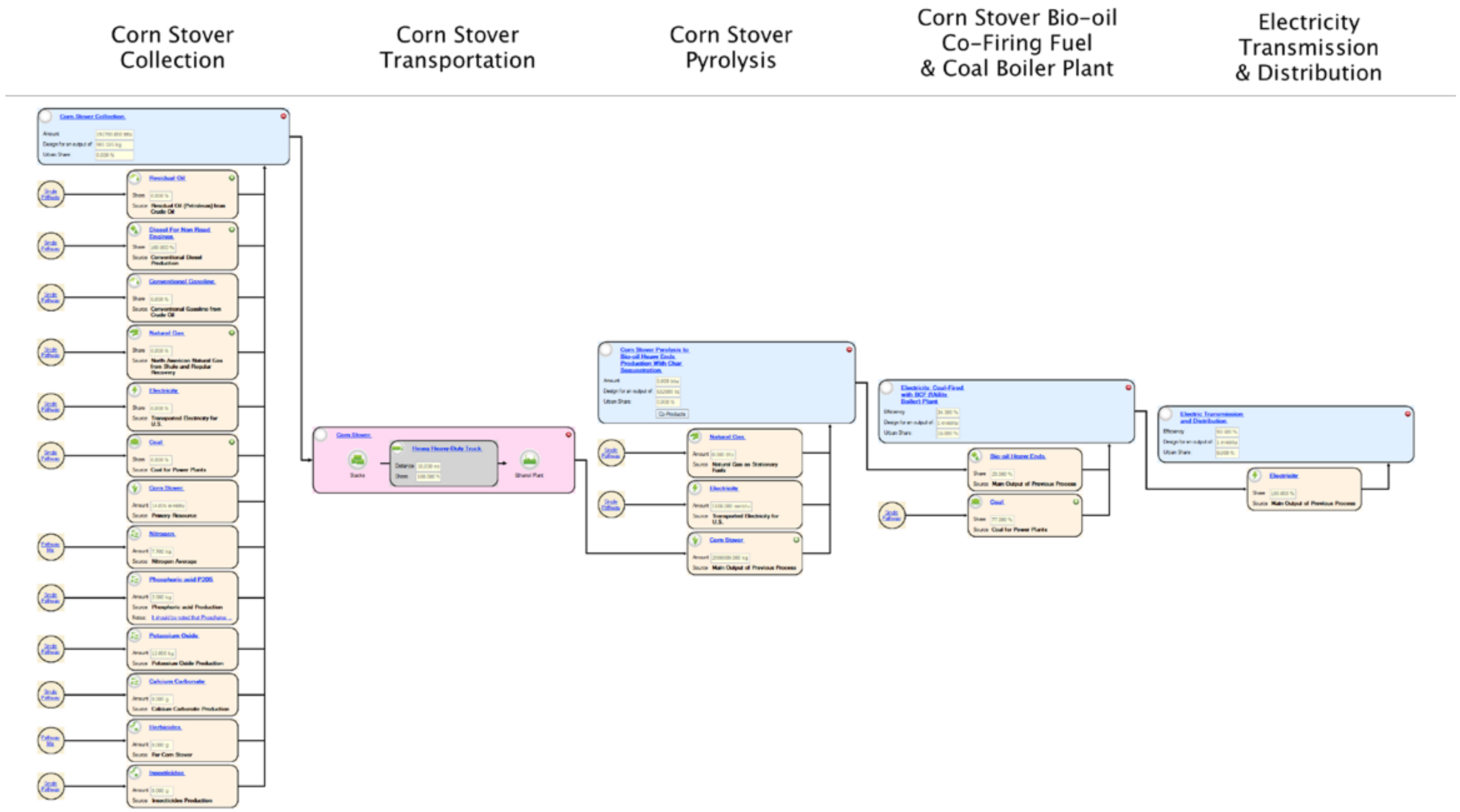


Figure 2 Corn stover fast pyrolysis and coal-bio-oil co-fire fuel combined heat and power production well-to-pump diagram

Incentive Value Analysis

At the onset of this project, there were indications that the EPA would consider Renewable Identification Numbers (RINs) for the use of renewable biomass in power production particularly for end use in battery-powered electric vehicles (BEV). RIN values have proven useful in incentivizing the production of renewable fuels for the transportation market. However, current guidance is that the EPA will not accept RIN values for power generation. Nonetheless, there are other potential incentive avenues to consider for this project.

Several coal power facilities have struggled to meet new regulations that require strict caps in the emissions of power generating facilities. While this has been widely considered an opportunity for growing the use of carbon capture and sequestration (CCS) technology, CCS suffers from high capital and parasitic energy costs. The lack of viable alternatives has already led to lower power contributions from coal facilities at the expense of natural gas which achieves lower emissions and higher overall efficiencies. The BCF concept could revitalize closed coal power facilities by providing a lower cost option than CCS for reducing coal power emissions. However, a detailed analysis comparing the cost of BCF to CCS has yet to be done.

Another potential incentive would be the development of a carbon trade market. By virtue of the carbon negative nature of BCF, a carbon trade market could be an important revenue source for a facility utilizing the BCF model. In this study we provide a simple calculation of the required carbon market price to make this system viable.

Results

Techno-Economic Analysis

The process model results indicate that the fast pyrolysis facility converts 2000 Mg per day of corn stover into 632 Mg of bio-oil co-fire fuel (BCF), 895 Mg of light ends, and 158 Mg of biochar with the balance consisting of flue gas and ash. The BCF is subsequently mixed with 1467 Mg of bituminous coal at a 70/30 BCF to coal ratio. A steam boiler, operating at 1100 °C, raises high-pressure (28 bar) steam by combusting the fuel mixture. An economizer employs excess heat from the boiler to preheat process water for steam generation. Combustion gases flow through a series of heat exchanger raising high-, medium- (11 bar), and low- (2 bar) pressure steam. Steam turbines expand a majority of the steam to produce electric power. In summary, 121, 40, and 15843 Mg per day of high-, medium-, and low-pressure steam are generated, and 82.9 MWe is exported as summarized in Table 3. Figure 1 shows a simplified process flow diagram of the corn stover fast pyrolysis and BCF-Coal combined heat and power system.

Table 6 Corn stover fast pyrolysis and BCF-Coal power production key material flows

Material	Tonnes per day	Price ($/MT)	Energy Content (HHV - MJ/kg)
Corn Stover	2000	83	18.0
Coal	1467	57.3	29.5
Biochar	158	-22.1	13.83
Light Ends	895	-21.75	4.28
Steam (2 bar)	15843	-5.29	
Steam (11 bar)	40	-6.62	
Steam (28 bar)	121	-7.94	

Figure 2 describes the overall energy outputs as fractions of the coal and corn stover inputs to the fast pyrolysis and combined heat and power systems. As shown, a majority of the input energy becomes steam at various pressure levels. The LP steam contribution is small because of the amount of heat sent to the economizer. The process was designed for high electricity production relative to high-pressure steam generation on the basis that most of the steam will be for residential uses (hot water). Fast pyrolysis products contain a small fraction of the overall energy in part because of the high energy input of coal to the CHP system. Furthermore, a significant portion of the biochar is consumed in the HRSG system (about 1/3). Most of the energy losses occur in the HRSG and CHP boilers, and other energy losses include sensible heat in flue gas streams, and stranded heat in miscellaneous process units.

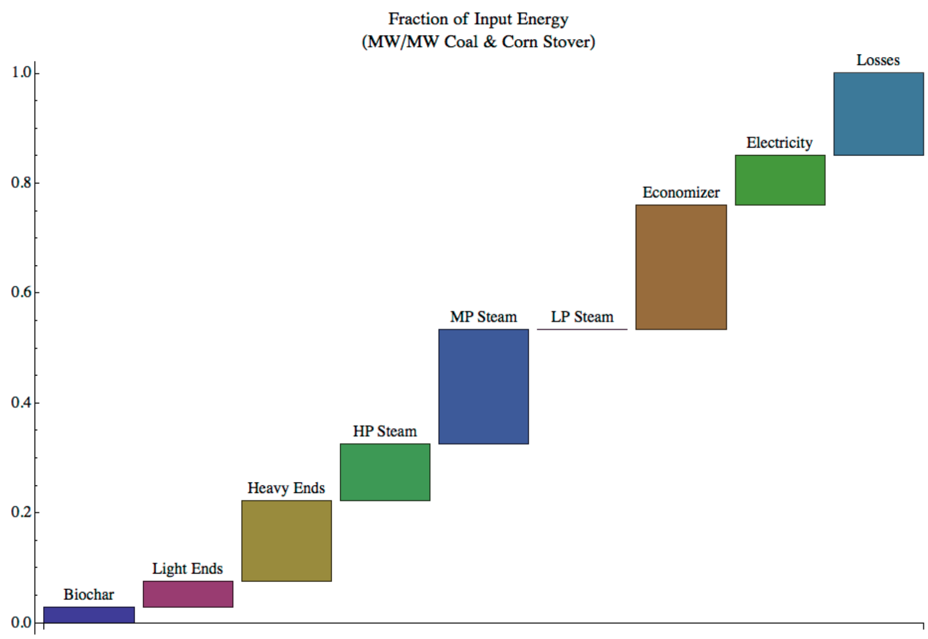


Figure 3 Energy balance of the corn stover fast pyrolysis and BCF-Coal combined heat and power system

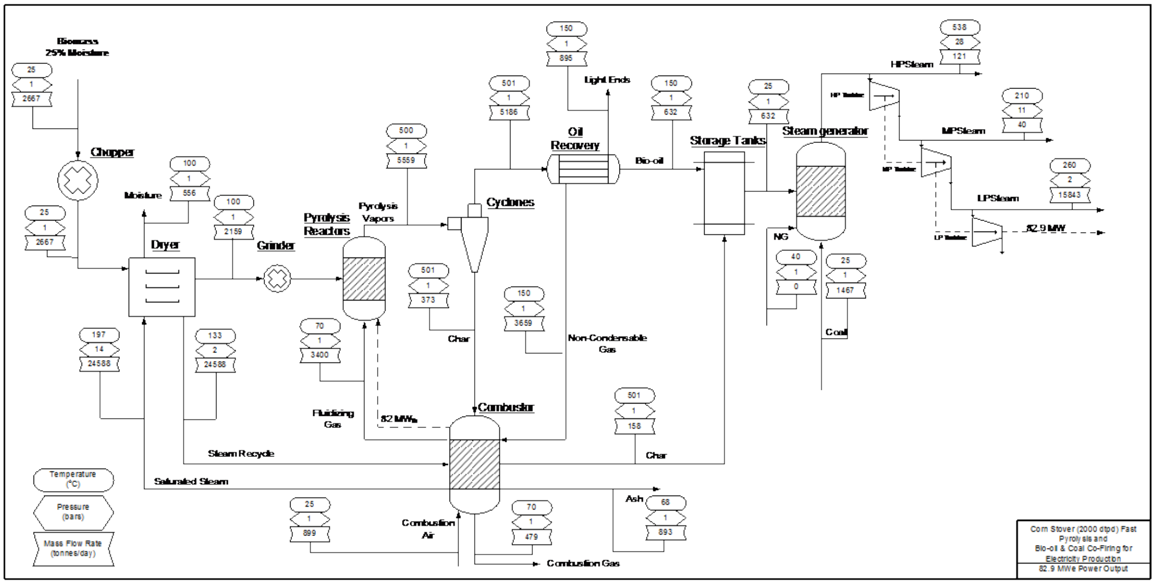


Figure 4 Simplified process flow diagram of corn stover fast pyrolysis and combined steam and power production from bio-oil co-fire fuel and coal

The equipment cost estimate includes over 100 major processing units with a total purchased cost of $45.5 MM. The total project investment cost is $216 MM. The fixed capital cost represents a $2574/kW of capacity investment, which compares to $1200/kW for a turnkey installation based on EPA estimates. The total fixed capital cost are grouped by process area and summarized in Figure 2. The combined heat and power (CHP) process has the highest capital cost contribution at 35.0% followed by pretreatment (32.2%) and heat recovery steam generation (HRSG) at 21.5%. Product storage costs are small and only account for the small quantity of biochar and light ends generated.

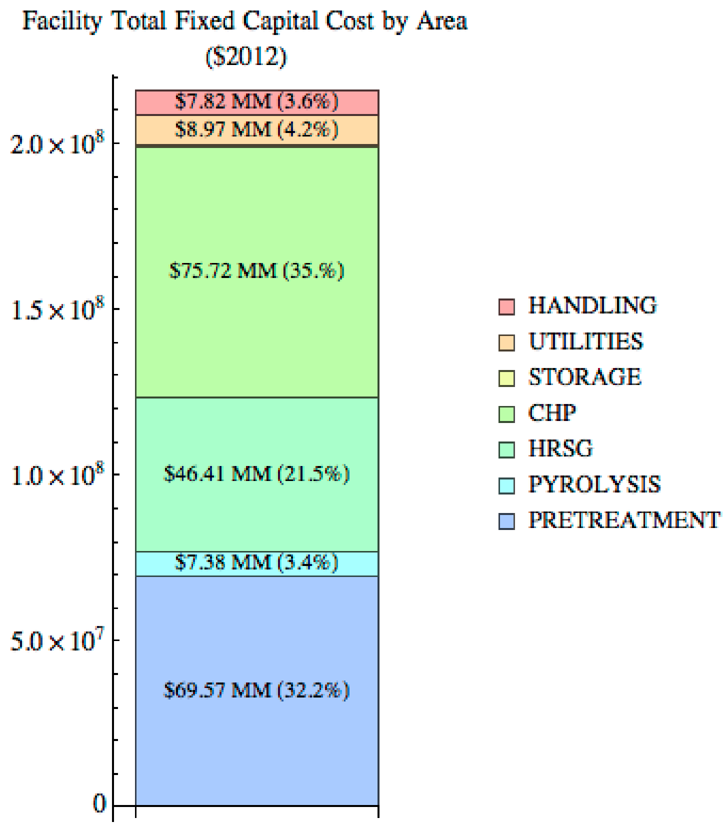


Figure 5 Corn stover fast pyrolysis and BCF-Coal power production fixed capital costs by process area

Corn stover contributes the majority of the total operating cost with an adjusted value of 60%. Coal costs come second with a 30.4% contribution. Coal costs are almost completely offset by the sale of low-pressure steam, which generates $27.59 MM per year compared to the $27.67 MM coal cost per year. Bio-oil light ends and biochar generate revenues of about 7.5% the total operating cost. Figure 3 shows all the major operating costs by category.

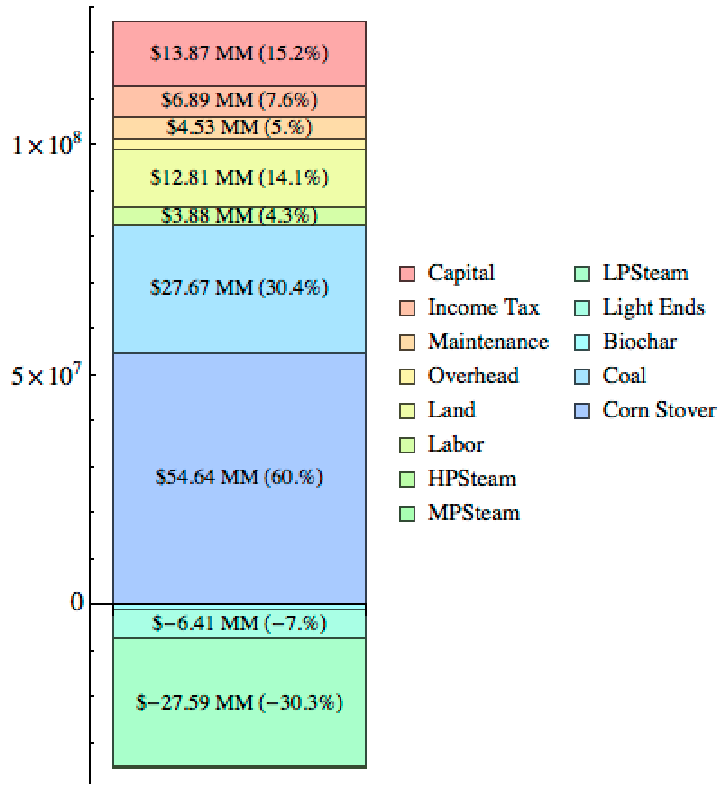


Figure 6 Corn stover fast pyrolysis and BCF-Coal power production operating costs

In order to achieve a 10% internal rate of return, this facility would need to sell electricity at a cost of 15.2 cents per kWhr. This estimate compares to an average 2013 electricity price of 9.74 cents per kWhr for all sectors in the U.S. The highest electricity prices are for the residential sector where it cost 12.03 cents per kWhr in 2013. Figure 4 compares this project's electricity cost estimate to those of different U.S. sectors.

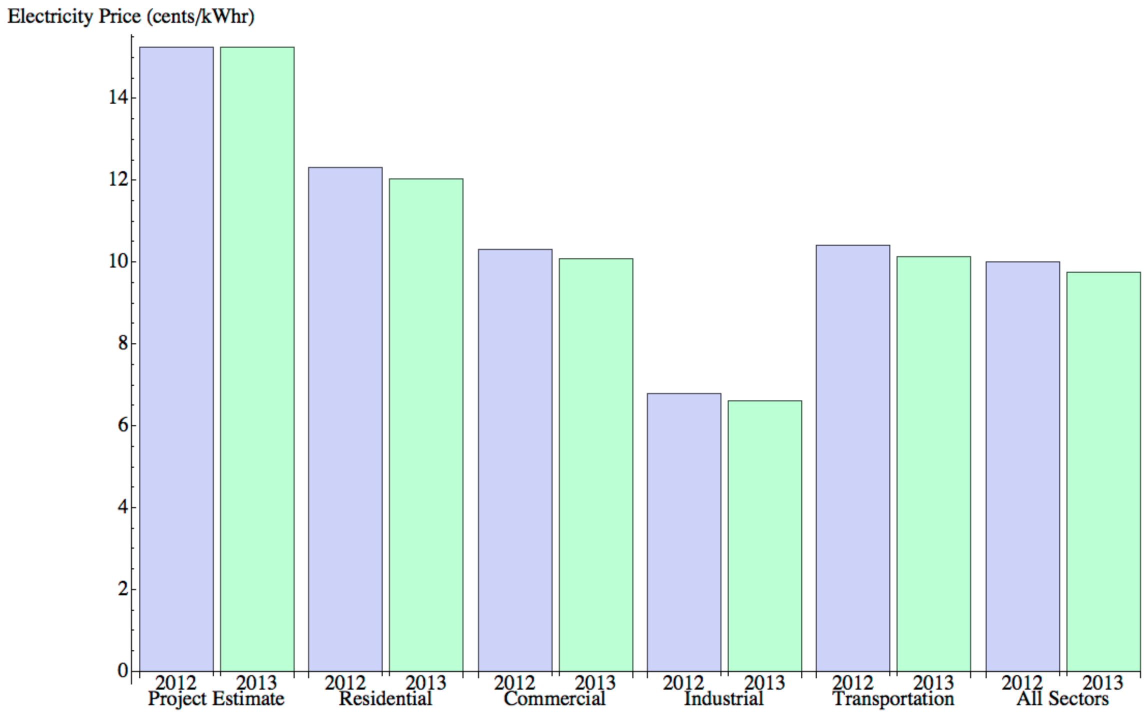


Figure 7 Electricity price comparison for various U.S. sectors (Source: EIA http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a)

These results indicate a higher than market price cost of using BCF and coal to generate electricity. However, the difference of 5 cents per kWhr could be overcome depending on numerous factors. For example, lower feedstock cost, higher byproduct revenue, and improved overall efficiency are potential avenues to lower these production costs. On the other hand, the uncertainty of the capital cost estimate and the current state of technology suggest that more research is needed to better understand the commercialization potential of this technology.

Life Cycle Assessment

The results of the LCA are summarized in Table 7 and compared to other pathways for electricity production using biomass or coal in utility boilers. The proposed pathway in this study achieves a net greenhouse gas reduction of 13.124 kg of CO_2 equivalent per million btu (mmbtu) of power generated. This reduction in GHG emissions is much less than using forest residue alone (656.3 kg CO_{2e}/mmbtu) but is a significant improvement compared to net emissions of 13.1 kg CO_{2e}/mmbtu for coal power generation. Furthermore, we expect much lower NOx and SOx emissions by virtue of the lower Nitrogen and Sulfur contents in biomass. An important note is the lack of land use change and fertilizer emissions due to the use of non-food crops and absence of fertilizer use (the corn stover scenario allocates fertilizer use to corn production).

Table 7 Life cycle well-to-pump greenhouse gas emissions of several utility boiler power production pathways per mmbtu of electricity generated.

	Farmed Trees	Forest Residue	Herbaceous	Coal	Coal + Corn Stover
VOC	34.985 g	48.197 g	46.326 g	27.821 g	36.577 g
CO	424.022 g	1.410 kg	425.720 g	42.255 g	48.736 g
NOx	627.843 g	652.859 g	644.204 g	473.486 g	129.252 g
PM10	71.934 g	782.189 g	71.685 g	585.715 g	623.757 g
PM2.5	37.541 g	706.941 g	36.915 g	171.431 g	158.996 g
SOx	11.071 g	6.883 g	12.603 g	1.256 kg	80.250 g
CH4	43.789 g	188.736 g	84.463 g	463.367 g	568.287 g
N2O	61.646 g	22.601 g	111.327 g	5.236 g	14.206 g
CO2	12.633 kg	683.743 kg	14.764 kg	315.238 kg	33.876 kg
CO2Biogenic	-526.018 kg	-667.712 kg	-492.411 kg	-11.804 g	-31.565 kg
CO2LandUseChange	0.000 g	0.000 g	0.000 g	0.000 g	0.000 g
CO2Fertilizer	0.000 g	0.000 g	0.000 g	0.000 g	0.000 g
Greenhouse Gas	**-506.553 kg**	**-656.259 kg**	**-457.124 kg**	**13.133 kg**	**-13.124 kg**

Incentive Value Analysis

This study estimates the required minimum carbon price to support the proposed BCF system when compared to conventional coal power generation technology. At an estimated cost of 15.2 cents/kWhr, the BCF concept is 5.46 cents/kWhr more expensive than the average electricity price in the U.S. However, its emissions are 26.26 kg of CO_{2e} less than conventional coal power production. BCF would be cost-competitive with coal power production at a carbon market price of $2.079/Mg of CO_{2e}.

This carbon market price has already been seen in established carbon markets around the world. This result suggests that BCF could be one of the initial avenues to utilizing biomass as a carbon emission reduction agent. A detailed cost analysis that compares the BCF approach to conventional biomass-coal co-firing technology would indicate the most likely scenario at low carbon market prices.

Discussion