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Mitigation of Municipal Biosolids via Conversion to Biocrude Oil Using Hydrothermal Liquefaction: A Techno-economic Analysis

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Mitigation of Municipal Biosolids via Conversion to Biocrude Oil Using Hydrothermal Liquefaction: A Techno-economic Analysis

by

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Dedication

Dedicated to my sister Deidra, for never being too busy to hear me complain or to exchange cat videos.

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Abstract

Mitigation of Municipal Biosolids via Conversion to Biocrude Oil Using Hydrothermal Liquefaction: A Techno-economic Analysis

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In this techno-economic analysis, we have shown that hydrothermal liquefaction (HTL) technology can be integrated with existing biosolids management facilities that utilize anaerobic digestion and biogas capture. The overall process converts raw sewage sludge to refinery-ready biocrude oil. The Hornsby Bend Biosolids Management Plant (HBBMP) in Austin, TX is used as a case study. First, the operation of the plant without any modification was modeled and validated with field data. A standalone HTL processing unit was then considered as an add-on to the existing infrastructure. Technical and economic parameters were obtained from literature and experimental data. The results showed that savings of about $32 M over current operation with a payback period of 4.35 years were achievable at HBBMP. A nation-wide implementation could result in production of almost 4.5 million barrels of upgraded biocrude oil per year while offsetting about 330,000 metric tons of CO2 equivalent greenhouse gas emissions annually.

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Chapter 1

Introduction

1.1 Background and Motivation for the Study

Sewage sludge management is a growing, global problem. In the U.S. sewage sludge is often converted to biosolids in accordance with federal and state regulation in order to be re-used or properly disposed of [1]. The U.S. Environmental Protection Agency (EPA) estimates that the U.S. alone currently produces over 8 million dry tons of biosolids each year [2]. Approximately 40% of this is disposed of using expensive, non-beneficial methods such as incineration and surface disposal [2]. Conversion of these waste streams into biocrude oil would enable the production of an economically-valuable, energetically-efficient product from what is typically a problem for biosolids management facilities.

There are a wide variety of bio- and thermochemical processes that can be used to synthesize biofuels. In this study we focused on hydrothermal liquefaction (HTL), which is a thermochemical process that takes advantage of the reactive, subcritical properties of water to convert biomass into a liquid fuel. In its subcritical stage, water acts as a catalyst and reactant, which allows for direct conversion of biomass without the need for energetically-intensive drying steps seen in other biofuel processes [3]. The sludge and biosolids waste streams already exist in slurry form, requiring little to no additional preparation prior to HTL processing.

The literature and our own experiments show that pre- and post-digested sludge, as well as farm-generated manure, are viable feedstocks for HTL [3–5]. It has also been shown that HTL can mitigate the environmental impacts of sludge and biosolids disposal by: 1) significantly reducing the heavy metal leaching rates and ecological risk index of all HTL products, and 2) removing pathogens using the high processing temperature [6]. The liquid fuel product of HTL is commonly referred to as biocrude. Compared to petroleum crude, biocrude differs mostly in its elevated nitrogen and oxygen contents [3,5,7,8]. This requires that the biocrude be hydro-treated prior to refining [7,9]. Once treated the biocrude can serve as a petroleum crude blendstock without significant refinery infrastructure changes [10].

Additionally, products refined from biocrude may be considered under the Energy Independence and Security Act of 2007 (EISA) and the updated Renewable Fuel Standard (RFS2). This policy mandates yearly, minimum biofuel usage standards in the US, increasing to 36 billion gallons by 2022 [11–13]. Currently the most common and widely produced biofuel is corn-based ethanol, of which the advantages and disadvantages are environmentally and politically debated. Converting waste streams such as sludge, manure and biosolids into biofuel could help meet this biofuel standard by contributing to national energy independence and reduced greenhouse gas (GHG) emissions, while also reducing valuable land usage and diversion of food crops.

The purpose of this study was to evaluate the economic and energetic feasibility of integrating an HTL pathway to existing biosolids production plant infrastructure. The techno-economic (TE) model was built on an assembly of published, experimental and economic HTL data, current operational data from Hornsby Bend Biosolids Management Plant (HBBMP) and thermodynamic property data from Aspentech's Aspen Plus modeling software [14]. This study also considered environmental impacts and sustainability of the proposed production pathway.

1.2 Techno-economic Analysis

Figure 1.1 presents the framework for the TE analysis that is utilized in this study. TE analysis is a strategy that integrates process modeling, mass and energy balances, economic factors and environmental sustainability into a single report. This enables both effective comparison of technologies and design and optimization of processes to meet economic, energetic and environmental targets.

One approach in evaluating emerging renewable fuel technologies via TE analysis is to incorporate a discounted cash flow analysis in order to calculate a minimum fuel selling price [15–18]. Alternatively, this study leveraged a net present value (NPV) approach in order to compare current operation at HBBMP (Base Case) to the proposed case where HTL is incorporated into the existing infrastructure (Case 1). The goal was for the model to predict return on investment (ROI), pay-back time, energy return on energy investment (EROI), fuel production, environmental impact and sustainability.

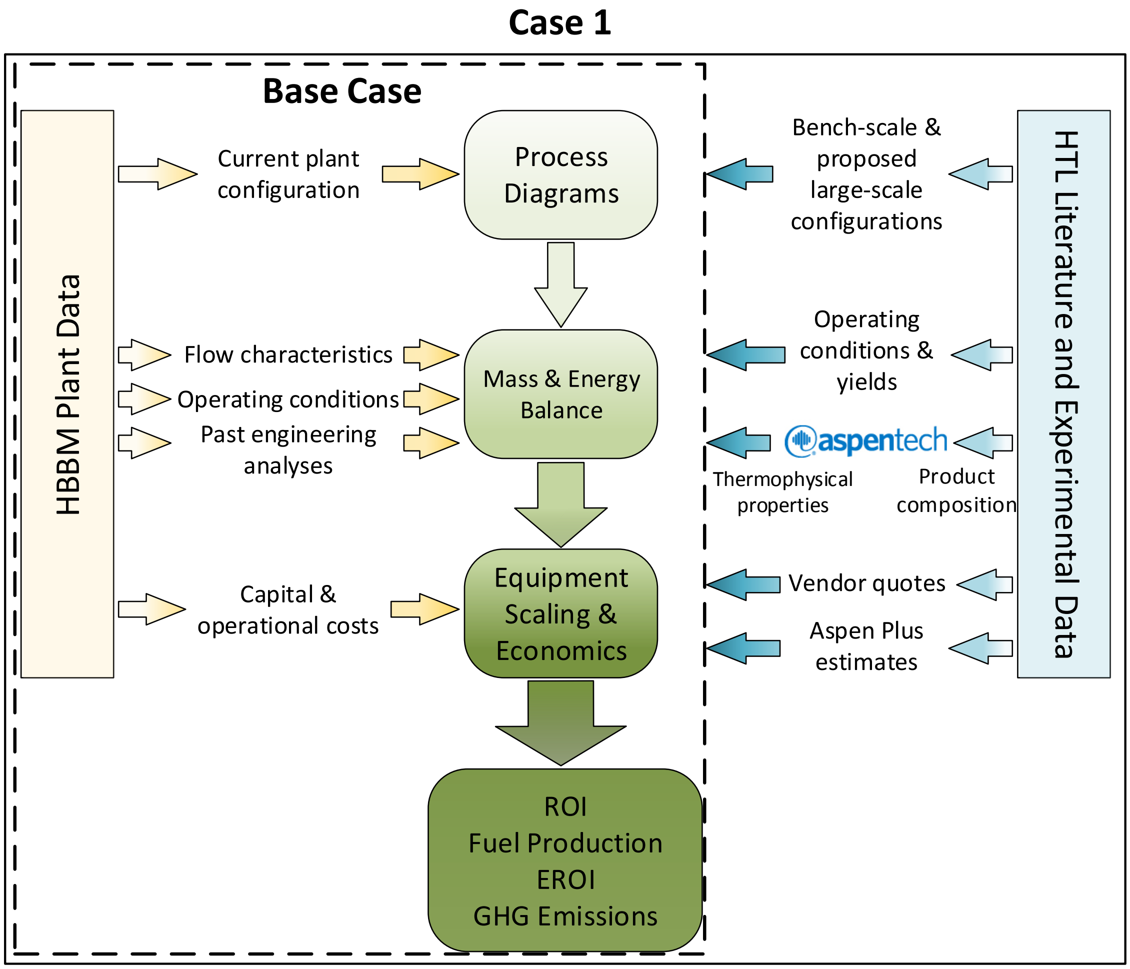

Figure 1.1: Techno-economic approach for comparing the operation of HBBMP with and without HTL (Case 1 and Base Case respectively)

1.3 Sensitivity Analysis

Sensitivity analyses were performed using the SensIt® MS Excel plug-in from TreePlan Software [19]. These analyses assisted in understanding the impacts of relevant parameters on the following model outputs: 1) EROI, 2) ROI and 3) GHG emissions. Operating conditions at HBBMP are highly variable and thus most parameters were given as a range of values. Sensitivity analysis allowed us to apply the full range of possible values and identify which parameters affected the final outcomes the most and in what way. Sensitivity reporting was especially important with regards to the significant uncertainty associated with parameters such as crude oil price and discount and tax rates.

Two-factor sensitivity was also performed. This analysis compiles all possible combinations of parameters to show the sensitivity of varying two parameters simultaneously. Results from a two-factor sensitivity analysis can make it easier to realize the full potential of projects based on unproven technology. Two-factor analysis is most beneficial for projects in which multiple parameter adjustments are realistic, or for multiple parameters that are expected to change with time, such as crude oil price and federal tax rates.

1.4 ORGANIZATION OF THE THESIS

Chapter 2 of this study begins with process modeling and mass and energy balances, which were the core of the overall analysis. This chapter includes full process diagrams of both cases. Model validation was performed in comparison to current plant data and past City of Austin (CoA) reports and data. Results of this chapter include estimated fuel production, energy consumption, EROI and a sensitivity analysis.

Chapter 3 presents work which utilized the mass and energy balance results from Chapter 2 to estimate economic parameters.[1] The design of the HTL and upgrading systems are discussed in terms of individual component cost, scaling and adjustment. Major equations and assumptions are included. The results of Chapter 3 include ROI, pay-back

[1] Results, findings, opinions and recommendations presented by the authors in Chapter 3 should not be used for investment purposes without further study and understanding of associated uncertainties. This study should be used for estimation purposes only.

time and total capital investment. Single and two-parameter sensitivity analyses were performed with respect to ROI.

Chapter 4 continues the TE analysis by estimating environmental impact from GHG emissions. Three GHG analyses were performed. The first analysis compared sludge HTL emissions to those of petroleum-derived gasoline. The second compared sludge HTL to current operation at HBBMP as a biosolids mitigation strategy in terms of local GHG impact. The third analysis compared sludge HTL to the business-as-usual case where HBBMP and gasoline production emit GHGs simultaneously.

Analysis performed in Chapter 5 utilizes the mass balance and GHG emissions models described in Chapters 2 and 4, respectively, to estimate the impact of nation-wide sludge HTL implementation. These results presented in this chapter give a high-level estimate of the future potential of sludge HTL as a fuel producer.

Finally, Chapter 6 includes a discussion on the overall project summary and possible future studies that would benefit sludge HTL technology.

Chapter 2

Mass & Energy Balance

2.1 Analysis

2.1.1 Base Case Scenario

Microsoft Excel 2013 was used to construct a model that characterizes yearly-averaged, typical operation of HBBMP. We referred to this scenario as the Base Case. The Base Case was built from and validated by process data and engineering reports provided to us by the staff at HBBMP and Environmental & Regulatory Services, both of which are a part of the Austin Water Utility (AWU). Table 2.1, at the end of this section, presents a summary of the operational parameters used for the Base Case scenario.

Figure 2.1 shows the schematic of the current processes for managing sewage sludge and biosolids at HBBMP. The plant processes two main sludge flows which are a mixture of primary and secondary activated sludge from AWU's two main wastewater treatment plants: South Austin Regional (SAR) Wastewater Treatment Plant (WWTP) and Walnut Creek (WC) WWTP. These incoming streams were not included in model calculations due to uncertainty from only having a single month of data. In May 2014, SAR contributed approximately 0.689 million gallons per day (MGD) at 2% total solids (TS) and WC contributed approximately 0.7 MGD at 2.6% TS [20]. A third stream from the on-site water treatment facility contributed about 0.04 MGD at 2% TS. This smaller stream is made up of recovered solids from the various thickening and dewatering processes in the main plant [20,21].

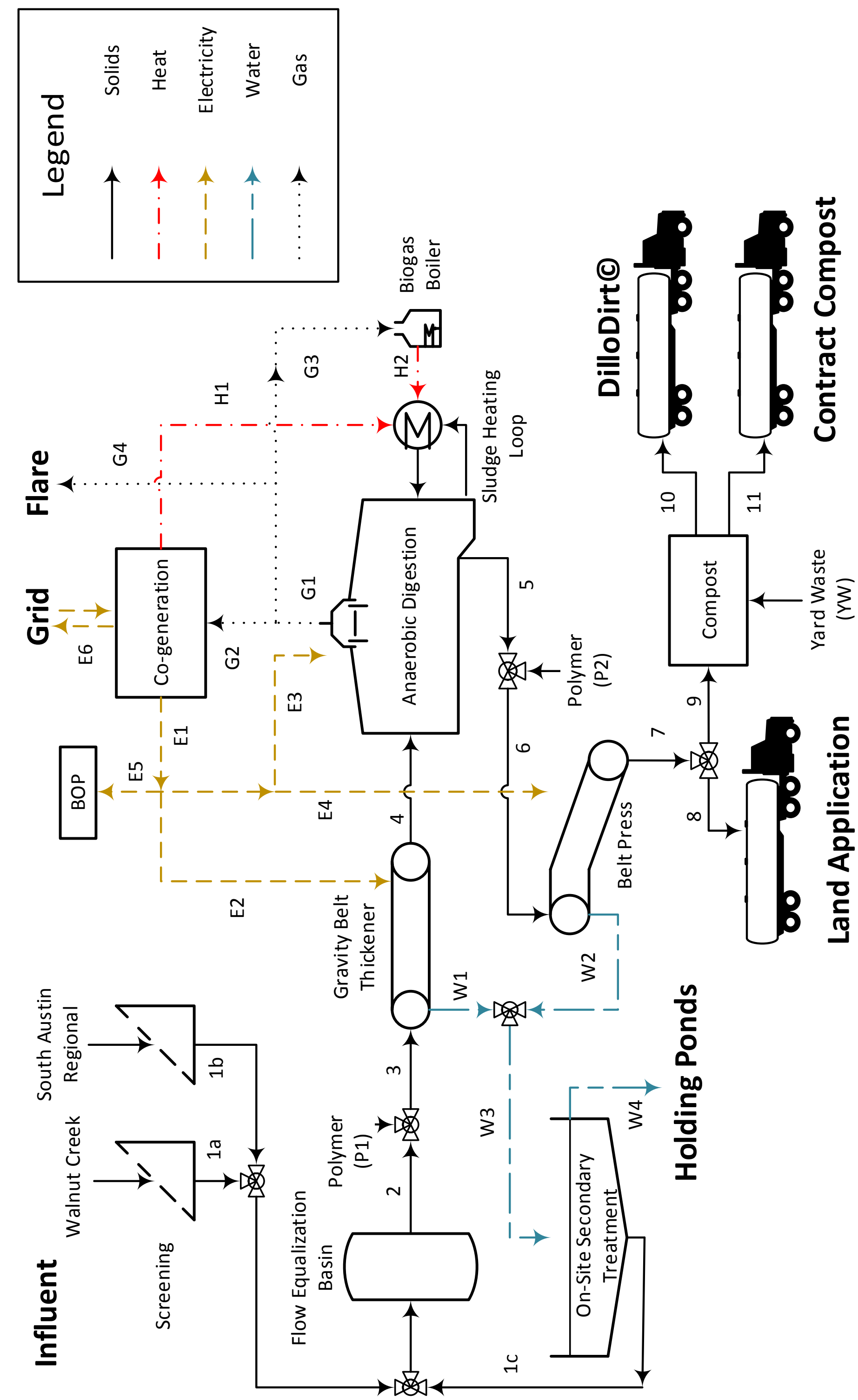

Figure 2.1: Process flow diagram for Base Case scenario

The two main streams from SAR and WC are screened for large objects, such as storm debris and garbage, and then combine with the recycle stream in a flow equalization basin (FEB), which serves to damp the variation in the incoming flow rates and provide a steady effluent flow [22]. The FEB also serves as the input to the model due to frequent flow measurements made there. After leaving the FEB, a cationic polyelectrolyte is added to the stream at a rate of about 5-10 lb/dry ton of solids (dt) [21,23]. This polymer causes flocculation of the solid particles and increases the efficiency of the gravity belt thickeners (GBT). The GBTs concentrate the flow to approximately 7% TS where it is then pumped to the anaerobic digesters.

The HBBMP digester complex is comprised of eight digesters, each with a capacity of 2 MG. The digestion process creates two products: 1) biogas from the organic breakdown of volatile solids (VS), and 2) Class B biosolids at approximately 5% TS [20]. Biogas from anaerobic digestion is generated at a rate of about 0.75-1.12 m^3/(kg-VS destroyed) and is typically composed of approximately 62% methane and 35% carbon dioxide on average [20,22]. This composition contains an energy content of approximately 20.5-22.4 MJ/m^3 (570-620 BTU/cf) [24]. This is compared to about 39 MJ/m^3 (1000 BTU/cf) for natural gas [24]. Digester gas also commonly contains hydrogen sulfide (H_2S), moisture and siloxanes [22,24]. HBBMP actively removes H_2S and siloxanes prior to combustion due to their corrosive and abrasive properties [21]. The majority of the generated biogas is used to fuel a single GE Jenbacher Type 3 cogeneration (co-gen) unit. The remaining biogas is either sent to boilers to produce additional heat, or flared off in order to reduce GHG emissions.

The co-gen is capable of generating a maximum 848 kWe/1118 kWt and supplies all of the electricity needed to run the plant, via net-metering with the grid, and the heat needed to sustain digestion temperatures of 35°C for most of the year [25]. During the winter months additional heat is supplied by the biogas boilers at a rate of about 3500 GJ/hr via hot water-loop heat exchangers [24]. Class B biosolids are discharged after an approximately 30 day residence time and then pumped to the belt presses (BP) where additional polymer is added for further dewatering [21]. The dewatered biosolids, referred to as "cake," are then divided into three product streams: 1) land application, 2) contract composting, and 3) Dillo Dirt™ production.

In general, the quality of biosolids material is divided into two pathogen density levels, Class A and B, according to the EPA Title 40 CFR Part 503 [1]. Class B is the minimum requirement for land application, surface disposal and incineration. HBBMP biosolids meet Class B requirements through the anaerobic digestion process. At HBBMP about 50% of biosolids production, by volume, is used as agricultural land application [21]. The other half of the biosolids material is combined with approximately 75 MT/d of city-generated yard waste in order to be composted.

Composting is considered by the CFR as a pathway to achieve Class A biosolids status [1]. Approximately half of the HBBMP compost stream is managed by contractors and the other half is used by HBBMP to produce Dillo Dirt, which is an EPA-certified, Class A compost that is used in parks and gardens around the City of Austin. There are no restrictions on its application.

All three product streams are produced at a monetary net loss when capital and fixed costs are considered, which is standard for biosolids management plants [21]. Dillo Dirt is the most monetarily attractive output for the Base Case scenario due to having the lowest net production cost.

Despite a monetary loss, HBBMP offsets many other costs and additional benefits are gained in the following ways: 1) Land application directly offsets solid waste that would otherwise be incinerated or sent to surface disposal. In order to incinerate the waste, specialized incinerators must be built, which would result in extensive capital cost [1]. Heavy metal pollution and hydrocarbon emissions could also result from this method of disposal. 2) Land application and composting offset landfill fees at a rate of about $33/ton in the Austin area [26]. These offset fees add up to around $1M/y in savings [21]. Additionally, landfilling contributes to land-use issues and long-term emission implications, which are more difficult to quantify. 3) Land application offsets the energy and emissions-intensive process of nitrogen fertilizer production.

Table 2.1: Base Case model parameters

Parameter	Assumed Value		Source
GBT solids capture	85 %		[27]
GBT polymer dose	3 g/kg	(6 lb/dt)	[21]
Digester VS destruction	50 %		[22]
Digestion temperature	35°C	(95°F)	[24]
Biogas production rate	0.98 m3/kg VS	(15.7 cf/lb VS)	[22]
Biogas energy content	21.6 MJ/m3	(580 BTU/cf)	[24]
BP solids capture	90 %		[27]
BP polymer dose	8.5 g/kg	(17 lb/dt)	[21]
Incoming yard waste	74563	(30000 ton/yr)	[27]

2.1.2 Case 1 Scenario

Case 1 expands on the Base Case by feeding the dewatered biosolids cake directly into an HTL and upgrading system (Figure 2.2). The upgrading process generates a final product that is very similar to petroleum crude in elemental composition and heating value [28,29]. Thus, upgraded biocrude price can be accurately modeled as equivalent to petroleum crude price.

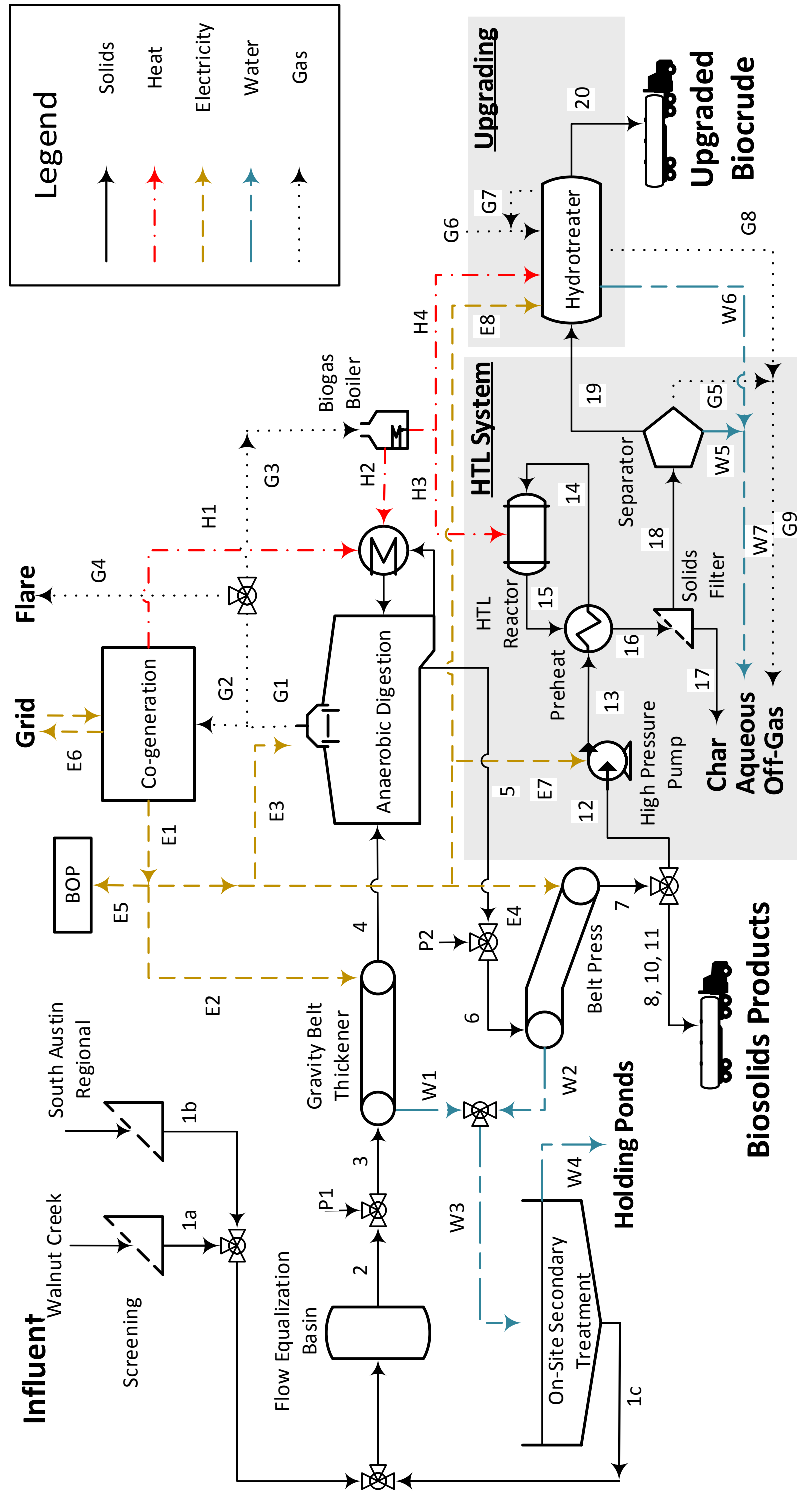

Figure 2.2: Process flow diagram for the Case 1 scenario

Case 1 was modeled using the proposed process configuration, yields and operating conditions from HTL literature and in-house experimental data. Aspen Plus was used to calculate the thermophysical properties of the biocrude products, based on estimated molecular composition from the literature, at their associated high pressure and temperature conditions [14,16]. It is important to note that these molecular biocrude compositions were estimated from algal feedstocks, so a major assumption is that biosolids-based biocrude will be similar. Sludge streams were assumed to follow the thermophysical properties of water due to their high water, low solids content.

In Case 1 diverted biosolids cake is sent to a high pressure pump that increases the operational pressure to about 21 MPa (3000 psi). A heat exchanger transfers energy from the reactor products to the cake slurry, increasing the temperature to approximately 280°C. A biogas-fired hot oil loop then heats the slurry to its reaction temperature of 350°C in the main reactor.

Reaction products consist of four main phases: solids, aqueous, gas and biocrude oil. First, solids are recovered from the product stream through filtration and are typically referred to as "char." In the literature char yields ranged from 1-36% with reported energy content of about 4.6-13 MJ/kg (1100-3100 cal/g) [16,30,31]. Next, pressure is decreased and separated into gas, aqueous and biocrude phases. Through in-house experiments we observed that once the solids are removed from the product stream, oil and aqueous phases spontaneously separate. Additionally it was found that the biocrude yield on HBBMP dewatered biosolids was about 30% on VS (30 wt% afdw) [29]. Gas yield was assumed to be 13% based on literature data [16,30,31]. Assuming a 10% char yield, the aqueous phase yield came out to about 43%.

The hydrotreating process is similar to the HTL process in that it requires high temperature and pressure on the order of 400°C and 10.5 MPa (1530 pi) [16]. Hydrogen gas and cobalt-molybdenum catalyst are needed in order to remove nitrogen and oxygen from the oil. The overall process was simplified to a single block in Figure 2.2. Within this block, pressure is maintained from HTL separation conditions and hydrogen gas is added at a rate of 0.05 kg H_2/kg biocrude [7,16,31]. The hydrogen is assumed to be delivered periodically by truck and stored in a pressurized tank on-site. The biocrude oil is then pumped through a heat exchanger with the hydrotreated products, increasing the temperature to approximately 171°C. Then, the biocrude oil comes into contact with the catalyst and is heated to the process temperature of 400°C in the main reactor. Excess hydrogen is captured and recycled. Upgraded biocrude was assumed to be produced at a yield rate of 80% [4,16,18].

Table 2.2: Case 1 model parameters

Parameter	Assumed Value		Source
HTL reactor temperature	350°C	(662°F)	[16,17]
HTL reactor pressure	20684 kPa	(3000 psi)	[16,17]
Biocrude yield	30 wt% afdw		[29]
Cake heat capacity	4.187 kJ/kg-K		
Upgrading temperature	400°C	(752°F)	[16]
Upgrading pressure	10549 kPa	(1530 psi)	[16]
H_2 feed rate	0.05 kg/kg biocrude		[4,16,18]
Catalyst loading	0.625 wt/hr per wt catalyst		[16]
Upgrade yield	80 %		[4,16,18]
Upgraded biocrude density (@40°C)	0.78 kg/L	(6.5 lb/gal)	[28]

2.2 Results & Discussion

2.2.1 Model Validation

Base Case results were validated with values interpolated from HBBMP flow projections reported by the CoA, which are summarized in Table 2.3. The flow points in Table 2.3 were chosen due to their availability in the report as well as their energetic and economic importance. In particular the mass of dewatered cake from the BP was chosen because it is the output for the Base Case and the material link between the Base Case and Case 1.

Table 2.3: Model validation parameters

Parameter	2012[a]	2030[a]	2014[b]	Base Case	Difference
FEB effluent [dt/d]	92	147	98	99[c]	0.6%
Dewatered cake [dt/d]	54	87	58	55	4.4%
Biogas [mmcf/d]	0.85	1.35	0.91	0.89	1.5%
GBT polymer [ton/y]	100	162	107	108	0.8%
BP polymer [ton/y]	175	284	187	190	1.7%

[a]Projected from 2009 [32]
[b]By linear interpolation
[c]Measured value [21]

Overall, the model showed less than 5% difference in mass flow compared to the CoA reported projections, with a span of 0.6-4.4%. The lowest difference was the FEB effluent, which was the input to the model. Sludge production is a function of city population, which typically increases linearly across time. Thus, uncertainty should be low with regards to the flow estimates. The highest difference was with the cake output. This was expected due to the number of systems and assumptions made between the input and output. HBBMP has also been in an almost constant state of upgrading and retrofitting for the last few years [21]. This increases uncertainty in digester and dewatering performance assumptions. A maximum difference of less than 5% was deemed acceptable to ensure accuracy of the flow moving forward to Case 1.

2.2.2 Mass and Energy

Total output was about 6.9 MT/d (55 bbl/d) of upgraded biocrude oil and 2.7 MT/d of solid char for Case 1 in 2014 (Table 2.4). These amounts were a result of the economic optimization of the model for maximum daily production value, which is described in Section 3.1.1. This optimization resulted in 100% of the biosolids cake being diverted to HTL. The initial inputs to the model were the FEB effluent flow, TS and VS content. The yearly-averaged flow at this point was measured from October 2013 – September 2014 to be about 89.5 dry MT/d (98.7 dtpd) [21]. From this input the model reports about 50 dry MT/d (55 dtpd) of biosolids output at the BP that was then fed into the HTL system.

Table 2.4 reports the mass and energy balance results, as well as EROI for the Base Case and Case 1. EROI was calculated simply as total energy output divided by total energy input. The Base Case and Case 1 EROIs were calculated to be 2.78 and 1.68 respectively. Energy outputs were considered to be biosolids cake for the Base Case, upgraded biocrude oil and char for Case 1 and excess biogas energy and electricity for both cases. Electric energy was converted to its thermal energy equivalent using the efficiency of the co-gen. In the Base Case only 48% of biogas by volume was utilized. This large amount of excess energy accounts for the greater Base Case EROI. Complete mass and energy balance results can be found in Appendix B.

Table 2.4: Mass and energy balance summary for Base Case and Case 1

Description	Base Case		Case 1	
	[dry MT/d]	[dtpd]	[dry MT/d]	[dtpd]
Mass				
Sludge input	89.5	98.7	89.5	98.7
Biosolids	50	55.2	-	-
Char	-	-	2.72	3.0
Upgraded biocrude	-	-	6.85	55 bbl/d
Energy input [MWh_t/d]				
Thermal	29.6		61.1	
Electricity[a]	34.8		40.2	
Energy output [MWh_t/d]				
Biogas	93.7		62.2	
Electricity[a]	20.4		15.0	
Biosolids/Biocrude + Char	65.2		93.5	
EROI	2.78		1.68	

[a]Assuming 36.9% conversion efficiency [25]

Energetically, both cases were completely sustained by biogas, through either the co-gen unit or direct combustion in the boilers. However, both cases require additional non-sustainable products in order to operate, such as dewatering polymer and hydrogen for upgrading. These external requirements make it difficult to label either case as a fully self-sustaining process.

2.3 Sensitivity

Figure 2.3 shows that EROI was most sensitive to biocrude yield, followed by biogas generation rate. These parameters were directly related to the generation of products with the highest energy density. Thus, these results were expected. For the lowest reported biocrude yield of 9.4 wt% afdw, EROI was at its minimum of 1.13. Our in-house experiments show much higher yields in the range of 30-40 wt% afdw, which produce an

EROI of about 1.95. The large difference in yields could be due to geographic variance in biosolids material or biosolids plant operating conditions. Future testing should be done at multiple plants across the US with a focus on biocrude yield if EROI is a concern. Increased biogas production increases energy output, but unless some sort of distribution system is implemented this extra energy is not utilized.

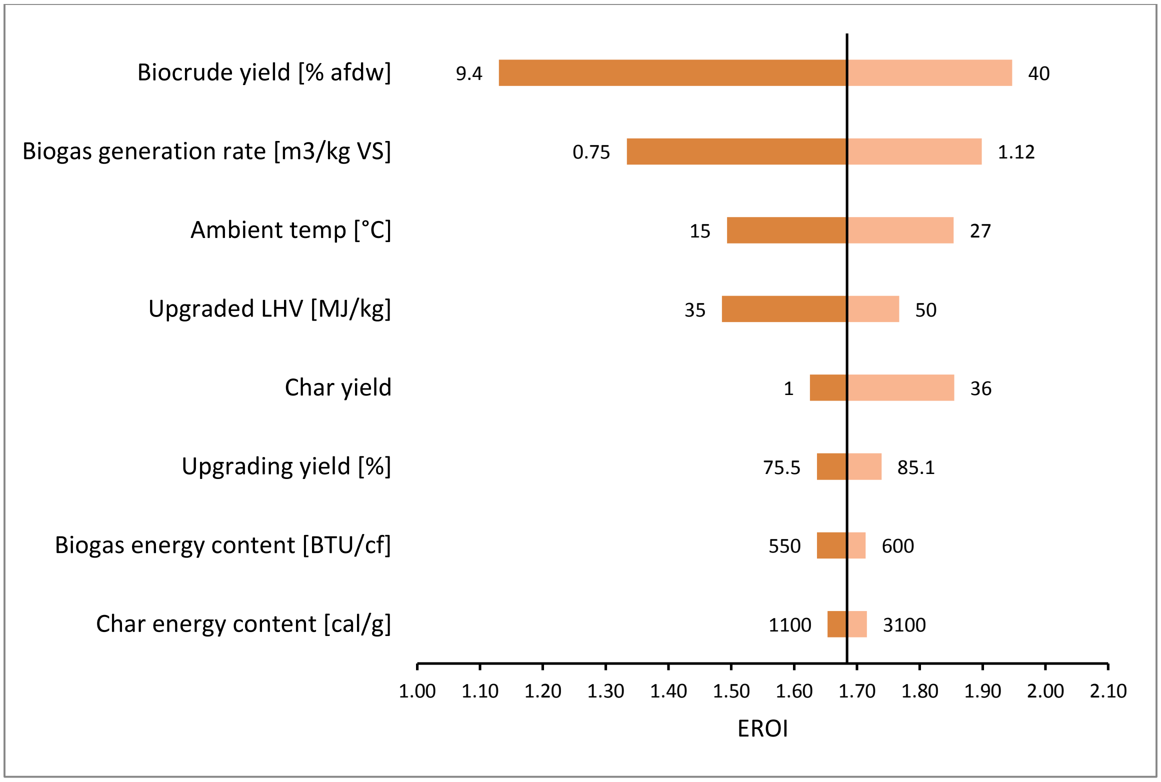

Figure 2.3: Sensitivity of chosen parameters with regards to EROI

Ambient temperature had an interesting and evenly distributed effect on EROI. Increased local temperature decreased the energy required to maintain digestion temperature and for HTL and upgrade heating. This shows that a greater EROI can be achieved at plants located in warmer climates. The temperature range used in this study was the span of local, yearly-averaged high and low temperatures [33]. This also shows that the EROI should be expected to fluctuate between about 1.5 and 1.85 annually.

2.4 CONCLUSION

Overall we see that the model produces relatively accurate results in terms of mass flow. Mass flow is very important because all proceeding analyses depend on it. Case 1 was found to be sustainable with regard to energy requirements, but only semi-sustainable overall due to required external inputs such as dewatering polymer and hydrogen. Case 1 was able to produce 55 bbl/d of upgraded biocrude oil based on current biosolids production rate. Going forward this production rate will increase with increasing sludge input.

An EROI of 1.68 is favorable when compared to other biofuel pathways. As reported by Liu et al., cellulosic and corn ethanol were calculated to have EROIs of around 1 and slightly less than 1, respectively [34]. In the same study, the Sapphire pilot-scale, algal HTL plant operating in southern New Mexico was found to have an EROI of slightly less than 1. Our sensitivity analysis shows that, based on changes to a single parameter, Case 1 EROI could be as low as about 1.1 and as high as about 2.

Chapter 3

Economics

3.1 Analysis

3.1.1 System Design

Process economics were separated into two main systems: the HTL system and the upgrading system. The HTL system considered in this study was largely based on Case D as reported by Knorr et al. [31]. This case was chosen for its simplistic design, consideration of high-solids content feedstock (up to 36.6 wt%) and shell and tube heat exchangers. Costs were broken down by individual component, which allowed us to consider only those needed for sludge HTL.

The upgrading system was based on that reported by Jones et al. [16], which was constructed to handle algal biocrude all the way through to its constituent biofuels of gasoline, diesel and jet fuel. The components in this system are simply smaller versions of those found in a petroleum refinery. Ultimately the upgrading process would be executed at an existing petroleum refinery. For that to happen, refineries would need to be able to accept raw biocrude oil, at which point it would be assigned a market value. Economic analyses would then not need to consider on-site upgrading and would instead use the market value for untreated biocrude oil.

Cooling and storage systems were also considered in the overall process cost, similar to that reported by Jones et al. [16]. A cooling system is needed in order to bring most of the process streams back to ambient conditions. Storage is needed due to the relatively low production volume and to enable less frequent, higher capacity freight.

Full scale HTL plants from the literature have a capacity of about 1300-2000 dry tons of feedstock per day, which is achieved with 2-4 parallel reactor trains [16,31]. In this study the HTL system was sized to handle a mass flow rate on the order of 300 dry tons per day, which corresponds to the projected, maximum week flow at HBBMP in 2034 [32]. This year was chosen based on an assumed 20 year life. In order to utilize the associated literature data, these systems must be scaled down. Economic scaling is most effective at the component level since different pieces of equipment scale in different ways. These calculations are addressed in Section 3.1.2.

Special consideration was paid to the heat exchangers in the HTL system. This was due to their complicated construction, high cost and energetic importance. According to Knorr et al., the high cost is largely attributed to the size and extreme design pressure of greater than 3000 psi. Most fabricators are only ASTM-certified up to 3000 psi, and beyond that would need to be qualified for a different stamp. This creates a relatively small pool of fabricators that can complete the work, thus raising the overall cost. [31]

It was important to ensure that heat exchanger scaling remained dynamic with the rest of the model. To accomplish this heat exchangers in the system were scaled based on their exchanger surface area. According to Çengel, there are two main design paths with respect to heat exchangers: 1) select a heat exchanger with a specified temperature change in a stream of known mass flow rate, or 2) predict the outlet temperatures of a specified heat exchanger [35]. In this study we assumed an adiabatic heat exchanger and applied the first design path by specifying the temperature T_2, the heated feedstock leaving the exchanger, which is shown in Figure 3.1.

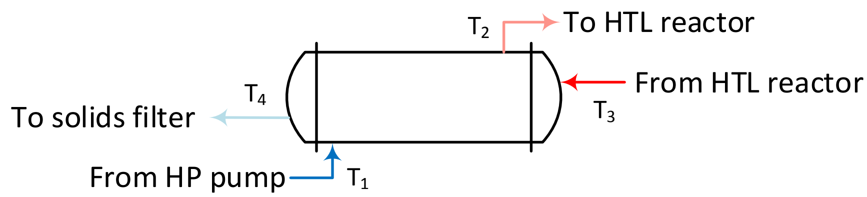

Figure 3.1: Heat exchanger nomenclature

In order to calculate heat exchanger surface area, the heat transfer rate ($\dot{Q}$), overall heat transfer coefficient (U) and temperature difference must be known. This study used the log mean temperature difference method, which is defined according to [35],

$$\dot{Q} = UA\left(\frac{\Delta T_{2,3} - \Delta T_{1,4}}{\ln\left(\frac{\Delta T_{2,3}}{\Delta T_{1,4}}\right)}\right) \tag{1}$$

The heat transfer rate was related to the mass flow rate and change in enthalpy of the fluid according to [35],

$$\dot{Q} = \dot{m}\Delta h \tag{2}$$

The overall heat transfer coefficient was thoroughly investigated by Knorr et al., and the coefficients from the appropriate case in that study were used here [31]. The base values of 170 and 154 BTU/hr/ft2/°F were used for the preheating and hot oil heat exchangers, respectively.

As discussed earlier sludge streams were assumed to mimic the thermal properties of water as they ranged from 80-99% water by mass. Thus, enthalpy values were estimated as those of water and obtained from the National Institute of Standards and Technology

(NIST) Thermophysical Properties of Fluid Systems web model at the specified temperatures and pressures [36]. Enthalpies for biocrude and upgraded biocrude were found using Aspen Plus according to their estimated molecular composition [14,16].

Case 1 was optimized for maximum production value by varying the amount of biosolids that went to the following outputs: 1) HTL, 2) Dillo Dirt, 3) contract composting and 4) land application. This optimization was performed with the Evolutionary solving method that is built in to Excel. This method was chosen for its ability to handle nonlinear and non-smooth nonlinear functions, which are embedded in the model. The optimization begins with an output distribution identical to the Base Case. Then as the mass flow rate of biosolids cake is diverted to the HTL process, mass flow rate is deducted first from land application, then from contract composting and finally from Dillo Dirt. In this way, mass is diverted in order from the most expensive to least expensive products and converted to the high-value, upgraded biocrude product.

3.1.2 Economic Calculations

In order to determine pay-back time and return on investment (ROI), yearly net cash flow (NCF) and total capital investment (TCI) must be calculated. Pay-back time is the amount of time required to earn a profit equal to that of the investment. ROI is the ratio of total project earnings to project cost, or in this case the ratio of NPV to capital cost. Once NCF and TCI were found, the NPV analysis was performed to estimate the ROI.

First, each component was scaled according to appropriate scaling variables, which included volumetric flow rate for pumps, surface area for heat exchangers and length for piping. Cost was then scaled according to [15–17,31],

$$Scaled\ equipment\ cost = Original\ cost * \left(\frac{Scaled\ capacity}{Original\ capacity}\right)^n \quad (3)$$

where n is a scaling exponent that is dependent on equipment type as summarized in Table 3.1.

Table 3.1: Equipment scaling exponents

Equipment type	Exponent	Installation Factor	Source
Piping	1	2	[31]
Solids handling equipment	0.8	2.3	[31]
Pumps/compressors	0.8	2.3	[16,31]
Heat exchangers	0.7	2.2	[31]
Pressure vessels	0.7	2	[31]
Packaged systems	0.6	1.8-2.95	[16,31]

Next, the scaled equipment cost was adjusted to the project year (PY) using the Chemical Engineering Magazine Plant Cost Index, which is similar to other TE analyses reported in the literature [15–17,31,37]. Quotes and vendor estimates were reported across varying years, so this adjustment allows for costs to be compared for the same PY. The PY is assumed to be 2014 as that is the most recent year that index numbers were available. This adjustment was made according to [15–17,31].

$$Cost\ in\ PY = Cost\ in\ quote\ year * \left(\frac{PY\ index}{Quote\ year\ index}\right) \quad (4)$$

Next, an installation factor was applied, which varied by equipment type and material (Table 3.1). Finally, Table 3.2 shows the breakdown of the total project costs. The sum of the scaled and adjusted, installed component costs is the total installed cost (TIC). Total direct cost (TDC) is then the sum of TIC and additional direct costs which included buildings and additional piping. Indirect costs are also considered and calculated as varying percentages of TDC, which included costs such as construction fees and permits.

Fixed capital investment (FCI) is the sum of TDC and indirect costs. Finally, total capital investment is the sum of FCI and working capital which can be written as,

$$TCI = [(TIC + Direct\ costs)_{TDC} + Indirect\ costs]_{FCI} + Working\ capital \quad (5)$$

Table 3.2: Total project cost assumptions

Direct Costs	[% TIC]	Source
Total installed cost	100	
Buildings	1	[15][a]
Site Development	1	[17][a]
Additional Piping	5	[17][a]
Indirect costs	[% TDC]	
Prorated expenses	10	[15,17]
Construction fee	5	[17][a]
Field expenses	10	[15]
Project contingency	10	[15][a]
Startup & permits	5	[17][a]
Other	[% FCI]	
Working capital	5	[15,17]

[a]Modified slightly from source due to existing infrastructure, available land at HBBMP and new technology uncertainty

Fixed and variable operating costs were calculated in order to realize yearly NCFs. Fixed operating costs included additional employee salaries, benefits and equipment maintenance and insurance budget. For the HTL system, benefits and overhead are assumed to be 90% of salary, while maintenance and insurance are assumed to be 2% and 0.7% of FCI respectively. [15,17]

Table 3.3 reports variable operating costs which include all inputs and outputs required for daily plant operation. These costs can be highly variable depending on current market prices, especially in the case of crude oil price [38]. Thus variable costs were assumed to be static across time due to lack of data and market uncertainty. This assumption was applied to both Case 1 and the Base Case.

Table 3.3: Variable operating cost assumptions

Material	Assumed Value		Year	Source
Land application of biosolids	32.90	$/cu yd biosolids	2014	[21][a]
Contract composting	25	$/cu yd biosolids	2014	[21][a]
Dillo Dirt	15.37	$/cu yd biosolids	2014	[21][a]
Upgraded biocrude product	100	$/bbl	2013	[38]
Hydrogen, delivered	6	$/kg	2014	[39]
Grid connection fees	65	$/account/month	2014	[23]
Grid net-metering	0.037	$/kWh	2014	[23]
Dewatering polymer	0.84	$/lb	2014	[21]
Landfill fees	32.60	$/ton yard waste	2012	[26]
Upgrading catalyst	7.75	$/lb-yr	2007	[16]

[a]Capital and fixed costs factored in to this amount

The net present value analysis was performed using the assumptions summarized in Table 3.4. In this study it was assumed that the project was built immediately (zero construction time) and that the total project cost was paid in full. These assumptions simplify the need to consider delayed start-up production and interest on debt financing, which were beyond the scope of this study.

Table 3.4: Net present value analysis parameters

Parameter	Assumed value	Source
Plant life	20 years	[15]
Discount rate	10%	[15]
Depreciation	7-year MACRS	[15,16,40]
Income tax	35%	[16,17]

First, incoming sludge flow projections were used to estimate and extrapolate NCFs through 2034 [32]. Sludge flows were iterated through the model, which produced an array of variable and fixed costs for each year. Next, the assumed tax rate was applied and tax credits from depreciation were added in. Finally the discount rate was applied to each year and all years were summed. The NPV of Case 1 was then calculated by subtracting the initial investment cost, which is summarized by,

$$NPV_{Case\ 1} = \sum_{i=1}^{final\ year} \left[\frac{NCF * (1-t) + tD_i C_0}{(1+d)^i} \right] - C_0 \tag{6}$$

where d is the discount rate, t is the federal tax rate, D is the depreciation rate, C_0 is the total capital investment and i is number of years after the project year.

Discount rate can be thought of as the inverse of compound interest as it represents the present value of future money. The discount rate chosen for this study was somewhat high to account for variation and uncertainty in the variable and fixed costs. Aden et al. also justifies this discount rate as being appropriate for renewable energy investments as determined in a previous study [15].

In order to obtain overall savings, the Base Case was integrated into Equation (6) using the same assumptions and methods as Case 1. Depreciation and capital costs for the Base Case were assumed to be built into the variable costs as reported in Table3.3. Taxes were not taken into account due to the negative yearly NCF. In comparing Case 1 to the Base Case we get the overall NPV,

$$NPV = \sum_{i=1}^{final\ year} \left[\frac{(NCF * (1-t) + tD_i C_0)_{Case\ 1,i} - (NCF)_{Base\ Case,i}}{(1+d)^i} \right] - C_0 \tag{7}$$

ROI was calculated as,

$$ROI = \frac{NPV}{TCI} \tag{8}$$

Pay-back time was calculated by finding the year in which the NPV became positive. Linear interpolation was then used to estimate the pay-back day in that year in order to report a higher resolution result.

3.2 Results & Discussion

Table 3.5 reports an estimated total capital investment for the HTL add-on system to be about \$19 M in the assumed project year of 2014. About \$12 M, or 64% of the TCI, was attributed to the purchase and installation of the equipment, or the TIC. HTL components accounted for the majority of the TIC at about \$8.2 M, or 67%. In particular, the preheating heat exchanger was the most costly component at \$3.6 M, accounting for about 43% of the total HTL equipment cost. Complete economic results tables can be found in Appendix C.

Table 3.5: Summary of total project cost

Area	Cost [2014$]
Total direct costs (TDC)	13,100,400
Total indirect costs	5,240,160
Fixed capital investment (FCI)	18,340,560
Total capital investment (TCI)	19,257,588

The plant was sized for the projected, maximum week flow in the final year of the planned system life, as described in Section 3.1.1. This flow of 310 dtpd is almost twice that of the projected yearly average flow of 159 dtpd in the same year. Alternate storage and feeding mechanisms between belt press output and HTL input could mitigate the effects of these rare peak flows. These alternate strategies could significantly lower the total project cost by reducing system size.

Despite its high design capacity, the HTL and upgrading system considered in this study was much smaller than systems considered in the corresponding literature. Component size ratios varied from 1-45% with a median size ratio of 1.4%, which shows that most components were scaled down significantly. It is not explicitly stated in the literature at what limit the scaled equipment cost assumption begins to break down. However, we expect that at this low extreme there exists significant uncertainty in the results. Overall, this indicates that further study should consider requesting new quotes for components at this smaller scale.

Table 3.6 reports the economic results of Case 1 over the 20 year project life. Return on investment of the project was calculated to be about 1.7 with a pay-back time of about 4.4 years. Savings for the CoA was estimated to be on the order of $32 M. These values are considered to be very conservative based on the scaling uncertainty described earlier in this section. Uncertainty with regard to installation and cost of an untested technology on this scale further contribute to potential over-estimation of the project cost.

Table 3.6: Case 1 lifetime economics

Parameter	Value
NPV [2014$]	32,165,447
Pay-back time [yr]	4.35
ROI	1.67

Figure 3.2 shows a graphical representation of how the NPV of the project changes across its lifetime. Pay-back time is clearly shown where the curve crosses the x-axis. The highest rate of economic gain is represented by the steepest positive slope of the curve. This occurs at the beginning of the project life when the depreciation is minimizing the

federal tax burden. The curve levels off towards the end of the project due to the increasing uncertainty in the present value of future money in those years. However, the curve does not completely level off, which suggests that there could be additional profit made from extending the life of the project.

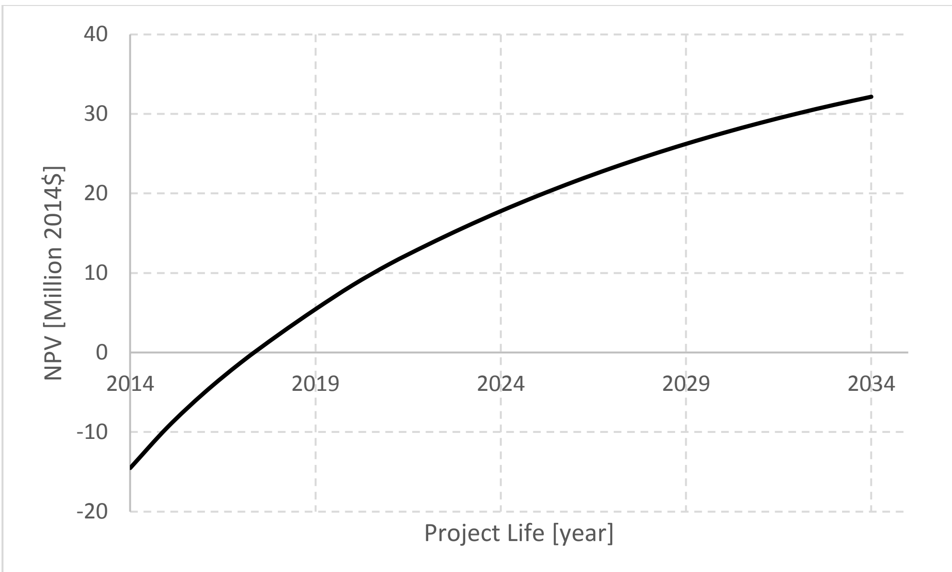

Figure 3.2: Variation of NPV across the life of the project

The 20 year plant life assumption is conservative. Literature values for plant life ranged from 20-30 years [15–17]. Originally the study was planned to match the HTL plant life to that of HBBMP, however HBBMP does not have a set lifetime. Instead processes and equipment are occasionally updated and retrofitted as components break down, show signs of wear or technologies are updated. Thus, while these initial calculations were based on a 20 year life, it is expected that the actual life of the plant would be much longer. This becomes especially true as the technology matures and more full-scale HTL plants are installed. These insights will only cause ROI to increase.

Finally, in this initial study of a proposed HTL plant it was necessary to consider on-site upgrading in order to assign an accurate price to the final upgraded biocrude product. In practice existing petroleum refineries already contain the needed infrastructure to perform upgrading at a favorable economy of scale. Leveraging this infrastructure would decrease the capital, fixed and variable costs of the HTL system proposed here. Future studies should consider collaboration with a petroleum refining company to explore the costs involved with blending or processing biocrude on a significantly large scale.

3.3 Sensitivity

Figure 3.3 reports that ROI was most sensitive to the total installed cost (TIC). This directly concerns the system sizing as discussed in Section 3.2. The TIC value of $21.3 M is calculated from the sizing assumption of maximum day flow in 2034. This is the largest flow that the HTL and upgrading system could be reasonably sized for and results in an ROI of 0.65. Alternatively, the TIC could be as low as $7.7 M if the system were sized for the average yearly flow in 2034. This results in an ROI of 3.07, but would cause the system to possibly become overloaded in its final year or even earlier. An alternative storage and feeding system to mitigate peak flows, as discussed in Section 3.2, could reduce uncertainty in component scaling and significantly increase ROI.

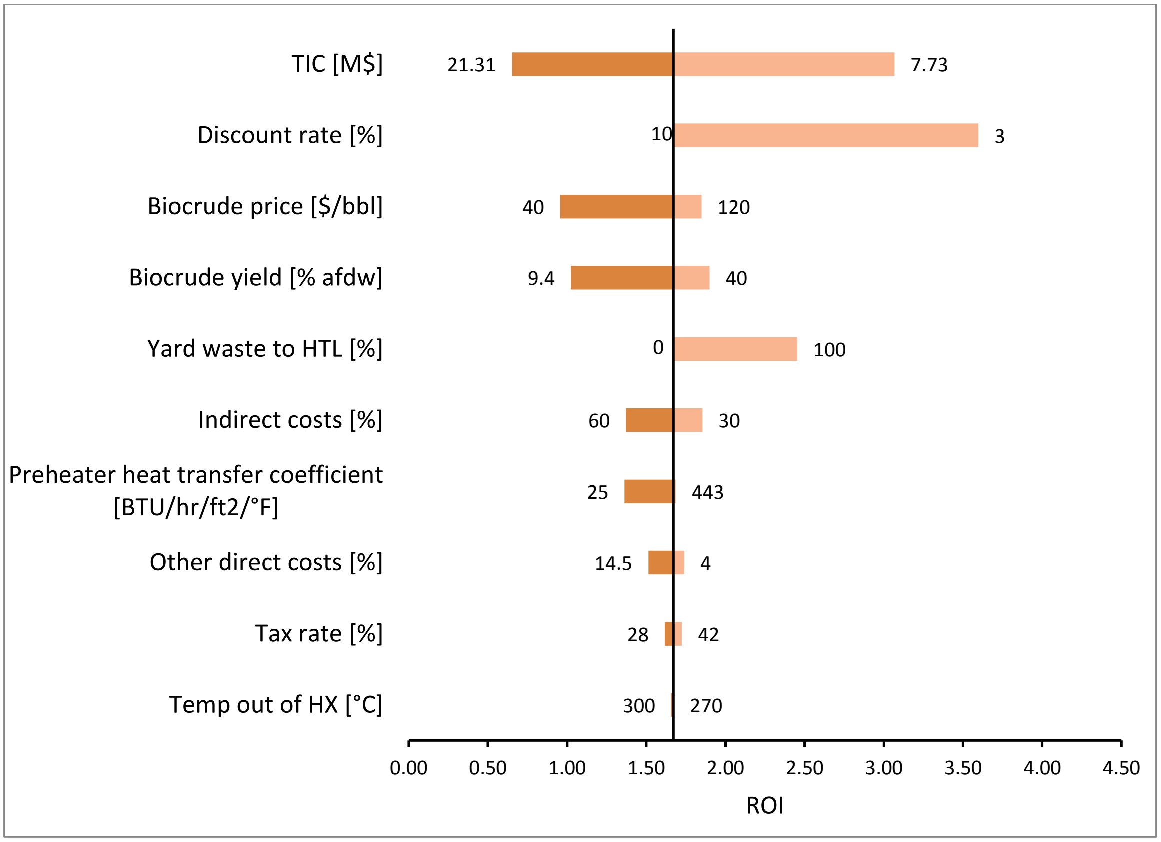

Figure 3.3: Sensitivity of chosen parameters with regards to ROI

The discount rate has the greatest potential to increase ROI based on the change of a single parameter. The value of 10% used in this study took into account the uncertainties related to establishing a new technology. Previous TE studies had used this value with respect to renewable energy projects in general. This analysis showed that decreasing the discount rate to a value closer to that of typical depreciation in the US would significantly increase the ROI to about 3.6. As the technology becomes mature, and more plants are constructed, this shift is expected to happen naturally.

Biocrude price is the third most sensitive parameter with regards to ROI. It has the potential to lower ROI significantly, but is expected to be in an almost constant state of fluctuation as it follows the current market value. At a price of $40/bbl the resulting ROI is 0.96. Oil prices have been generally increasing since the late 1990s, with some major increases and decreases leading to the present [41]. Thus, it is expected that over the 20 year life of the project that oil prices should not have a large negative effect on ROI. Additionally, future federal policy could help in this regard if biocrude were to be considered a renewable fuel, and thus be eligible for federal incentives that could protect HTL projects from large fluctuations in crude oil pricing.

Yard waste to HTL is an idea that is discussed thoroughly in Section 6.2. In this analysis the values range from 0% of yard waste included in the HTL stream, which is the value used in Case 1, to 100% of yard waste to HTL. At 100% yard waste to HTL, all landfilling costs are mitigated and biocrude production increases from the additional biomass. Added costs associated with additional required infrastructure were not considered, but are expected to be minimal in comparison with the economic gain.

A two-factor sensitivity analysis was also performed with regards to ROI. This analysis allowed for a better realization of potential gains in ROI. Parameter combinations were sorted according to greatest ROI impacts. The top six combinations are reported in Figure 3.4.

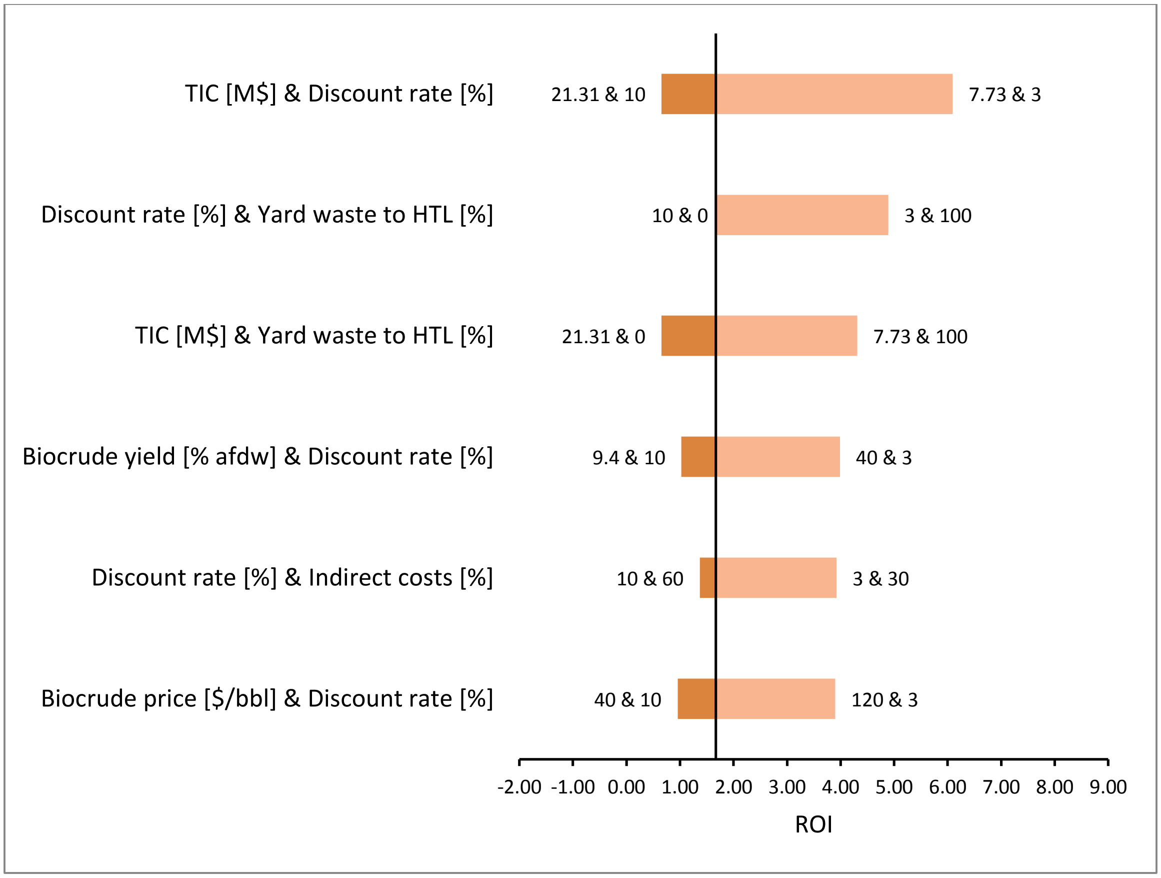

Figure 3.4: Two-factor sensitivity analysis results for ROI. The top six combinations are reported in order of greatest increase in ROI.

This two-factor analysis shows that combining a smaller system size with a less uncertain discount factor could produce an ROI of around 6. Combinations that include yard waste to HTL are expected to have a slightly lower ROI than reported due to a possible minor increase in capital cost. Overall these six different combinations show an ROI around or in excess of 4. This is especially reasonable since parameters like TIC and discount rate should decrease as the technology is implemented across increasing numbers of projects. Alternatively, if the TIC hits its maximum at the same time that biocrude price or biocrude yield hit their minimum, the ROI can drop as low as 0.24 or 0.28 respectively.

3.4 CONCLUSION

This chapter showed that economic impacts of a sludge HTL project have the potential to be favorable. It was shown that in the case of local implementation at HBBMP that this project could save the CoA on the order of $32 M. This estimate is thought to be conservative by the authors, which is further suggested by the sensitivity analysis. The two-factor sensitivity analysis reported a maximum ROI of around 6 when considering the simultaneous, best case scenario for TIC and discount rate. Both of these parameters are expected to move towards their best case scenario as more plants are built and the technology matures, thus greatly increasing ROI.

Chapter 4

Greenhouse Gas Emissions

4.1 Analysis

This study analyzed the impacts on GHG emissions, as a result of implementing Case 1, in the following three ways: 1) Case 1 sludge-to-gasoline production versus standard petroleum-to-gasoline (P2G) production, 2) sludge mitigation via Case 1 versus the Base Case and 3) Case 1 sludge-to-gasoline versus the total business-as-usual (BAU) scenario. Table 4.1, at the end of this section, presents a summary of the operational parameters used for these analyses.

Figure 4.1 presents a graphical representation of the BAU scenario. The boundaries between biosolids production and petroleum fuel production do not overlap, thus the emissions produced by both sectors are additive. GHG baseline factors were modeled in MS Excel 2013 using literature data and tools available online, including the GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation) and NETL (National Energy Technology Laboratory) models [42,43].

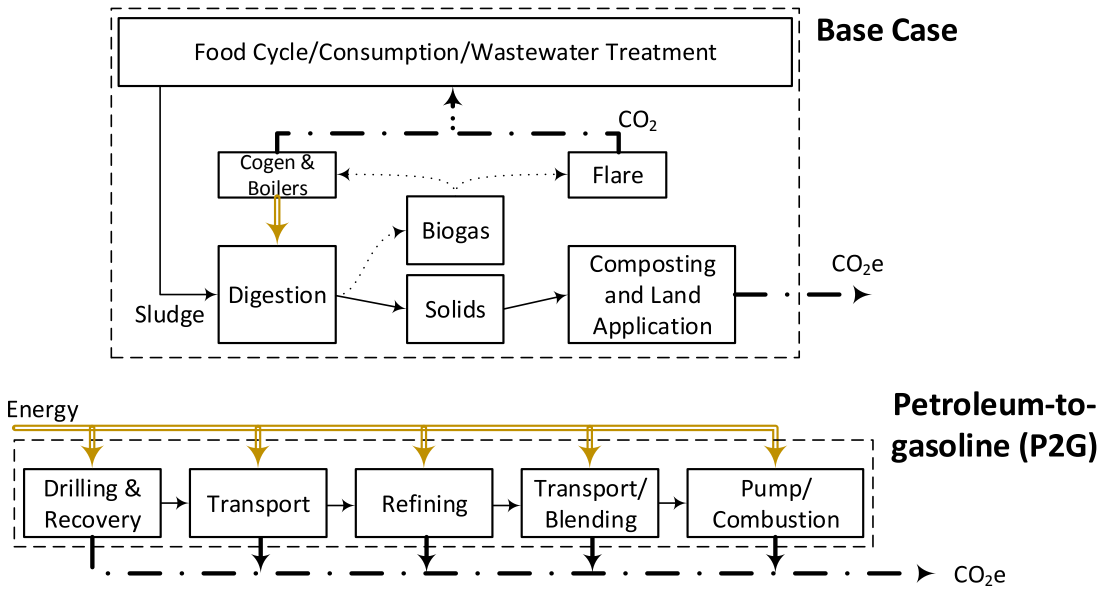

Figure 4.1: GHG emissions boundaries with respect to business-as-usual. Biosolids and petroleum fuel production do not affect one another, but both generate GHGs.

Figure 4.2 shows how Case 1 caused the BAU systems from Figure 4.1 to couple. Biocrude production and HTL processing effectively replace both petroleum exploration and extraction, as well as composting and land application of biosolids, but add emissions due to hydrogen use and previously-deferred fertilizer production. Emissions from fertilizer production were calculated assuming that fields using biosolids as a source of nitrogen would require the same amount of nitrogen from an alternate source. These emissions were calculated using GREET and assumed that the nitrogen fertilizer was synthesized from ammonia [42]. Emissions related to the production of additional hydrogen for the upgrading process were considered using GREET and assuming the hydrogen was synthesized from North American natural gas [42].

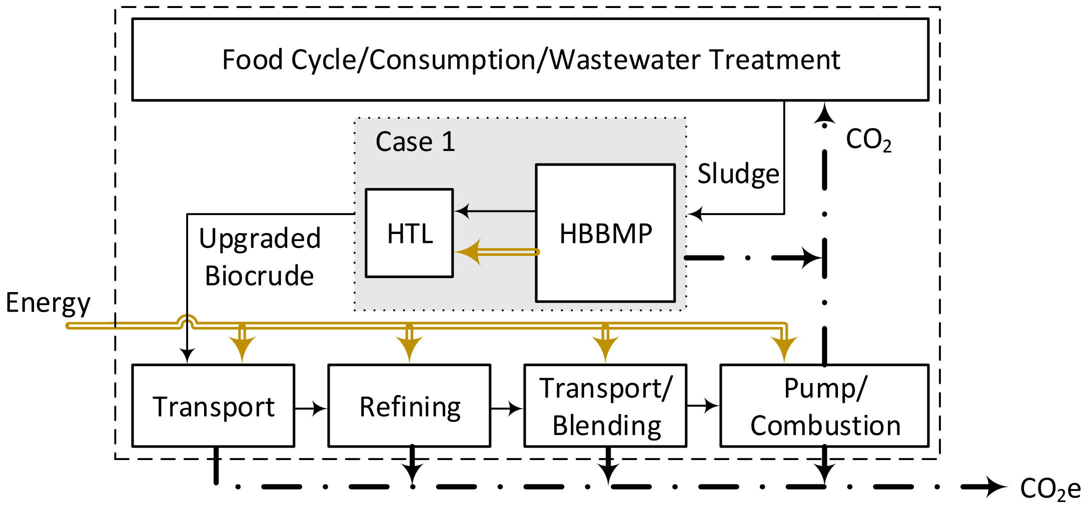

Figure 4.2: GHG emissions boundary for inclusion of the HTL system. The biosolids and petroleum fuel systems become linked.

Analysis 1 compared the Case 1 sludge-to-gasoline pathway to the P2G pathway, which considered the full, traditional gasoline production pathway from exploration and drilling to combustion (Figure 4.1). This comparison allows decision-makers to understand how Case 1 would affect GHG emissions in terms of renewable fuel policies such as EISA. Life cycle analyses and emissions characterization for petroleum-derived fuels are relatively common and report varying results. Thus, averages from multiple literature sources were used for each data point [42–46]. This study focused on emissions as a result of gasoline production as they are generally the highest as compared to diesel and jet fuel [42,43]. The functional unit was 1 MJ of product energy, which is the standard metric for fuel-based GHG emissions analyses.

Analysis 2 compared Case 1 to the Base Case in terms of GHG emissions produced in the process of converting sludge to a safe, useful product. For the Base Case this was the production of biosolids and compost, and for Case 1 this was the production of biocrude oil. The system boundary in Analysis 2 ends at the point where the upgraded biocrude oil is transported off-site. The functional unit used for Analysis 2 was 1 dry kg of incoming sludge. This was due to the two cases having an identical input. This analysis is important because it shows how Case 1 affects GHG emissions locally.

Finally, Analysis 3 compared the Case 1 sludge-to-gasoline scenario to the BAU scenario. The comparison was made on a total CO_2-equivalent (CO_2e) per year basis in order to see overall impact. This analysis was important because implementation of Case 1 affects both the biosolids manufacturing and petroleum industries simultaneously.

In the Base Case energy requirements are fulfilled on-site from biogas capture and utilization. Excess biogas is flared in order to mitigate methane (CH_4) emissions, which are about 25 times more environmentally impactful than CO_2 over a 100 year period [43]. Carbon emissions from the combustion of biogas were excluded from calculations in accordance with international convention set forth by the Intergovernmental Panel on Climate Change (IPCC) [47]. This convention states that the carbon released from the combustion of biomass and its products is assumed to be balanced with the carbon uptake from the biomass while it was growing. In this analysis the sludge that enters HBBMP was assumed to be composed entirely of biomass produced from the food cycle. This exclusion is limited to CO_2 only, as other GHGs such as CH_4 and nitrous oxide (N_2O) will not be reabsorbed into the cycle.

The City of Austin (CoA) reported that biogas combustion was considered a carbon-neutral alternative source to grid electricity and natural gas use. In addition to the zero emissions from biogas combustion, additional credits were applied for offsetting grid and natural gas energy [32]. It is the opinion of the authors that the additional credits are considered double counting. In this study credit was given only to electricity generated from biogas combustion that was supplied to the grid in excess of what was used on-site. If excess biogas was contributed to natural gas infrastructure a credit would be appropriate there as well, but currently this is not the case.

Operational emissions at HBBMP come from the use of diesel fuel on-site and the off-site production of chemicals required for composting and dewatering. Diesel fuel is used in vehicles that manage composting, transport biosolids for land application and apply biosolids to the grass fields on-site. Embedded energy and emissions of the existing infrastructure were not considered.

Table 4.1: Model parameters and assumptions used in GHG analysis

Parameter	Assumed Value		Source
Conventional gasoline LHV	44	MJ/kg	[43]
Conventional gasoline density	2.8	kg/gal	[43]
Diesel LHV	42	MJ/kg	[42]
Diesel GHG	76.7	kg CO_2e/mmBTU	[43]
Nitrogen fertilizer production	3.3	kg CO_2e/kg N	[42]
Hydrogen production (from natural gas)	18.4	kg CO_2e/kg H_2	[42]
Emissions from electricity (ERCOT mix)	616	g/kWh	[42]
Industrial natural gas emissions	54.7	kg CO_2e/mmBTU	[48]
Nitrogen content in biosolids cake	3.9	%	[29]
Distance to refinery	150	mi	
Crude tanker truck capacity	210	bbl/load	
Crude tanker truck fuel economy	6.5	mi/gal	

4.2 Results & Discussion

Figure 4.3 reports that GHG emissions were reduced in the P2G scenario by about 30 gCO_2e/MJ, or 33%. The majority of emissions from standard gasoline production occur at the tailpipe. Nearly all of those emissions were removed in Case 1 due to the organic nature of the feedstock. Only non-CO_2 GHG emissions were counted, which were almost negligible at less than 1 gCO_2e/MJ. Emissions due to production increased by about 16 gCO_2e/MJ from the P2G scenario to Case 1. This was due to consideration of on-site hydrogen use in the upgrading system. Typically these emissions would occur at the refinery, and thus be counted in the refinery emissions profile. Since Case 1 considered both on-site upgrading and refinement in a traditional refinery, it could be possible that the hydrogen use was being double-counted. Higher resolution data of refinery emissions would help to solve this and could further reduce the Case 1 GHG emissions.

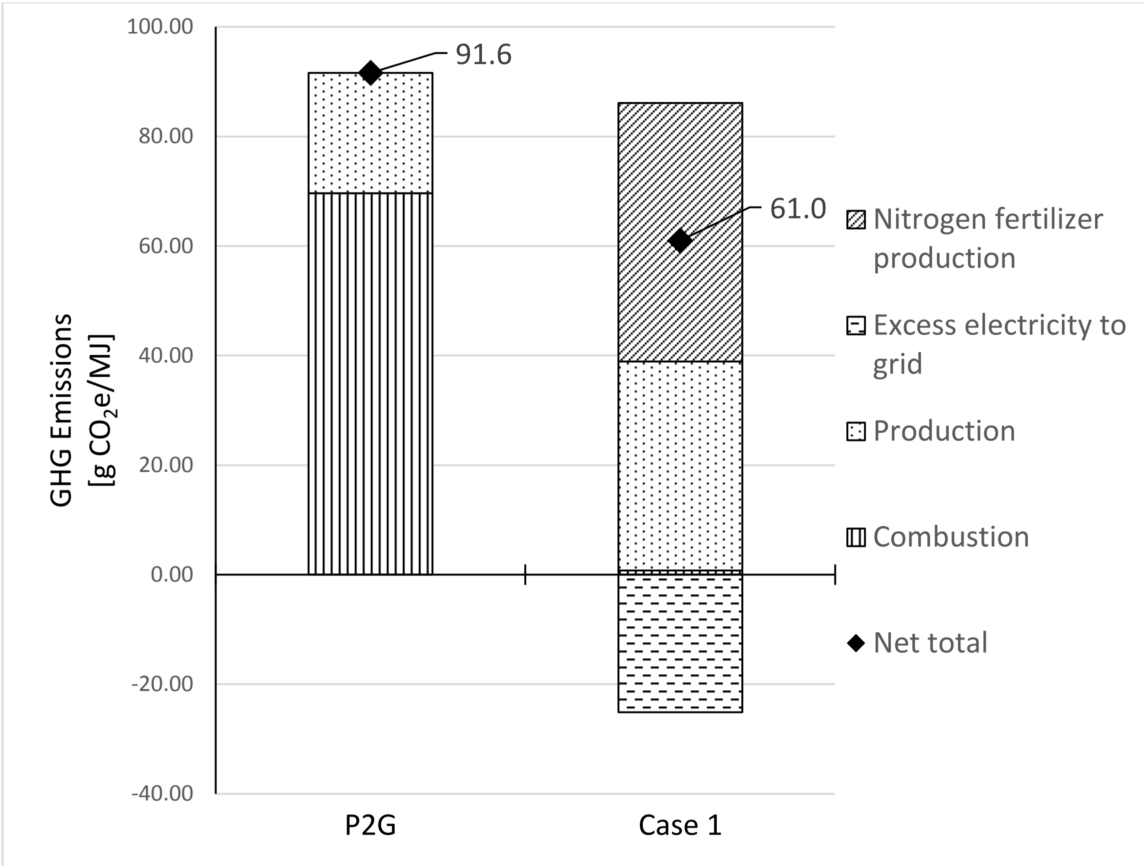

Figure 4.3: Comparison of GHG emissions per MJ of energy for gasoline production via standard P2G and Case 1

Emission reduction in Case 1 came from credit given for excess electricity contributed to the grid, as explained in Section 4.1. This power contribution directly offset emissions that would have been generated according to the standard ERCOT fuel mix.

Figure 4.4 reports that GHG emissions were increased in the sludge mitigation scenario by about 45 gCO_2e/kg sludge, or 187%. The majority of GHG emissions from Case 1, 71.6 gCO_2e/kg sludge, were attributed to external nitrogen fertilizer production, which is typically deferred by land application of biosolids and composting. This is assuming that the fields typically utilizing biosolids for nitrogen would need to completely replace that nitrogen with an alternate source, as explained in Section 4.1. Alternatively, in the absence of available biosolids, less nitrogen could be applied to the fields. It may also be acceptable for the fields to produce less. If either of these cases are true then emissions would be greatly reduced. Additionally, hydrogen use was a large contributor with almost 34 gCO_2e/kg sludge.

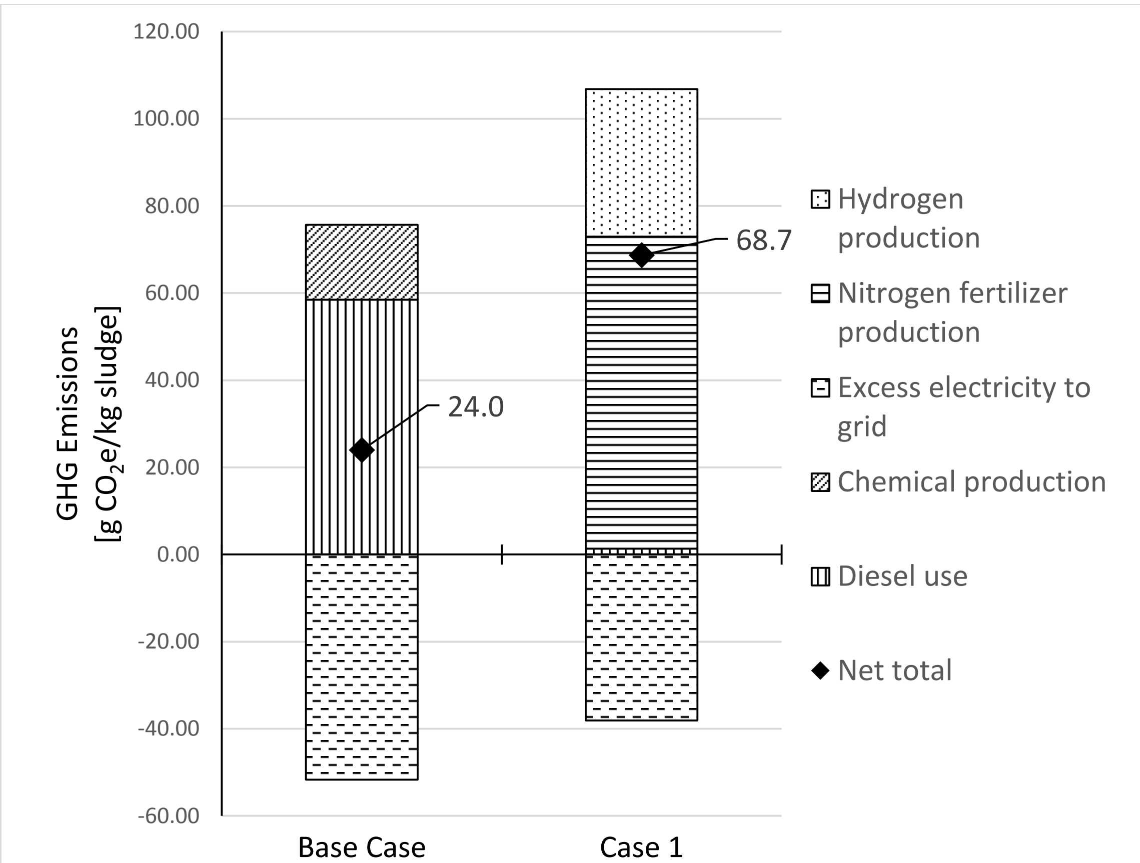

Figure 4.4: Comparison of GHG emissions per kg of incoming sludge between the Base Case and Case 1

The majority of GHG emissions generated in the Base Case, about 59 gCO_2e/kg sludge, came from on-site diesel fuel usage. Diesel is mostly used for the composting operations and to transport biosolids for land application. The rest is attributed to the production of chemicals used in the biosolids and composting processes. Figure 4.4 shows that the diesel and chemical use in the Base Case were almost completely mitigated in Case 1 due to removal of the composting operation.

Figure 4.5 shows that overall, Case 1 reduced GHG emissions by about 44% as compared to the uncoupled BAU scenario. For the P2G scenario, the model predicted a savings of about 1500 MT CO_2e/y over traditional gasoline production. With respect to the impacts at HBBMP, the model reported an increase of about 1460 MT CO_2e/y. The overall savings comes from the BAU case being additive, while additional Case 1 emissions incurred from conversion of biocrude to gasoline are small.

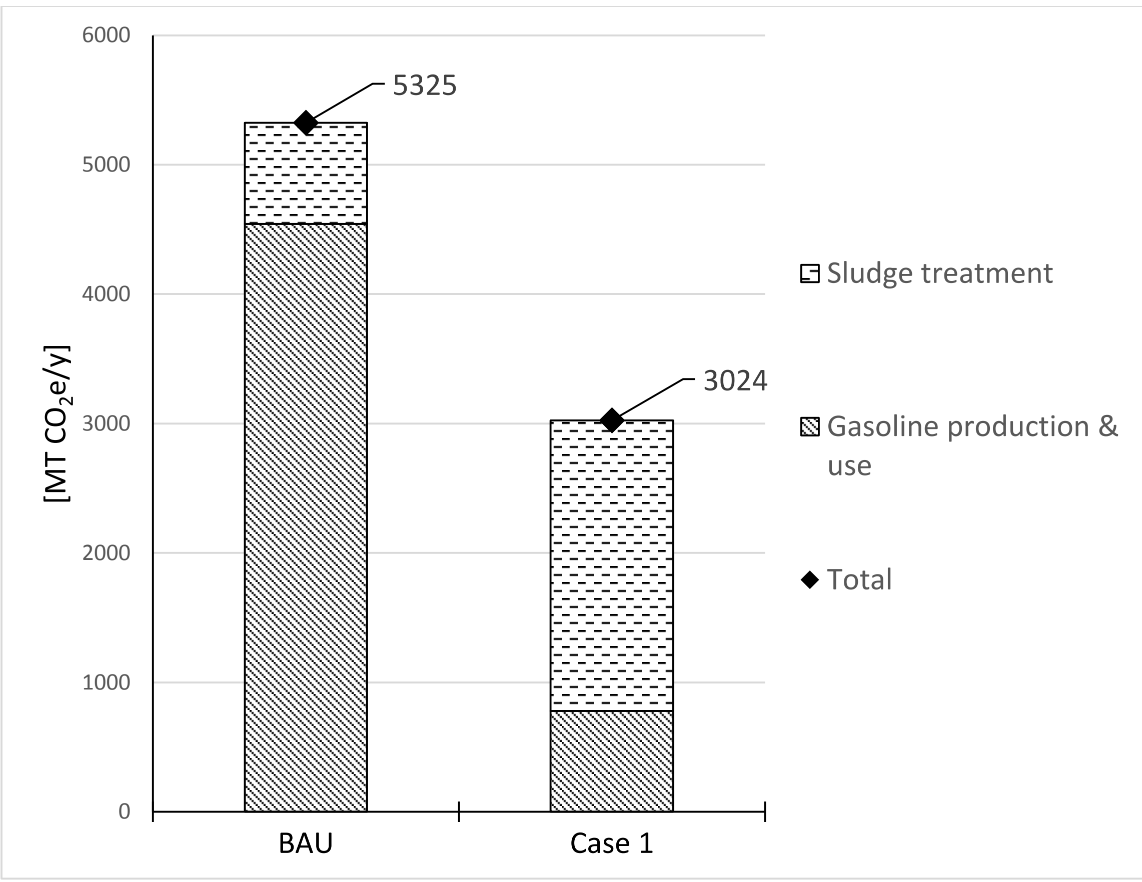

Figure 4.5: Total GHG emissions per year for BAU vs. Case 1. Despite an increase in sludge treatment emissions at HBBMP, overall GHG emissions are reduced by about 40%.

4.3 Sensitivity

Figure 4.6 reports the sensitivity of emissions parameters with respect to the P2G scenario. This figure indicates which parameters are capable of altering the sludge HTL-derived gasoline qualifications under RFS2 standards. To be considered a renewable fuel there must be a 20% reduction in GHG emissions over the standard P2G baseline. A 50% reduction qualifies the fuel as an advanced biofuel.

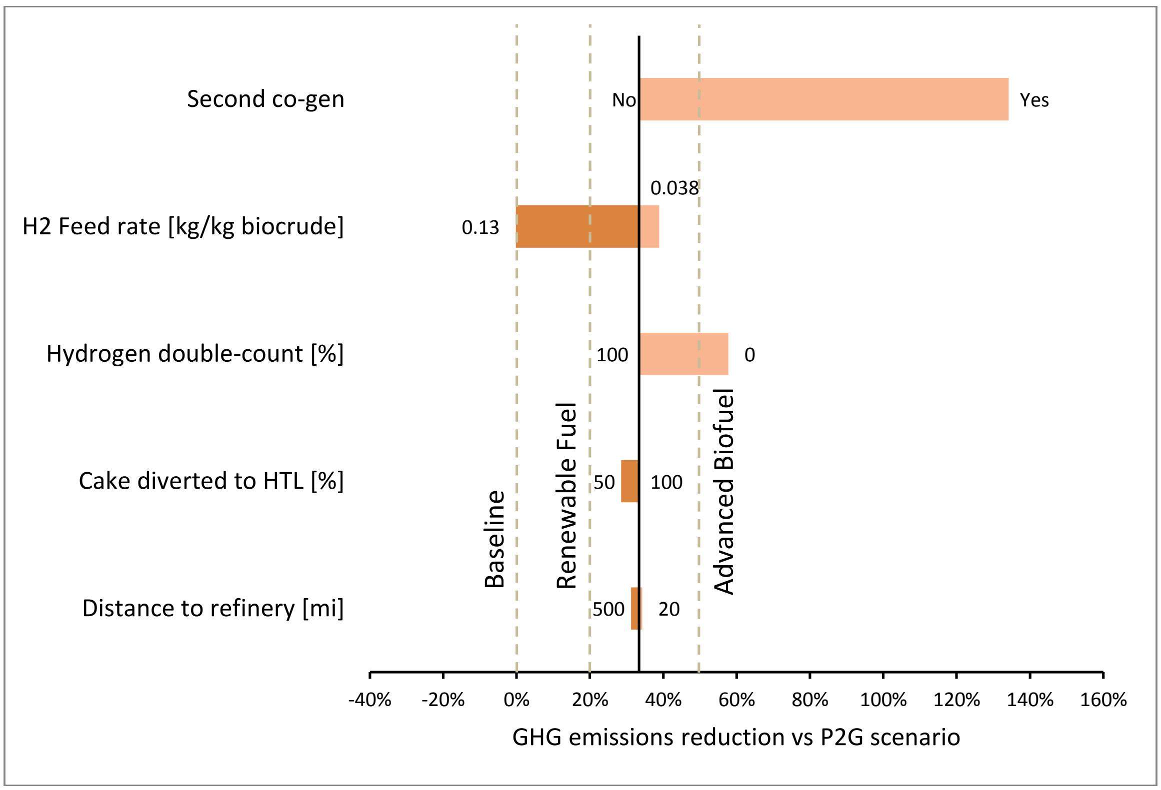

Figure 4.6: Sensitivity of selected parameters with regards to reduction in GHG emissions of Case 1 compared to the P2G scenario. EISA RFS2 category limits are shown by the gray dashed lines.

The greatest reductions to GHG emissions are gained through the “What-If” scenarios proposed in this analysis. The first of which was the addition of a second co-gen unit, which results in a 134% reduction. A reduction of this magnitude would result in Case 1 producing negative net emissions. This would be achieved by offsetting more GHGs from the ERCOT power mix than are produced from making and combusting the fuel. This scenario would affect ROI in a negative way, but could be very beneficial if ROI is already high. A similar scenario would involve contributing excess biogas to a gas distribution line.

Hydrogen double-counting was considered as a possibility in Section 4.1. In this analysis the effect of mitigating this possibility is reported. Figure 4.6 shows that in the case of complete hydrogen double-counting there would be a 60% reduction in GHG emissions. This alone would qualify the sludge HTL-derived gasoline as an advanced biofuel which may cause additional government funding to become available. It is most likely that only some percentage of the hydrogen was double-counted in Case 1, so it is expected that overall GHG emissions reduction would be between the reported 33% and the possible 60% seen in Figure 4.6.

4.4 Conclusion

This chapter showed that eligibility of sludge HTL-derived gasoline as a renewable fuel is attainable and likely. Two major assumptions in these analyses caused a significant amount of uncertainty in the results. The first was the assumption that fields currently using biosolids fertilizer required a fixed amount of nitrogen. This meant that all biosolids diverted from land application to HTL would cause an increase in external nitrogen fertilizer production, which greatly increased overall emissions. The second assumption was that hydrogen use for biocrude upgrading was not included in the refinery data, thus needing to be included with the on-site calculations. The impacts of this assumption were further investigated using sensitivity analysis in Section 4.3.

Overall, GHG emissions would be reduced by implementation of the sludge HTL technology, but the magnitude of this impact is uncertain. If farms were able to reduce their nitrogen requirements or additional steps were taken to recover nitrogen from other HTL products, GHG emissions could be further reduced. Furthermore, GHG emissions could be reduced if biocrude upgrading were performed at the refinery instead of on-site. Finally, a major barrier is the amount of mass produced. At this magnitude of fuel production, total emission reduction is minimal.

Chapter 5

Broader Impacts

The EPA estimates biosolids production to be in excess of 8 million dry tons per year in the US. This estimate was inserted into the model in order to evaluate potential impacts of nation-wide implementation of the technology. Table 5.1 reports approximately 4.5 million barrels of upgraded biocrude production per year. From this, about 90 million gallons of gasoline could be produced, which would offset about 332,000 MT CO_2e annually. That would be the equivalent of taking 70,000 passenger vehicles off of the road.

Table 5.1: Impacts of nation-wide implementation of biosolids HTL

Parameter	Value
Upgraded biocrude production [bbl/y]	4,480,074
Gasoline [gal/y]	89,601,477
Diesel [gal/y]	44,800,738
Jet Fuel [gal/y]	17,920,295
Offset emissions from gasoline [MT CO_2e/y]	332,102

The 33% reduction in GHG emissions over standard lifecycle gasoline production qualifies Case 1-produced gasoline as a renewable fuel under the RFS2. This could enable HTL projects to be eligible for government grants, loan guarantees and/or tax credits, all of which would increase project ROI.

The major barrier of fuel production from sludge is the lack of feedstock mass, which becomes apparent in this chapter. According to the EIA, the US consumed almost 140 billion gallons of gasoline in 2014 [49]. The roughly 90 million gallons of HTL-derived gasoline, that could be produced if all biosolids production in the US was processed via HTL, would then contribute about 0.07% of total gasoline consumption. The RFS2 mandates that 36 billion gallons of gasoline equivalent come from renewable fuels by 2022, of which HTL could contribute about 0.25%.

In order to make a significant impact on fuel production, alternative feedstocks should be considered. Farm animal manure is produced in the US at an estimated rate of about 250 million dry tons per year and is considered in several HTL studies [3–5,50]. Our model predicts that a feedstock of this magnitude could result in about 2.8 billion gallons of gasoline per year, or 8% of the total RFS2 mandate in 2022, and a reduction of 10.5 million MT CO_2e or the equivalent of 2.2 million passenger vehicles.

Chapter 6

Conclusion & Recommendations

6.1 Summary

HTL is a novel and versatile mitigation option for sludge and biosolids, and could be very attractive economically. The conservative estimate calculated in this study showed savings of about $32 million over the 20 year life of the project. This is significant for a semi-mandatory facility that typically operates at an economic loss.

Contributions as a renewable fuel source are minimal due to limited feedstock. GHG emissions were reduced, but impact at this scale was relatively low. However, sensitivity analysis showed that adding an additional co-gen unit could cause the process to produce fuel at net negative emissions. Consideration of farm animal manure as a feedstock for a biosolids HTL plant could 1) significantly increase national impact as a fuel source and 2) offset a significant amount of GHG emissions.

6.2 Recommendations for Future Research

There are numerous engineering details that should be addressed in future studies in order to generate more accurate TE analyses for sludge HTL. In terms of project economics, future studies should consider the following: 1) Obtain quotes from vendors on components that are closer to the required size will minimize scaling uncertainties as discussed in Section 3.2. 2) Investigate methods for transferring or storing the biosolids from the end of the biosolids process to the HTL system that would accommodate extreme flow rate fluctuations. 3) Consider process downtime. TE analyses from the literature tend to assume a certain amount of “stream days” per year to account for downtime [16,17]. However, HBBMP has recursive parallel systems so that if a component breaks down, the flow can shift to a parallel track and continue to run continuously. This same parallel process design should be investigated and optimized for the HTL system so that the process would operate continuously along with HBBMP.

In this study the HTL process was optimized for daily production value, which ultimately corresponded to maximizing fuel production. Future studies may want to optimize operations in other ways such as minimizing GHG emissions, pay-back time or maximizing ROI or EROI. The framework generated and the dynamic model implemented in this study accommodates for these future studies to be conducted.

Optimization of the HTL feedstock could also be considered. Pre-digested sludge has a higher VS content than that of biosolids cake, which would result in an increased biocrude yield. A separate case could then be modeled that extracts both pre-digested sludge, which would decrease biogas production, and biosolids cake, so that the biogas stream was fully utilized. The optimization could be based on attaining maximum EROI, economic value or biogas usage.

It was assumed that as biosolids were diverted from composting to HTL, city yard waste typically mixed with those biosolids was then diverted to the local landfill at a specified cost. In this study this cost was the largest daily cost in Case 1. This cost could be mitigating by further research in two areas: 1) multi-component HTL feedstock streams and 2) 3rd-party composting.

1) The organic nature of the yard waste should allow it to be added to the HTL input stream and processed into biocrude. Research should be done on how multi-component feedstock streams affect HTL yields and biocrude compositions and what additional equipment would be needed. Fats, oils and grease are also collected by the CoA, but are typically dewatered and landfilled or disposed of at hazardous

waste facilities [27]. These materials have very high VS content which could increase biocrude yields significantly if added to the HTL feedstock stream. Overall, multi-component feedstock streams could improve sludge HTL by 1) increasing total feedstock mass potential, 2) increasing oil yields and EROI, 3) decreasing alternative disposal costs and 4) decreasing GHG emissions related to alternative disposal methods.

2) Excess yard waste diverted to a 3rd-party composting service would still incur some cost, although possibly less than that of a landfill. It would also continue to create a benefit environmentally. Additionally, it may be appropriate to credit back some GHG emissions from external fertilizer production as some mass percentage of the compost would contain nitrogen.

Our results show that in both cases there is a large amount of excess biogas that could be used to fuel additional heat-intensive processes at the HMMBP complex. Processes considered in other works include on-site hydrogen production and catalytic hydrothermal gasification (CHG). CHG can be used to recover CH_4 and significant amounts of nitrogen from the HTL and upgrading aqueous byproducts [4,16,28]. This nitrogen source could be used to replace fertilizer requirements typically fulfilled by land application of biosolids and composting, which would drastically reduce GHG emissions associated with Case 1. However, capital cost would increase significantly. Further testing of the aqueous HTL byproducts should be performed to estimate possible impacts versus cost.

Appendices

APPENDIX A: NOMENCLATURE

AFDW	Ash-free Dry Weight
AWU	Austin Water Utility
BAU	Business-As-Usual
BBL	Standard barrel of oil
BOP	Balance of Plant
BP	Belt Press
BTU	British Thermal Units
CFR	Code of Federal Regulations
CO_2e	Carbon dioxide equivalent
CoA	City of Austin
DT	Dry (short) Ton
EISA	Energy Independence and Security Act of 2007
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EROI	Energy Return on energy Investment
FCI	Fixed Capital Investment
FEB	Flow Equalization Basin
GBT	Gravity Belt Thickener
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
HBBMP	Hornsby Bend Biosolids Management Plant
HHV	Higher Heating Value
HTL	Hydrothermal Liquefaction
IPCC	Intergovernmental Panel on Climate Change
kWe	Kilowatt electric
kWt	Kilowatt thermal
LHV	Lower Heating Value
mmcf	Million cubic feet
MGD	Million Gallons per Day
mmBTU	Million BTU
MT	Metric ton
NETL	National Energy Technology Laboratory
NIST	National Institute of Standards and Technology
P2G	Petroleum to Gasoline
PY	Project Year

ROI	Return on Investment
TDC	Total Direct Cost
TE	Techno-economic
TIC	Total Installed Cost
Ton	Short ton
VS	Volatile Solids
WWTP	Wastewater Treatment Plant

APPENDIX B: ADDITIONAL MASS & ENERGY MODEL RESULTS

Stream designators in each table included in this appendix correspond to the Case 1 process diagram located in Chapter 2 (Figure 2.2). All mass results include water content.

Table B1: Case 1 mass flow results with TS, VS and HTL temperature and pressure data.

Stream	Description	Mass [MT/d]	TS [%]		VS [% afdw]	
2	FEB out	5776	1.6		71.7	
3	GBT In	5776	1.5		72.4	
4	Digester In	1057	7.2		67.7	
5	Digester Out	1035	5.4		46.4	
6	BP In	1035	5.4		46.4	
7	BP Out	253	19.8		54.4	
8	Land App	0	-		-	
9	Compost In	0	-		-	
10	To Dillo Dirt	0	-		-	
11	To Contract	0	-		-	
			Temperature		Pressure	
			[°C]	[°F]	[MPa]	[psi]
12	Dewatered biosolids to HTL	253	21	70	0.1	14.7
13	High pressure to heat exchanger	253	22.6	73	21.0	3050
14	To HTL reactor	253	280	536	20.7	3000
15	HTL to heat exchanger	253	350	662	20.7	3000
16	HTL products out of HX to filter	253	74.6	166	20.3	2950
17	Filter out (Char)	2.72	21	70	0.1	14.7
18	HTL products - char	250	74.6	166	20.0	2900
19	Biocrude	8.16	74.6	166	10.5	1530
-	Upgrade preheat	8.16	171	339	10.5	1530
-	Hydrotreater	8.16	400	752	10.5	1530
20	Upgraded biocrude	6.85	21	70	0.1	14.7

Table B2: Case 1 heat and energy flow results

Stream	Description	Heat [GJ/d]	Power [kWh/d]
H1	Co-gen heating	97	-
H2	Additional AD heating	10	-
H3	HTL heating	106	-
H4	Upgrade heating	7	-
E1	Co-gen power	-	20352
-	Base Case power	-	12842
E6	Grid net-metering	-	5535
E7	HTL pumping	-	1859
E8	Upgrade pumping	-	116

Table B3: Case 1 gas flow results.

Stream	Description	Mass [MT/d]	Volume	
			[m^3/d]	[mmcf/d]
G1	Biogas produced	22.3	25252	0.89
G2	To Cogen	8.1	9179	0.32
G3	To Boilers	5.1	5717	0.20
G4	Flare-off	9.2	10357	0.37
G5	HTL off gas	3.5	-	-
G6	Hydrogen for upgrading	0.16	-	-
G7	H2 recycle	0.24	-	-
G8	Upgrading off-gas	0.25	-	-
G9	Total off-gas	3.8	-	-

Table B4: Water and other mass flow results

Stream	Description	Mass [MT/d]	TS [%]
W1	GBT Wash	6370	0.21
W2	BP Wash	1764	0.32
W3	Secondary In	8133	0.23
W4	To Ponds	8218	0.00
W5	HTL aqueous phase	239	0.00
W6	Upgrading aqueous phase	1.25	0.00
W7	Total aqueous phase	240	0.00
P1	Polymer prior to GBT	0.27	-
P2	Polymer prior to BP	0.47	-
YW	Yard Waste input from city	75	-

APPENDIX C: ADDITIONAL ECONOMIC MODEL RESULTS

Table C1: Results for TCI based on TIC and Table 3.2

	[2014$]
Total installed cost (TIC)	12,243,365
Other direct costs	
Buildings	122,434
Site Development	122,434
Add. Piping	612,168
Total direct costs (TDC)	13,100,400
Indirect costs	
Prorated expenses	1,310,040
Construction fee	655,020
Field expenses	1,310,040
Project contingency	1,310,040
Startup & permits	655,020
Total indirect costs	5,240,160
Fixed capital investment (FCI)	18,340,560
Working capital	917,028
Total capital investment (TCI)	19,257,588

Table C2: Variable operating cost results based on 2014 mass flow and calculated using assumptions in Table 3.3

Material	Cost [2014$/yr]	
	Base Case	Case 1
Land application of biosolids[a]	2,284,611	0
Contract composting[a]	868,013	0
Dillo Dirt[a]	533,654	0
Upgraded biocrude product	-	(2,048,193)
Hydrogen	-	360,081
Grid connection fees	7,020	7,020
Grid net-metering	(101,425)	(74,754)
Dewatering polymer	500,766	500,766
Landfill fees	0	963,612
Upgrading catalyst	-	10,168
Total	4,092,639	(281,300)

[a]Capital and fixed costs factored in to this amount

Table C3: Case 1 fixed operating costs in 2014

Employees	# of positions	Cost [2014$/yr]
Plant engineer	1	75,582
Maintenance technician	2	86,380
Total salaries		161,962
Other	Assumptions	
Benefits and gen overhead	90% total salaries	145,766
Maintenance	2% FCI	167,112
Insurance and taxes	0.7% FCI	58,489
	Total	533,330

Table C4: Full breakdown of total installed cost

Area	Equipment Name	Price [$]	Year	Scaling Variable	Equipment Flow	Scaling Flow	Units	Size Ratio	Scaling Exponent	Installation Factor	Scaled Purch Cost [$]	Purch Cost in Proj Year [$2013]	Installed Cost in Proj Year [$2013]	Ref
HTL System														
	Twin Screw Feeder	191468	2011	Pump feed	190	146	gpm	0.767	0.8	2.3	154929	152363	350435	[31]
	Biomass Feed Pump	191468	2011	Pump feed	190	146	gpm	0.767	0.8	2.3	154929	152363	350435	[31]
	Preheater	1965333	2013	Area	3000	2287	ft2	0.762	0.7	2.2	1625133	1650055	3630122	[31],[35]
	Reactor HX	998850	2013	Area	6032	1006	ft2	0.167	0.7	2.2	285071	289442	636773	[31],[16]
	Reactor pipe	272788	2013	Length	480	218	ft	0.454	1	2	123755	125652	251305	[31]
	Gas KO Drum	5600000	2012	Volume	16920	527	gal	0.031	0.7	2	493935	486669	973337	[31]
	Solids Filter	1311000	2011	Filter feed	3689	146	gpm	0.040	0.6	1.7	188685	185560	315452	[31]
	Separator	3565000	2011	Sep feed	3689	146	gpm	0.040	0.7	2	371436	365284	730569	[31]
	Hot Oil System	1200500	2012	Duty	60	13.16	MMBTU/ hr	0.219	0.6	1.8	483151	476044	856879	[31]
	Oil	1133730	2012	Slurry Mass Flow	1225235	72907	lb/hr	0.060	1	1	67462	66470	66470	[31]
											SUBTOTAL	**3,949,903**	**8,161,776**	
Upgrading System														
	Hydrotreater Reactor, vessels, columns	27000000	2007	Biocrude feed	6,524	170	bpd fd	0.026	0.75	1.51	1749534	1918027	2896221	[16]
	Hydrogen Compressor	1385600	2011	H2 feed	17.1	0.50	mmscfd H2	0.029	0.8	1.1	82612	81244	89368	[16]
	PSA for Hydrogen Recycle	1750000	2004	H2 feed	10	0.50	mmscfd H2	0.050	0.8	2.47	160265	207818	513310	[16]
											SUBTOTAL	**2,207,089**	**3,498,899**	
Cooling System														
	Cooling Tower System	2000000	2009	Circ rate	35631668	281601	lb/hr	0.008	0.6	2.95	109574	120127	354375	[16]
	Cooling water pump	445700	2009	Circ rate	35631668	281601	lb/hr	0.008	0.6	2.95	24419	26770	78973	[16]
Storage														
	Product storage - 3 day	320384	2005	Product rate	558000	21890	gal	0.039	0.65	2.95	39040	50624	149341	[16]
											SUBTOTAL	**197,522**	**582,689**	
											TOTAL INSTALLED COST (TIC)	**6,354,513**	**12,243,365**	

Table C5: Full NPV calculation

Year	Mass Flow [dtpd]	Mass Flow [kg/d]	Variable Operating Costs [$/d]	Fixed Operating Costs	Net Cash Flow [$/y]	After taxes [$]	With depreciation [$]	Present Value [2014$]	Base Case NCF [$/y]	Present Value of Base Case [2014$]	Net Savings [2014$]	Cumulative savings [2014$]	NPV [2014$]
2014	99	89530	666	533330	-290181	-290181	672988	672988	4085619	-4085619	4758607	4,758,607	-14,498,981
2015	102	92269	760	537968	-260561	-260561	1390103	1263730	4213720	-3830655	5094385	9,852,992	-9,404,596
2016	105	95008	854	542566	-230901	-230901	947952	783431	4341821	-3588282	4371713	14,224,705	-5,032,883
2017	108	97748	948	547126	-201204	-201204	640642	481324	4469921	-3358318	3839642	18,064,346	-1,193,242
2018	111	100487	1042	551649	-171470	-171470	430426	293987	4598022	-3140511	3434498	21,498,844	2,241,256
2019	114	103226	1135	556137	-141700	-141700	459522	285327	4726123	-2934550	3219877	24,718,722	5,461,134
2020	117	105965	1229	560590	-111896	-111896	490000	276592	4854223	-2740083	3016675	27,735,396	8,477,808
2021	120	108704	1323	565011	-82059	-82059	218552	112151	4982324	-2556720	2668872	30,404,268	11,146,680
2022	123	111443	1417	569400	-52191	-52191	-52191	-24347	5110425	-2384051	2359704	32,763,971	13,506,383
2023	126	114182	1511	573757	-22291	-22291	-22291	-9454	5238526	-2221646	2212193	34,976,164	15,718,576
2024	129	116922	1605	578085	7639	4965	4965	1914	5366626	-2069067	2070981	37,047,145	17,789,557
2025	132	119661	1699	582384	37597	24438	24438	8565	5494727	-1925868	1934434	38,981,579	19,723,991
2026	135	122400	1792	586655	67584	43930	43930	13997	5622828	-1791606	1805604	40,787,182	21,529,594
2027	138	125139	1886	590898	97599	63439	63439	18376	5750928	-1665839	1684215	42,471,397	23,213,809
2028	141	127878	1980	595114	127639	82966	82966	21847	5879029	-1548132	1569980	44,041,377	24,783,789
2029	144	130617	2074	599305	157706	102509	102509	24540	6007130	-1438059	1462599	45,503,976	26,246,388
2030	147	133356	2168	603470	187798	122069	122069	26566	6135230	-1335205	1361771	46,865,746	27,608,158
2031	150	136095	2262	607611	217915	141644	141644	28024	6263331	-1239167	1267190	48,132,937	28,875,349
2032	153	138835	2356	611729	248055	161236	161236	29000	6391432	-1149555	1178555	49,311,492	30,053,903
2033	156	141574	2449	615822	278218	180842	180842	29569	6519532	-1065996	1095565	50,407,056	31,149,468
2034	159	144313	2543	619894	308405	200463	200463	29798	6647633	-988128	1017926	51,424,982	**32,167,394**

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