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Techno-Economic Assessment of Co-Hydrothermal Carbonization of a Coal-Miscanthus Blend

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Abstract: Co-Hydrothermal Carbonization (Co-HTC) is a thermochemical process, where coal and biomass were treated simultaneously in subcritical water, resulting in bulk-homogenous hydrochar that is carbon-rich and a hydrophobic solid fuel with combustion characteristics like coal. In this study, technoeconomic analysis of Co-HTC was performed for a scaled-up Co-HTC plant that produces fuel for 110 MWe coal-fired power plant using Clarion coal #4a and miscanthus as starting feedstocks. With precise mass and energy balance of the Co-HTC process, sizing of individual equipment was conducted based on various systems equations. Cost of electricity was calculated from estimated capital, manufacturing, and operating and maintenance costs. The breakeven selling price of Co-HTC hydrochar was $117 per ton for a 110 MWe. Sensitivity analysis indicates that this breakeven selling price could be as low as $106 per ton for a higher capacity plant. Besides plant size, the price of solid fuel is sensitive to the feedstock costs and hydrochar yield.

Keywords: coal; biomass; hydrochar; process economics; sensitivity analysis; cost of electricity

1. Introduction

Coal dependence has led to significant air pollution as the combustion of coal releases various air pollutants (trace metals, chlorine, greenhouse gases etc.) that are hazardous and toxic to the surrounding life and environment. In 2016, U.S. coal combustion accounted for 26.3% of the CO_2 produced from fossil fuel combustion and contributed to nearly 69% (CO_2 equivalent basis) of the greenhouse gases produced from the electrical power generation sector [1]. In the same year, the electrical power sector also contributed to 43.8% of the total SO_2 released, of which 92% was contributed by coal combustion [1]. The mitigation of these pollutants while meeting the electricity demand are essential for keeping up with the continual growth of the world's economy as well as maintaining its environmental health. In the U.S., nearly 261 billion tons of coal are available in recoverable coal reserves (as of 2012) which is estimated to last for more than 150 years based on an average production rate of 1.5 billion tons per year [2]. Such resource availability allows for U.S. coal-fired power plants account for approximately 40% of yearly electricity generation (per 2015) while 2040 projections expect total consumption to be 705 million short tons (an approximate energy equivalent of 13.49 quadrillion) [3].

In 2017, biomass was the highest primary energy producer among renewable energies at 45.6% while accounting for 5.8% of the U.S. total primary energy produced (fossil fuels, nuclear, and renewables) [4,5]. Biomass utilization as a fuel can minimize greenhouse gas emission as the emitted carbon dioxide was originally used for plant growth via photosynthesis [4]. Thus, in an attempt to reduce coal-fired plant emissions in the form of toxic metals, sulfur dioxide, and nitrogen oxides, co-firing of biomass and coal has been implemented [6,7]. Despite the reduced environmental impacts from co-firing, significant combustion setbacks are still experienced. Overall energy content is reduced due to co-combustion of higher heating value of coal (e.g., 24–30 MJ kg^{-1}) with lower heating value of biomass (10–22 MJ kg^{-1}) [8–13]. Additionally, coal densities (e.g., 700–900 kg m^{-3} for bituminous coals) vary with biomass densities (e.g., 100–600 kg m^{-3}) which can result in density partioning and overall lack of homogeneity in the coal-biomass mixture [8–13]. Lastly, biomass processing (e.g., milling, drying, etc.) prior to co-firing are necessary installments that can be costly due high moisture content. In fact, a 2004 EERE study discussed that minor boiler modifications could be performed for existing coal plants in order to co-combust with biomass, however, feedstock handling for drying, grinding, and overall homogeneity would have to be maintained [14].

Hydrothermal carbonization (HTC) has been extensively researched for biomass pretreatment and low rank coal dewatering [15–19]. HTC uses subcritical water (temperatures 180–260 °C) to convert biomass into a carbon-rich and hydrophobic solid fuel, known as hydrochar. Co-Hydrothermal Carbonization (Co-HTC) is the simultaneous treatment of two feedstocks in the presence of subcritical water. Co-HTC can promote the synergistic interaction between the two feedstocks during treatment, which would not occur when the feedstocks are separately treated (i.e., HTC). Shen et al., demonstrated de-chlorination could be improved with Co-HTC [20]; as biomass intermediates produced during treatment provided more phenolic compounds and short chain organic intermediates to react with chlorine groups in PVC. Zhang et al., showed increased organic and carbon retention rates for the Co-HTC of sewage sludge and pine sawdust as opposed to the individual HTC of each respective feedstock [21]. It was hypothesized that Mailard reactions between sawdust sugar derivatives and sewage sludge protein formed insoluble hydrochar. More applicable to improved co-firing, Nonaka et al., and Saba et al., evaluated the Co-HTC of biomass-coal blends with varying feedstock compositions and varying reaction temperature, respectively. Nonaka et al., found that Co-HTC favored more polymerization reactions and that more thermally stable hydrochars were produced from higher coal ratios [22]. Furthermore, heating value and chemical characterization did not change notably with changing feedstock compositions. Meanwhile, Saba et al., observed hydrochar homogeneity and additional biomass degradation (via mass yield) catalyzed by Co-HTC with coal, resulting in lower pH media [23]; low pH would then encourage more leaching of inorganic content and sulfur. As expected, both studies found increased HHV of produced hydrochars than that of the blended and untreated feedstocks. Overall, hydrochar can potentially serve as a better option for co-firing than biomass; co-treatment with coal can have significant advantages as well.

HTC energetics have shown to be promising as the heat of reaction was shown to be exothermic by Funke and Ziegler [24]. For HTC of glucose, cellulose, and wood at 240 °C and 6 h heats of reactions were determined via digital scanning calorimetry to be approximately −1 MJ kg^{-1} for each feedstock. Increasing reaction severity through temperature (>310 °C) and time (64 h) resulted in a minimum heat of reaction of −2.4 MJ kg^{-1} as a result of the production of lower energy products CO_2 and H_2O [24]. Although consideration for reaction by-products were considered, all carbon losses from experimental mass balance was assumed to have gone into the gas phase as CO_2. These results show potential for alleviating energy input for a continuous process. In fact, utilization of these results allowed McGaughy et al., to perform an energy audit on a simplified continuous HTC plant that treats food waste [25]. Energy output to input ratio (EOIR) were 2.95–4.91 depending on HTC reaction temperature.

Although HTC treatment shows promising fuel upgrading and energy savings from decreasing energy duty for the feedstock drying step, process economics should also be considered for feasibility. Li et al., performed a techno-economic models for rice husk to fuel conversions via HTC, pyrolysis, and anaerobic digestion and compared them to the direct combustion of rice husks for heat and power [26]. With considering operating costs and negligible differences in fixed capital costs, HTC of rice husks proved to be a more advantageous process compared to the other two as it can have higher solids loading, lower utilities costs, and lower process water costs. For 1-ton rice husk conversion, HTC cost per MJ was \$0.013 MJ^{-1} (\$153 MWh^{-1}), having 81% and 38% savings compared to fossil fuel oil costs and direct combustion of rice husks (when not incorporating capital costs into the HTC costs), respectively. This cost is still 4.5 times more than the cost of Central Appalachian Coal at \$33.7 MWh^{-1} [27]. Further heat integration of HTC process liquid can further benefit the process economics in this study with more temperature optimization of HTC. Additionally, considering capital costs, maintenance costs, and the time value of money contributes to a more accurate model for commercial design.

Lucian et al., did process modeling for the HTC of grape marc and off-specification compost from raw processing to pelletized hydrochar [28]. Of the various process parameters, process optimization from their data occurred at the shortest residence time of 1 h (from 1, 3, and 8 h times), a reaction temperature of 220 °C, and a slightly higher dry biomass-to-water treatment ratio of 0.19. Treatment at 220 °C from 180, 220, and 250 °C produced a high enough higher heating value (HHV) without excess energy input, which allowed for enough heat integration and lowered hydrochar drying costs as samples were more hydrophobic and had lower mass yields. Most electrical costs came from pelletization and reactor feed pumping, while most thermal costs came from HTC reaction heating. HTC reaction heating input was significantly larger for lower dry biomass-to-water ratio as there is less energy efficiency from heating more water content, which is why the higher ratio of 0.19 yielded better optimization. Overall pellet production cost was \$171.1 per ton of hydrochar and overall breakeven cost was equal to \$218 per ton; these costs were considered competitive with the cost of wood pellets (\$163.5–218 per ton) but not with coal costs. Co-treatment can remove pelletization costs as coal is not pelletized for traditional coal firing and heat integration is essential for viability. Shorter retention times have shown to be effective for hydrochar conversion and can increase revenue by allowing more product to be produced. To the author's knowledge, process economics have not been performed for a Co-HTC system, regardless of the feedstocks treated. Therefore, the main objective of this study is to evaluate techno-economic viability of Co-HTC of bituminous coal with miscanthus, while taking into consideration of capital costs and overall operating and maintenance costs over the plant lifetime. Heat integration will also be taken into consideration to reduce energy costs and to improve overall plant design.

2. Materials and Methodology

2.1. Co-Hydrothermal Carbonization Experiments

Detailed descriptions of the HTC and Co-HTC materials and methodologies for batch experiments can be found in a previous publication by Saba et al., [23]. *Miscanthus* (Miscanthus × giganteus) and Clarion Coal #4a (bituminous) were used for base case hydrothermal upgrading as well as Co-HTC. Base case HTC experiments consisted of loading a Parr stirred-batch reactor at 1:10 solids-to-DI water ratio, heating the contents to 230 °C, holding the reaction temperature isothermally for 30 min, and then cooling the contents down to room temperature with an ice-bath. Average heating time was 20 min to reach 5 °C below target temperature, and cooling times were less than 5 min to reach 80 °C. Same process was performed for Co-HTC runs, where a 1:1 miscanthus-to coal-mixing ratio was used. All products were dried in an oven at 105 °C for 24 h. Physio-chemical properties of hydrochars produced from HTC and Co-HTC experiments are shown in Table 1.

Table 1. Carbon, sulfur, and ash content of untreated feedstocks and hydrochars on a dry-basis.

Feedstock	Mass Yield (%)	HHV ($MJ \cdot kg^{-1}$)	Carbon (%)	Hydrogen (%)	Nitrogen (%)	Oxygen * (%)	Sulfur (%)	Ash (%)
Coal-untreated	-	27.4 ± 0.0	63.8 ± 1.2	4.1 ± 0.1	1.5 ± 0.1	26.0 ± 0.5	4.6 ± 0.8	11.1 ± 0.6
Miscanthus-untreated	-	19.7 ± 0.2	48.7 ± 0.1	5.7 ± 0.1	<0.5	45.4 ± 0.1	<0.5	1.3 ± 0.1
Coal 230 °C	99.2 ± 1.2	29 ± 1.0	69.2 ± 1.6	4.6 ± 0.3	1.7 ± 0.1	20.8 ± 1.9	3.8 ± 0.1	9.5 ± 1.1
Miscanthus 230 °C	57.2 ± 0.3	24.6 ± 0.4	59.3 ± 1.5	5.4 ± 0.1	<0.5	35.0 ± 1.5	<0.5	<0.5
Blend 230 °C	66.9 ± 0.8	26.1 ± 0.6	67.2 ± 2.0	4.2 ± 0.2	1.1 ± 0.1	25.6 ± 1.8	2.0 ± 0.3	5.3 ± 2.3

(* calculated by difference by source) [23].

2.2. Co-Hydrothermal Carbonization Process Overview

A process flow diagram (PFD) representing the Co-HTC system that treats miscanthus and coal is shown in Figure 1. This treatment includes filtering and drying the solid product that would be sold to coal fired power plants. In this process, miscanthus and coal are mixed, pressurized, and sent into a preheater/heat exchanger. Increasing the pressure prior to the pre-heater is necessary to avoid vaporization of the water. The slurry is pumped again to an outlet pressure of 34.5 bar (500 PSIG) for reactor operation and major and minor losses that are bound to occur in the system. Next, the slurry is sent into the reactor, which operates at 230 °C and 28.2 bar (410 PSIG) and is treated for a residence time of 5 min. All the heat exchangers and pumps are assumed to operate at an 80% efficiency in this model. After the residence time, the upgraded Co-HTC solid product, carbon dioxide gas, and process liquids are sent through the preheater to recover heat. Excess pressure is utilized to drive the product stream through a leaf filter; the hydrochar then is assumed to have a 20% moisture content after filtration [29]. From here, the solid product is sent to dry, where moisture content is brought down to 11%. This is well within the typical range of moisture content used for coal feeds at pulverized coal power plants [27]. The solid Co-HTC hydrochar is now ready to be utilized at the power plant. The gas is vented into the atmosphere and process liquid is sent to a wastewater treatment plant. Miscanthus feedstock and dried hydrochar will be stored onsite in separate storage tanks.

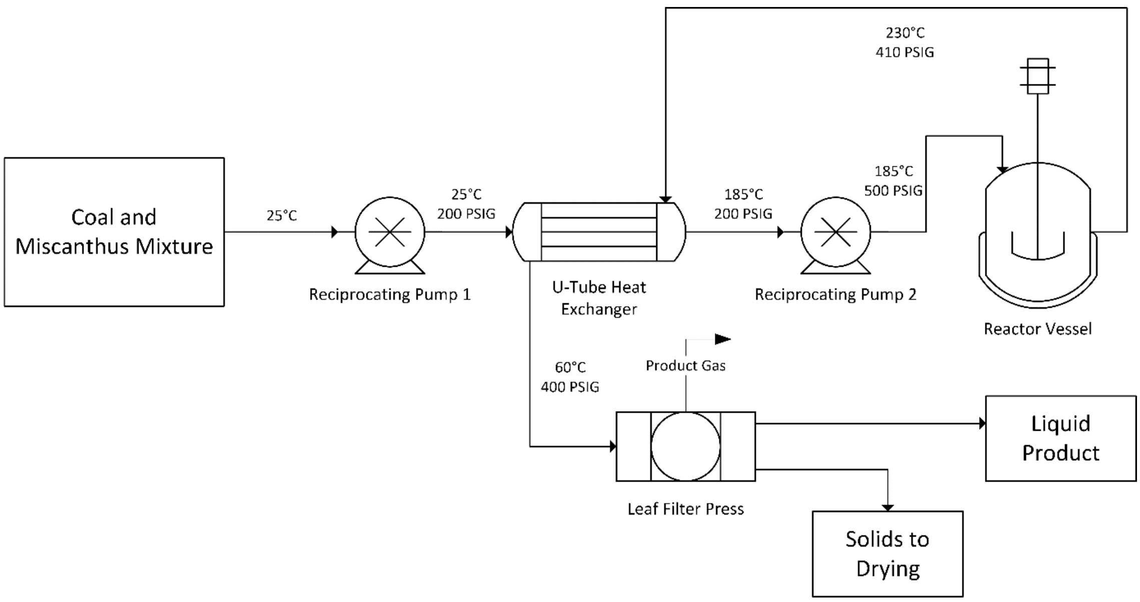

Figure 1. Simplified process flow diagram of Co-Hydrothermal Carbonization (Co-HTC) treatment used for economic analysis.

2.3. Co-HTC Process Economics

The methodology described below in this subsection is used for economic analysis. An economic analysis was performed for a scaled-up Co-HTC process to provide solid fuel for power plant combustion, such as an existing pulverized coal power plant. Capital cost estimations followed study estimates and preliminary design estimates, summarized by Turton et al., which were approximate parallels to estimate Class 2 and Class 3 in the Association for the Advancement of Cost Engineering Cost Classification System recommended practices report [30,31]. Following Turton et al., methodology, capital is estimated to fall between a −25%/+40% accuracy range. All prices shown have been adjusted to a 2016 USD standard (CEPCI = 541.7) unless otherwise noted; all prices in $/ton are in dry ton of fuel.

Data obtained from previous batch studies and analyses performed for Co-HTC hydrochars, produced at 230 °C, were applied towards mass and energy balances in order to determine energy outputs, unit operation electrical requirements, and product produced for combustion. Energy demands/outputs, electrical demands, and flow rates were then be used to determine investments costs (capital, sizing, etc.) and cash flows.

Investment cost and cash flows are used to determine net present value (NPV) of the plant via Equation (1) [30].

$$\mathrm{NPV} = \mathrm{TCI} + \sum_{k-1}^{n} F_k \cdot (1+i)^{-k} \tag{1}$$

where TCI is total capital investment, F_k is the annual after-tax cash flow, i is the interest rate, k is the year being evaluated using a year zero baseline, and n is the total number of years the plant is operating. NPV is used to find the product selling price for the plant to breakeven; this is done by setting NPV equal to zero and solving for the price of product. It should also be noted that a positive NPV indicates plant profit and project feasibility while a negative NPV indicates plant losses.

Capital costs for the plant were determined using the module costing technique [30]. Individual equipment base costs were calculated via Equation (2) [30].

$$\log\left(C_p^{\circ}\right) = K_1 + K_2 \cdot \log(A) + K_3 \cdot (\log(A))^2 \tag{2}$$

where, $C^{\circ}{}_p$ is the base cost of equipment made from carbon steel and designed for ambient pressure. K_1, K_2, and K_3 are constants found from Turton et al., [30] and are unique for each unit operation. A is the primary design parameter that is determined via mass balances, energy balances, and respective equipment design equations. Table 2 the K values for the units in the PFD.

Table 2. Constants used for equipment costs used in process flow diagram.

Model Unit	Qty	Units of A	K_1	K_2	K_3	Cost Modifier (F_{BM})
Jacketed Agitated Reaction Chamber	1	m^3	4.1052	0.532	−0.0005	4.00
Reciprocating pump (Pre)	1	kW	3.8696	0.3161	0.122	5.66
Reciprocating pump (Post)	1	kW	3.8696	0.3161	0.122	6.51
U-tube heat exchanger	1	m^2	4.1884	−0.2503	0.1974	4.59
Leaf filter press	1	m^2	3.8187	0.6235	0.0176	1.80
API fixed roof tank (miscanthus storage)	1	m^3	4.8509	−0.3973	0.1445	1.00
API fixed roof tank (product storage)	1	m^3	4.8509	−0.3973	0.1445	1.00

Once $C^{\circ}{}_p$ is calculated, it is multiplied by the cost modifier (F_{BM}) to determine the bare module cost (C_{BM}) of the equipment, as shown in Equation (3). F_{BM} incorporates not only material and pressure rating modifiers, but also indirect and direct costs for C_{BM}. Direct costs include equipment cost from the manufacturer and includes various costs ranging from piping and electric costs to labor costs. Indirect costs account from items such as freight costs, construction overhead, and additional engineering expenses. The overall fixed capital investment (FCI) is then calculated by summing up individual bare module costs. FCI also includes general fees, unforeseen costs (i.e., contingency costs), and supporting site costs (i.e., auxiliary costs). From previous literature, these additional costs are approximated as 3%, 15%, and 50% of C_{BM}, respectively; FCI is represented by Equation (4) [32].

$$C_{BM} = C_p^{\circ} \cdot F_{BM} \tag{3}$$

$$\mathrm{FCI} = \sum_{j}^{m} C_{BM\,j} + 0.03 \sum_{j}^{m} C_{BM\,j} + 0.15 \sum_{j}^{m} C_{BM\,j} + 0.5 \sum_{j}^{m} C_{BM\,j} \tag{4}$$

As shown in Equation (5), FCI is added with working capital (WC) in order to determine TCI. WC is the capital cost associated with the early phases of plant start-up and was approximated by Equation (6) [32]. It is important to note that the WC investment is not depreciated and is also recovered in the plant's cash flow in the final year "n".

$$\mathrm{TCI} = \mathrm{FCI} + \mathrm{WC} \tag{5}$$

$$\mathrm{WC} = 0.1 \cdot (\mathrm{FCI} + \mathrm{C_{OL}} + \mathrm{C_{RM}}) \tag{6}$$

where, C_{OL} and C_{RM} are operating labor costs and raw material costs, respectively. Where "raw materials" are the miscanthus and bituminous coal used for Co-HTC. F_k will be determined by summing up the after-tax net profit (ANP) and depreciation (d) for the year (k). ANP and F_k are determined with Equations (7)–(9) [30].

$$\mathrm{F_k} = \mathrm{ANP} + \mathrm{d} \tag{7}$$

$$\mathrm{ANP} = \mathrm{NP} - \mathrm{t} \cdot \mathrm{NP} \tag{8}$$

where NP is the net profit and t is the tax rate. Multiplying NP by t gives the profit/income that is taxed, so subtracting that quantity from NP itself yields ANP. NP is further defined as,

$$\mathrm{NP} = \mathrm{R} - \mathrm{COM_d} - \mathrm{d} \tag{9}$$

Equation (9) shows that NP is determined by subtracting expenses from revenue (R) which is represented by the cost of manufacturing (COM_d) and d. Equations (7)–(9) are combined to form Equation (10) [30].

$$\mathrm{F_k} = (\mathrm{R} - \mathrm{COM_d} - \mathrm{d}) - \mathrm{t} \cdot (\mathrm{R} - \mathrm{COM_d} - \mathrm{d}) + \mathrm{d} \tag{10}$$

Equation (10) can then be simplified into Equation (11).

$$\mathrm{F_k} = (\mathrm{R} - \mathrm{COM_d} - \mathrm{d})(1 - \mathrm{t}) + \mathrm{d} \tag{11}$$

COM_d is calculated with Equation (12) from general plant upkeep costs, C_{OL}, utility costs (C_U), C_{WT}, and C_{RM}. General plant maintenance is assumed to be an 18% the cost of the initial FCI.

$$\mathrm{COM_d} = 0.18\mathrm{FCI} + 2.73\mathrm{C_{OL}} + 1.23(\mathrm{C_U} + \mathrm{C_{WT}} + \mathrm{C_{RM}}) \tag{12}$$

A multiplier is used for C_{OL} in order to also account for administrative, supervisory, or laboratory costs. The multipliers for utilities, waste treatment, and transportation additionally account for any fluctuating or indirect costs. C_{OL} is sometimes referred to as fixed operating and maintenance (O&M) costs; C_U, C_{WT}, and C_{RM} are sometimes referred to as variable O&M costs. O&M parameters were summarized in Table 3. R is determined by multiplying the product produced each year by an estimated product price. The breakeven product is solved for by an incrementally changing the product price until the object function "NPV = 0" is satisfied through Equation (1). N_{OL} is the base number of operators per shift and is determined using Equation (13) [30].

$$\mathrm{N_{OL}} = \left(6.29 + 31.7 \cdot \mathrm{P}^2 + 0.23 \cdot \mathrm{N_{np}}\right)^{0.5} \tag{13}$$

where, P is the total number particulate handling unit operations and N_{np} is the total number of non-particulate handling unit operations. Salary was reported from INL economic analysis and the C_{OL} multiplier allows for calculation of additional costs associated outside operator labor.

Table 3. Fixed and variable operating and maintenance (O&M) parameters and economic parameters used for estimating operating labor and costs associated with manufacturing.

Fixed O&M Parameters			**Variable O&M Parameters**		
C_{OL} multiplier	2.76	[30]	Variable O&M multiplier	1.23	[30]
Operator salary ($/year)	52,700	[33]	Miscanthus ($/ton)	38	[34]
N_{np}	2	-	Bituminous coal ($/ton)	53.24	[35]
P	1	-	Water utility ($ m^{-3})	1.12	[36]
Op Labor	28	-	Waste water disposal ($/ton)	0.74	[37]
			Electricity cost ($ kWh^{-1})	0.066	[38]
			Cost of natural gas ($ m^{-3})	0.132	[39]
			Natural gas energy content (MJ m^{-3})	38.64	[40]
Economic Parameters					
Tax rate (%)	25	[41]	CRF	0.12	-
Annual interest rate (%)	10	[27,42]	Salvage value	0	[32]
Plant life (years)	20	-	Depreciation	7-year MACRS	[27,42]
Streaming factor (SF)	0.90	[33]	2016 CEPCI	541.7	[43]

2.4. Cost of Electricity

General economic parameters for determining NPV, capital investments, and cash flows are presented in Table 4. Most parameters have been assumed through NREL and NETL case study reports [27,42,44]. CRF is the capital recovery factory (Equation (14) [30]) which is used to calculate the total cost of electricity (COE). COE provides another parameter for evaluating plant costs and is calculated using Equations (15)–(18). CRF is used in Equation (15) to convert capital investments over the plant's lifetime into an annuity.

$$\mathrm{CRF} = \frac{\mathrm{i}(1+\mathrm{i})^{\mathrm{n}}}{((1+\mathrm{i})^{\mathrm{n}}-1)} \tag{14}$$

$$\mathrm{COE_C} = \frac{\mathrm{CRF}\cdot(\mathrm{FCI}+\mathrm{WC})}{\mathrm{SF}\cdot\mathrm{Plant\_Capacity}} \tag{15}$$

$$\mathrm{COE_F} = \frac{0.18\cdot\mathrm{FCI}+2.76\cdot\mathrm{C_{OL}}}{\mathrm{SF}\cdot\mathrm{Plant\_Capacity}} \tag{16}$$

$$\mathrm{COE_V} = \frac{1.23\cdot(\mathrm{C_U}+\mathrm{C_{WT}})}{\mathrm{SF}\cdot\mathrm{Plant\_Capacity}} \tag{17}$$

$$\mathrm{COE_{RM}} = \frac{1.23\cdot\mathrm{C_{RM}}}{\mathrm{SF}\cdot\mathrm{Plant\_Capacity}} \tag{18}$$

where $\mathrm{COE_C}$ is the capital COE, $\mathrm{COE_F}$ is the fixed operating COE, $\mathrm{COE_V}$ is the variable COE, and $\mathrm{COE_{RM}}$ is the raw material COE (sometimes referred to as fuel costs in literature). These separate costs are summed to form Equation (19), modified from literature [45].

$$\mathrm{COE} = \mathrm{COE_C}+\mathrm{COE_F}+\mathrm{COE_V}+\mathrm{COE_{RM}} \tag{19}$$

Table 4. Experimental data and flowrates used for overall material and energy balances for equipment design.

Parameters	Coal	Miscanthus	Blend
Plant rating (MWe)		110	
Thermal to electric efficiency (%)		35	
Reaction temperature (°C)		230	
Coal: Miscanthus solids ratio	1:0	0:1	1:1
Total feed water content (%)		70	
Gas production ($\times10^{-3}$ kg/kg solid Feed)	1.25	3.7	4.9
Total process feed (kg hr^{-1})	131,363	268,025	215,993
Total solid feed (kg hr^{-1})	39,409	80,407	64,798
Total water feed (kg hr^{-1})	91,954	187,617	151,195
Produced hydrochar on dry-basis (kg hr^{-1})	39,015	45,993	43,350
Total process liquid after treatment (kg hr^{-1})	92,999	221,734	172,326
Process liquid sent to wastewater treatment (kg hr^{-1})	82,545	210,236	161,488
Moisture dried from post-filter hydrochar (kg hr^{-1})	4932	5814	5480

2.5. Sensitivity Analysis

Sensitivity analysis was performed for the base case economic model to evaluate changes in the breakeven selling price. An individual process/economic parameter was changed, while all other independent process/economic parameters were held constant in order to evaluate the change in breakeven selling price. The individual parameter was changed to a lower sensitivity bound (LSB) and a higher sensitivity bound (HSB) with respect to the base case scenario; resulting breakeven prices were then plotted on a sensitivity chart (also known as a tornado plot). It should be noted that the determination of the LSB and HSB are based on previously observed market fluctuations (e.g., utility costs) or when not available, a general overall change in the parameter was assumed (e.g., FCI).

3. Results and Discussion

3.1. Plant Processing for Coal, Miscanthus, and Blend Hydrothermal Treatment

Hydrothermal processing feed rates were determined for coal, miscanthus, and 50:50 blend by using a 110 MWe power plant basis, assuming a thermal to electric efficiency of 35%, and applying experimentally determined batch reactor mass and energy yields at 230 °C (Table 4). The water content for treatment was reduced to 70% as solids to liquids loading is tertiary to process parameters temperature and residence time; complete feedstock submergence by the liquid phase at reaction temperature (i.e., volume of the liquid water is greater than the volume of the solid) is necessary for it to be considered undergoing HTC [46,47]. A miscanthus-only treatment facility would process more than twice the total feed of coal-only treatment as a result of the low miscanthus mass yield (57.2%) and the high coal mass yield (nearly 99%). Since the low miscanthus yield requires higher untreated biomass loading, the amount of water needed for treatment also increases; nearly three times the process liquid is sent for wastewater treatment at 210,236 kg hr^{-1} for miscanthus-only treatment than the coal-only treatment. The total solid feed into the reactor for Co-HTC that would meet the power requirement was determined to be 64,798 kg hr^{-1}, producing a hydrochar flowrate of 43,350 kg hr^{-1}. The synergistic interaction during Co-HTC causes the higher production of gas flow at 318 kg hr^{-1} despite coal-only and miscanthus-only gas flowrates of 49 and 298 kg hr^{-1}, respectively [23]. Co-HTC process flow conditions and mass balances for the solid, liquid, and gas inputs/outputs were used to approximate design parameters and equipment sizing, as economics analysis of Co-HTC was the objective of this study. Only one of each piece of equipment shown in Figure 1 and summarized in Table 2 was used for material processing and meeting power demand. Sizing, loading, and equipment quantity were then used to estimate capital costs.

3.2. Estimation of Capital Costs

Table 5 provides the capital cost analysis for the plant using 2016 pricing and C_{BM} and TCI distribution are presented. The total estimated C_{BM} for the plant is $5.30 million where pumping accounts for 45.9% of the total costs, followed by the heat exchanger and leaf filter contributing to ~21% of the total cost, each. Lastly, material storage and the reactor system accounted for 5 to 7.5% of C_{BM}. Material of construction used to calculate part of F_{BM} was SS-316, thus F_{BM} from the material was standard for comparison among all the equipment other than storage. SS-316 was used for the material of construction since process conditions are not corrosive enough to require more resistant and more expensive alloys, such as nickel-based alloys, for construction. Pressure factor contributions to F_{BM}, however, varied more as the heat exchanger and post-heat exchanger pump operate at higher operating pressures and temperatures. The leaf filter shared an unexpected higher amount of the C_{BM} cost compared to the other unit operations. However, the filter is limited by filter area and using a film thickness of 0.03 m [48] and a clearing rate of 0.25 hr^{-1}, can still only remove so much of the hydrochar; the lower filtration time is contributed to the hydrophobic nature of the hydrochar. Meanwhile, FCI, scaled from C_{BM} and WC then contribute to a TCI of $12.27 million. Breakeven cost will not be significantly affected by TCI since the quantity for each equipment is one. Though only one unit is used, contingent units are priced for in Equation 4. High manufacturing costs will contribute to a higher selling price, discussed in the next section as well as in the sensitivity analysis.

Table 5. Cost summary of Co-HTC plant producing fuel for 110 MWe coal power plant.

Capital Costs			**Manufacturing Cost**		
Item	**Cost**	**Cost Distribution**		**$/year**	**$/ton**
Reactor system	$396,246	7.50%	Estimated FCI upkeep	1,601,782	4.7
Pumping systems	$2,431,594	45.90%	Labor costs	4,085,936	12.0
Heat recovery system	$1,100,931	20.80%	Utilities	3,413,468	10.0
Solid product filtration and dewatering	$1,092,394	20.60%	Waste treatment	1,158,841	3.4
Storage	$275,762	5.20%	Raw materials	28,666,025	83.9
C_{BM}	$5,297,000	-	**Total**	**38,926,052**	**113.9**
FCI	$8,898,792	-			
WC	$3,370,118	-			
TCI	$12,268,910	-			
			Operating and Maintenance Cost		
COE ($ MWh^{-1})			*Fixed O&M costs*		
Capital COE	1.66		C_{OL} ($/year)	1,496,680	
Fixed operating COE	6.61		*Variable O&M costs*		
Variable operating COE	5.27		C_U ($/year)	2,775,177	
Raw material (fuel cost) COE	33.05		C_{WT} ($/year)	942,147	
Total COE	**46.60**		C_{RM} ($/year)	23,305,712	

3.3. Estimation of Manufacturing Costs

O&M base costs were determined via costs and parameters provided in Table 5. These base costs are then multiplied by their respective multipliers to account for indirect costs or miscellaneous costs (discussed earlier) and are incorporated with FCI upkeep in order to determine yearly manufacturing costs (shown in Table 5). Total manufacturing costs are $38.93 million per year, the bulk of those costs arise from purchasing raw materials for upgrading which comes out to $28.67 million per year. FCI upkeep and waste treatment account for 3–4% of the total manufacturing costs while labor costs and utilities makeup nearly 9–10% of the cost. The remaining 73% make up the cost of miscanthus and coal which convert to a cost of $83.9 to produce one ton of hydrochar product. Wirth et al., similarly saw that biomass supply costs for an HTC plant contributed to 37–59% of costs and was more significant than the cost of biomass-to-hydrochar conversion [49]. The manufacturing costs associated with raw materials are expected as purchasing costs for miscanthus and coal are $38 and $53.24 per ton. Total manufacturing cost is also equivalent to $113.9 per ton of hydrochar, giving initial insight into the breakeven cost, before solving Equation (1). The selling price of the produced hydrochar must be greater than $113.9 per ton in order to break even.

3.4. Estimation of Cost of Electricity (COE)

The total COE (Table 5) represents the plant's first year total cost of energy generation per total energy supplied annually. As observed with total manufacturing cost itemization, COE_{RM} accounts for most of the total COE. The COE for Co-HTC plant should be compared with the fuel COE from different power plants presented in NETL techno-economic analyses, rather than the total COE. This is important as Co-HTC is a means of upgrading waste or low value feedstocks into a combustible fuel, which will then be burned at a power plant. Thus, the total COE of the Co-HTC plant should only be compared to COE costs associated with fuel for the power plant in existing literature. The Co-HTC COE comes out to $46.60 MWh^{-1} for a plant operating at 110 MWe, whereas the fuel costs for pulverized coal using subcritical or supercritical boiler technology range from $22.8 to $29.8 MWh^{-1} (converted from to $2011 $2016) for plant capacities of 550 MWe [27]. These Co-HTC prices range from 56.4–105 % more than the base pulverized coal costs at approximately 20% of the net, plant capacity. The original COE for these coal plants range from $82.0 to $133.5 MWh^{-1}, where fuel costs are second to capital costs in terms of total makeup.

3.5. Breakeven Price and Sensitivity Analysis

With TCI and total manufacturing costs calculated, breakeven selling price were determined by setting NPV in Equation (1) equal to zero. Breakeven price for the baseline scenario using parameters in Tables 3 and 4 was determined to be $117.91 per ton of hydrochar. At $4.49 GJ^{-1}, the price of Co-HTC hydrochar is 2.30 times more than the average price of bituminous coal ($1.95 GJ^{-1}) and 1.31 times more expensive that the cost of natural gas ($3.42 GJ^{-1}) on an energy content basis. The high selling price for the hydrochar is in accordance with the high manufacturing costs and COE discussed earlier as miscanthus and coal purchase cost were $38 and $53.24 per ton of respective feedstock. Since selling price was impacted significantly by current feedstock prices, the change in selling price was evaluated by assuming different raw material purchasing costs in a sensitivity analysis. Additionally, other process parameters were increased and decreased to observe their contribution to the selling price. Table 6 provides all parameters altered for the sensitivity analysis; the baseline parameters are presented with the ranging sensitivity values as well as the resulting selling prices. The percent change in breakeven costs with respect to the baseline breakeven cost can be found in Figure 2. Hydrochar throughput and raw material prices have a more significant effect on final selling prices than manufacturing related costs. The latter was previously observed in previous sections, as breakeven prices can decrease by 14% by lowering feedstock price or can increase by approximately 10%. This variation indicates that co-treatment costs can improve by utilizing cheaper biomass options such as waste feedstocks, which have been previously shown to be upgraded via HTC [17]. Similarly, lower rank coal (e.g., lignite) fuel properties can benefit from HTC treatment [50,51] and can be purchased at lower costs [35].

Table 6. Parameter ranges for sensitivity analysis used to determine breakeven cost ranges.

Items	Baseline Scenario	Sensitivity Range	LSB Breakeven Cost ($/ton)	HSB Breakeven Cost ($/ton)
Baseline scenario breakeven price ($/ton)	117.24	-	-	-
FCI ($ 10^6)	8.90	8.01–10.23	116.44	118.44
Hydrochar yield (%)	66.9	60–74	130.58	106.1
Hydrochar HHV (MJ·kg^{-1})	26.1	24–29.5	116.03	119.09
Miscanthus price ($/ton)	38	20–50	100.69	128.27
Coal price ($/ton)	53.24	45.4–66.7	110.00	129.58
Waste treatment ($/ton)	0.74	0.5–2.0	116.14	123.01
Water utilities ($ m^{-3})	1.12	0.66–2.11	115.27	121.52
Cost of natural gas ($ m^{-3})	0.132	0.092–0.300	115.85	123.1
Power rating (MWe)	110	55–550	130.85	106.88

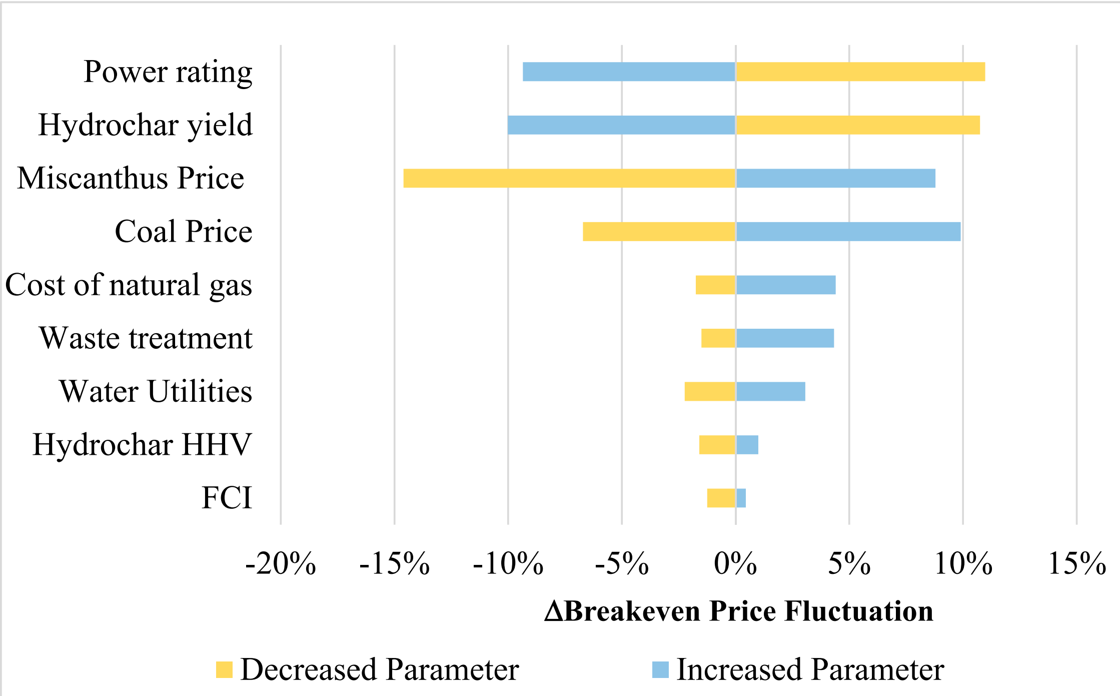

Figure 2. Sensitivity analysis showing change in breakeven price of product with respect to baseline breakeven cost.

Retaining more of the reactor feed as hydrochar lowers breakeven price as there is more product to sell. If reaction yield is increased by just 4%, breakeven price drops down to $106.10 per ton from the base case cost of $117.24 per ton. In the same form of price impact, increasing plant production (i.e., increasing feed flowrate) by increasing power rating demand produces more hydrochar. As expected, this lowers breakeven price as there is more product to sell. Scaling down power demand to 55 MWe, requires less hydrochar production for burning and consequently increases the base cost to $130.59 per ton while a power rating of 550MWe plant decreases the selling price by 9% to $106.88 per ton. Changing power demand for sensitivity analysis changes other costing parameters (quantity of equipment, equipment sizing parameters, utility usage, labor, etc.) since reactor throughput increases significantly. Thus, breakeven price was evaluated for different power demand loads (Figure 3). Breakeven price decreases with loading capacity, as is expected with economy of scale, and begins to plateau at 220 MWe.

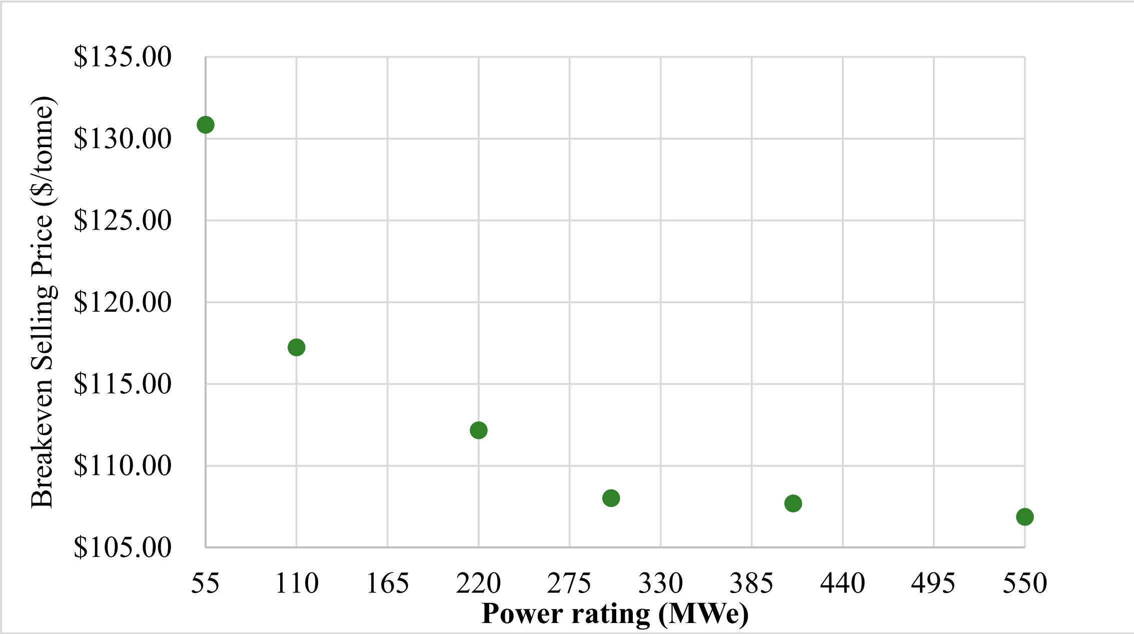

Figure 3. Breakeven selling price for hydrochar at different power ratings.

Although a power rating of 550 MWe and 55 MWe have similar breakeven costs to hydrochar yields of 74% and 60%, the impact from hydrochar yield is much more impactful in changing breakeven costs. The plant production for a power rating of 550 MWe produces 1.71×10^6 tons of hydrochar per year, while plant production for the 110 MWe load at 74% mass yield produces only 3.78×10^5 tons of hydrochar per year. Both cases are approximately $107 per ton despite an order of magnitude difference in production. Even at 300 MWe, where breakeven price in Figure 3 starts to steady, 9.32×10^5 tons of hydrochar per year are produced. Economy of scale allows for reduced breakeven cost as the plant is scaled up (observed with power demand), however the increase in equipment capital and increase in manufacturing cost offsets additional revenue created from increased hydrochar production. Overall, biomass to coal ratio can be adjusted to produce higher yields and feedstock flowrate can be increased for more hydrochar processing, however, the latter should not be done where additional equipment and manufacturing costs increase to the point of counterbalancing the growth in profit.

4. Conclusions

A Co-HTC process producing 43,350 kg hr^{-1} was designed to deliver fuels for a 110 MWe power plant using Clarion coal #4a and miscanthus with 50:50 (wt % dry basis) blend. Total capital investment was estimated at $12.7 million, where pumping was the predominant capital investment followed by heat exchangers and filtration. Total manufacturing cost is $38.9 million per year and equivalent to $113.9 per ton of product produced, indicating that the product selling price cannot be lower than this cost to breakeven. The cost of electricity for making Co-HTC hydrochar is around $46 per MWh^{-1}, nearly twice the cost of the fuel costs associated with standard coal-fired plants. The breakeven selling price of the produced hydrochar was $117.24 per ton, where the cost of purchasing feedstocks for upgrading accounted for most of the breakeven price. Sensitivity analysis showed that power rating, cost of coal and miscanthus, and hydrochar yield could reduce this breakeven selling price significantly. Attempting to treat co-treat abundant waste feedstocks and lower ranks coals via HTC can provide lower breakeven costs as these raw materials can be purchased at cheaper prices and should be considered for future studies.

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List of Initialisms/Acronyms

SF	Streaming factor
MACRS	Modified accelerated cost recovery system
ANP	After-tax net profit
C_{BM}	Bare module cost
COE	Cost of electricity
Co-HTC	Co-Hydrothermal Carbonization
C_{OL}	Operating labor costs
COM_d	Cost of manufacturing without depreciation
CRF	Capital recovery factor
C_{RM}	Raw material (or fuel) costs
C_U	Utility cost
C_{WT}	Waste treatment cost
d	Depreciation
EOIR	Energy output to input ratio
F_{BM}	Bare module cost modifier
FCI	Fixed capital investment
F_k	Annual after-tax cash flow
HHV	Higher heating value
HSB	Higher sensitivity bound
HTC	Hydrothermal Carbonization
i	Annual interest rate
k	Evaluation year
LSB	Lower sensitivity bound
N_{NP}	Total number of non-particulate handling unit operations
N_{OL}	Base number of operators per shift
NP	Net profit
NPV	Net present value
O&M	Operating and maintenance
P	Total number particulate handling unit operations
t	Tax rate
TCI	Total capital investment
WC	Working capital

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