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Site-specific Design Case Study for Wet Waste Hydrothermal Liquefaction and Biocrude Upgrading to Hydrocarbon Fuels

December 2024

U.S. DEPARTMENT OF ENERGY

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Summary

Hydrothermal liquefaction (HTL) is a thermal process that converts wet biomass to renewable hydrocarbon fuel blendstocks (i.e., renewable naphtha, renewable diesel, and sustainable aviation fuel (SAF)). It can utilize a wide range of pure and blended wet feedstocks, including sewage sludge from water resource recovery facilities (WRRF), food and agriculture wastes, algae, fats, oils and greases (FOG) and blends of dry and wet wastes/feedstocks. Historically, techno-economic analysis (TEA) and annual state of technology (SOT) assessments with standard economic assumptions used by the Bioenergy Technologies Office (BETO) were conducted for the wet waste HTL pathway leveraging experimental data collected from Pacific Northwest National Laboratory's (PNNL) continuous flow reactor systems. The objective of the SOT assessment has been to guide and track progress of BETO's HTL research and development (R&D) toward reduced cost and greenhouse gas (GHG) emissions for the pathway. However, gaps exist between BETO's traditional SOT updates and the needs of key external stakeholders that – if addressed – will accelerate technology adoption.

This Business Case Study aims to bridge this gap by providing an updated design, TEA, and LCA based on PNNL's FY23 R&D with added analyses and information that provide enhanced relevance for stakeholders[1] of the HTL technology. This includes specific siting, regional wet waste resource inventory and transportation cost analyses, fuel market information, sustainable fuel policy impacts, economic metrics of net present value (NPV) and internal rate of return (IRR), greenhouse gas (GHG) emissions analysis, and statistical analysis of cost and technical uncertainties of the HTL plant design. The study focuses on the "Detroit combined statistical area (CSA)" region for siting of a wet waste HTL plant adjacent to the Great Lakes Water Authority (GLWA) facility with guidance from industry participants. Regional resource and siting analyses were conducted to identify feedstock availability, scale, and cost, as well as a beneficial site location. TEA with detailed rigorous capital cost estimation for the specific site application was conducted to evaluate the key economic metrics of most value to industrial partners. These include total capital investment, operating costs, minimum fuel selling price (MFSP) of the biocrude and fuel blendstock, and NPV and internal rate of return IRR with sustainable fuel credits. Life cycle analysis was conducted to evaluate the supply chain greenhouse gas (GHG) emissions for the wet waste HTL process as compared with petroleum derived diesel.

This study is also informed by years of R&D and process de-risking learnings and was conducted with a basic engineering HTL plant design and costing that akin to a "first-of-a-kind" plant economics. This differs from our conventional "n^{th} plant[2]" SOT assessments. Specifically, the HTL process model has been updated with more operationally reliable methods for feed heating and phase separations. Further, we have implemented additional spare equipment for redundancy, a more rigorous installed equipment cost estimation approach, and additional costs associated with feed formatting and delivery, building, piping and site development. An Excel-based cost sheet based on the basic engineering design is also released alongside the report that allows users to conduct customized TEA with their own feed composition and financial assumptions.

The key study findings are summarized below.

Policy. Several federal and state level programs are available to provide economic support that incentivizes the production of sustainable biofuels, including the Renewable Fuel Standard (RFS), blender's tax credits (BTCs), Inflation Reduction Act (IRA), and potential state level clean fuel programs (CFPs). The average of combined credits possible was determined to be $3.31/GGE.

[1] Note: The business case study includes assumptions and is specific to one conceptual application and should not be used by stakeholders as a detailed design. Cost estimates are based on our approach, and stakeholders are advised to create their own estimates based on the fidelity needed for decision making.
[2] N^{th} plant refers to any subsequent plant that follows the "first of a kind" (FOAK). It benefits from the experience gained during the FOAK stage, and therefore is typically much cheaper than the FOAK.

Plant siting. This study focuses on a location at the southeast of the GLWA facility, in Detroit as an example. This site was chosen because GLWA is one of the largest WRRFs in the U.S. and is interested in the viability of HTL as an alternative solution to their incineration line. In addition, a nearby petroleum refinery would consider co-processing biocrude if potential benefits and risks are fully identified and evaluated. From the biorefinery perspective, leveraging the existing infrastructure provides significant cost savings for producing hydrocarbon fuel blendstocks. However, to data there is no identification of interest by refineries in this region.

Resource assessment. A regional feedstock resource assessment was conducted for wastewater sludge, wastewater scum and non-residential food waste within the Detroit-Warren-Ann Arbor combined statistical area (“Detroit CSA”). This study suggests that up to 1,217 dry short ton/day of wet waste blended feedstock can be delivered to the study site with a reasonable transportation cost for a modest-scale HTL plant.

Technology de-risking. Basic engineering process designs were developed “pain points” of plant operations to further de-risk the technology and address scale-up challenges. Direct heating with injection of steam from the HTL reactor effluent was implemented in place of the low temperature heat exchangers to reduce the risk of fouling and plugging. Solvent extraction and medium-pressure gravity separation were considered as two alternatives to the original design’s high-pressure blowdown methods that has potential engineering challenges at the commercial scale These process design modifications would not significantly impact the cost estimation and GHG emissions from this pathway.

Minimum fuel selling price for 110 ton/day base case. The estimated MFSP of the biocrude for a 110 dry short ton/day wet waste HTL plant is $4.11/gasoline gallon equivalent (GGE) when medium-pressure gravity separation is used for HTL solid separation, and $4.37/GGE when solvent extraction is used. The estimated MFSP of hydrocarbon fuel blendstocks from HTL is about $4.90/GGE and $5.16/GGE, respectively for the two solid separation methods, assuming biocrude is upgraded at a nearby petroleum refinery.

Net present value / internal rate of return for 110 ton/day base case. Plant NPV and IRR depend heavily on sustainable fuel credits. When the price of HTL biocrude is fixed to its market value, a sustainable fuel credit of $1.8/GGE is needed to achieve a positive NPV. This falls in historical RIN D5 price in the last 5 years, ranging from $0.15-4.43/GGE with an average of$1.48/GGE.

Greenhouse gas emissions. The estimated supply chain GHG emissions of renewable hydrocarbon fuel from HTL is 21.8 g CO_{2e}/MJ when using gravity separation, and 30.5 g CO_{2e}/MJ when using solvent extraction, which is 76% and 66% lower than that of petroleum diesel (91 g CO_{2e}/MJ), respectively. For both scenarios, the major contributor to the total GHG emission are the emissions during biocrude production in the HTL plant. The solvent extraction scenario has higher GHG emission because of the use of the organic solvent (contributing 3.7 g CO_{2e}/MJ if using toluene or 2.0 g CO_{2e}/MJ if using reformate) and the additional energy consumptions associated with the solvent extraction unit operation (contributing 5.2 g CO_{2e}/MJ). It is expected that these additional emissions associated with solvent extraction can be mitigated with further technology development described below.

Uncertainties. Uncertainties in feedstock composition, process model accuracy, pricing assumptions, and equipment sizing and cost estimation will result in a +/- 6% deviation (from 60.4% to 68.1%)in the estimated process carbon efficiency, a +/- 7% deviation (from 65.0% to 75.0%)in the estimated process thermal efficiency, a +23%/-7% deviation (from $3.83/GGE to $5.06/GGE) in the estimated biocrude MFSP, and a +23%/-5% deviation (from 89 MM$ to 114.9 MM$) in the estimated total capital investment. These uncertainties can be reduced with continuous technology development.

Plant scale and fuel selling price. Plant scale is a key economic driver for commercial processes. For scales larger than the base case, the plant size ranges from 933 to 1,217 dry short ton/day, representing 100% sludge utilization plus 0% to 71.7% food waste utilization in the Detroit CSA. The estimated biocrude MFSP is $1.49/GGE, $1.66/GGE, $1.78/GGE and $1.96/GGE for a plant scale of 933, 1073, 1131, 1217 dry ton/day, significantly lower than that of the base case design with a plant scale of 110 dry ton/day. The estimated biocrude MFSP increases with scale because the average transportation cost of food waste increases when more long-distance and small food waste point sources are included to boost the regional food waste utilization for fuel production. Biocrude upgrading at the nearby petroleum refinery will add $0.44 per GGE of finished fuel blendstock produced.

Several pilot and demonstration projects are in planning, construction, or operational status. Future work as listed below is needed to further advance the technology readiness level, reduce costs and supply chain GHG emissions, and bolster a successful business case.

Assessment method improvement. Improve the model accuracy for two de-risking strategies (direct steam injection for pre-heating, and solvent extraction for separation), feedstock supply chain and variation.

HTL technology de-risking and improvement. Explore alternative HTL aqueous-phase treatment methods, PFAS mitigation strategy, nutrient recovery method, and autothermal HTL with solvent extraction.

Biocrude upgrading de-risking and improvement: Demonstrate the biocrude hydrocracking performance for targeted fuel products, evaluate impact of heteroatom contents in the HTL biocrude, and improve hydrotreating catalyst lifetime.

Table S.1. Summary of key findings

Key Performance Parameter	Value
Plant Siting	Co-locate with GLWA WRRF
Regional Resource Assessment	
Scale	up to 1,217 dry short ton/day blended wet waste
Resource Type	wastewater sludge, wastewater scum and non-residential food waste
Base Case	
HTL Plant Scale	110 dry ton/day sludge
Minimum fuel selling price (MFSP) of Biocrude	$4.11/ (GGE) for HTL with gravity separation $4.37/GGE for HTL with solvent extraction
MFSP Uncertainties of Biocrude	$3.83- $5.06/GGE
GHG emissions	21.8 g CO2e/MJ for HTL with gravity separation, 30.5 g CO2e/MJ for HTL with solvent extraction
Large Scale/Hot Spot Case	
933dry ton/day MFSP of biocrude	$1.49/GGE
1073dry ton/day MFSP of biocrude	$1.66/GGE
1131dry ton/day MFSP of biocrude	$1.78/GGE
1217 dry ton/day MFSP of biocrude	$1.96/GGE

Acronyms and Abbreviations

ACCE	Aspen Capital Cost Estimator
AD	anaerobic digestion
ADWF	average dry weather flow
AFDW	ash-free dry weight
BAU	business-as-usual
BETO	Bioenergy Technologies Office
BEV	break-even value
BTC	blender’s tax credits
CCCSD	Central Contra Costa Sanitary District
CFP	clean fuel programs
COD	chemical oxygen demand
CSA	combined statistical area
CSTR	continuous stirred-tank reactor
EBS	engineered bioslurry
FCI	fixed capital investment
FOG	fats, oils, and grease
FP	first preheat
FY	fiscal year
GGE	gasoline-gallon equivalent
GHG	greenhouse gas
GLWA	Great Lakes Water Authority
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies
HP	high pressure
HTL	hydrothermal liquefaction
IIC	industrial, institutional, and commercial
IRA	Inflation Reduction Acts
IRR	internal rate of return
JBLM	Joint Base Lewis McChord
LCA	life cycle analysis
LCFS	low-carbon fuel standard
LP	low pressure
MFSP	minimum fuel selling price
MHTLS	modular hydrothermal liquefaction system
NAICS	North American Industry Classification System
NPV	net present value
OFMSW	Organic fraction of municipal solid waste

PFD	process flow diagram
PFR	plug-flow reactor
PNNL	Pacific Northwest National Laboratory
R&D	research & development
RFS	Renewable Fuel Standard
SAF	sustainable aviation fuel
SIMDIS	simulated distillation
SOT	state of technology
TCI	total capital investment
TDC	total direct cost
TEA	techno-economic analysis
VOCs	volatile organics
WHSV	weight hourly space velocity
WRRF	wastewater treatment and water resource recovery facility

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1.0 Introduction

The Department of Energy's Bioenergy Technologies Office (BETO) conducts research & development (R&D) of new technologies that can convert biomass to sustainable fuels and chemicals. Historically, BETO's primary tool for evaluating biofuel technologies and tracking R&D progress toward technical, environmental, and cost targets has been hypothetical pathway design cases and state of technology (SOT) assessments based on laboratory-scale experimental campaigns. The design case is typically developed early in the pathway R&D to set technical and cost targets and the SOTs are conducted annually to measure progress toward those targets. Hypothetical designs are often re-evaluated every few years and updated to reflect lessons learned, as well as current thinking about real-world implementation. Design cases and SOTs for each of BETO's priority biofuel pathways are highlighted in their strategic planning document, the Multi-Year Program Plan (BETO 2023). These analyses have been highly effective in guiding research and reducing modeled "n^{th} plant" (DOE 2023) costs and greenhouse gas (GHG) emissions through integrated experimental research, techno-economic analysis (TEA) and life cycle analysis (LCA). However, moving forward BETO is focusing on analyses that not only continue to drive the R&D but also provide maximum relevance for technology stakeholders. To accomplish this, a key outcome is a Business Case Study that features a specified site/region and provides critical outputs relevant for preliminary feasibility and business planning. Ideally, the studies will be performed with industry partners to incorporate as much realism as possible into the analysis and assumptions. The purpose of the Business Case Study is to continue providing data-grounded analyses but with emphasis on bridging the gap between BETO's traditional, hypothetical pathway TEAs and SOT updates and the needs of key external stakeholders to help accelerate technology adoption.

Hydrothermal liquefaction (HTL) is one of several technologies that that can convert biomass to renewable hydrocarbon fuel blendstocks including renewable naphtha, renewable diesel, and sustainable aviation fuel (SAF). HTL uses water as the conversion reaction medium and therefore is advantageous for wet feedstocks as biomass drying energy can be minimized or eliminated. The HTL technology can also utilize a wide range of pure and blended feedstocks, including sewage sludge from water resource recovery facilities (WRRF), food and agriculture wastes, algae, fats, oils and greases (FOG) and many others. Since 2017, PNNL has been performing R&D along SOT assessments for BETO's wet waste HTL pathway (Snowden-Swan etc., 2017, 2018, 2022a).

The Business Case Study (business case) herein provides an update of the wet waste hydrothermal liquefaction (HTL) pathway R&D, modeling, TEA, and LCA for Fiscal Year (FY) 2023, with additional information relative to past SOT assessments aiming to enhance value for industry stakeholders. This includes specified siting, regional wet waste resource inventory and transportation cost analyses, fuel market information, sustainable fuel policy impacts, economic metrics of net present value (NPV) and internal rate of return (IRR), and statistical analysis of cost and technical uncertainties of the HTL plant design. Deployment of HTL is conceptualized at an example site, namely the Detroit water resource recovery facility (WRRF) managed by the Great Lakes Water Authority (GLWA). The site was chosen because GLWA is one of the largest WRRFs in the country and the PNNL team has had a longstanding working research relationship with them. GLWA also leads an ongoing project focusing on community acceptance and social economic issues of installing HTL plant for treating sludge from WRRF. Site specific details generally relevant for deployment are assessed including a detailed feedstock assessment for the Detroit and surrounding area, land availability and proximity to refineries for co-processing. Valuable insights from Gibby Group on the logistics and business of wet waste resourcing and distribution were integrated into the siting and feedstock assessment for the large-scale case. Previous SOT assessments for the waste HTL pathway did not include the revenue potential from renewable identification numbers (RIN) under the Renewable Fuel Standard (RFS) and other carbon programs. These incentives, along with sensitivity analysis to account for price volatility, are included here to assess the potential economic impact of renewable fuel carbon credits being realized on the market today.

This study is also informed by several years of R&D and learnings from PNNL's de-risking and scale-up work and provides a more robust and detailed process HTL plant design and costing that is consequently better aligned with "first-of-a-kind" plant economics compared with our previous n^{th} plant design case and SOT analyses (Snowden-Swan et al. 2017). The HTL plant process design and model is updated from the last (2022) SOT (Snowden-Swan *et al.*, 2022a) to incorporate alternative methods for feed heating and phase separation that provide a reduced risk process design. The detailed process flow sheets, stream tables, equipment list, and discounted cash flow worksheet are provided in the report appendices. In addition, we have implemented additional spare equipment, a more rigorous installed equipment cost estimation approach, and additional costs associated with building, piping and site development. Finally, sensitivity and uncertainty analysis were conducted to evaluate the individual and combined impacts from feedstock composition, process model accuracy, economic assumptions and equipment sizing and cost on the key economic performance of the wet waste HTL plant.

The intended stakeholders for this study and report include but are not limited to BETO, municipalities, waste hauling and management companies, WRRFs, and fuel producers and blenders. The report is meant to provide stakeholders[1] with detailed information including complete energy and mass balances as well as equipment sizing and cost information. Such data aims to offer a broad comprehension of the potential advantages and challenges associated with this technology. It is not our intention to suggest that this technology is only appropriate as deployed as described in this report. There are several teams working diligently around the globe on various configurations of this biomass conversion pathway. It is our hope that stakeholders can use this information to apply to their own site to aid decisions on future waste management and waste-to-energy options.

[1] Note: The business case study includes assumptions and is specific to one conceptual application and should not be used by stakeholders as a detailed design. Cost estimates are based on our approach, and stakeholders are advised to use create their own estimates based on the fidelity needed for decision making.

2.0 Fuel Market and Drivers for Waste-to-Fuels

Energy and fuel serve as vital pillars of the United States' economy and society. Meeting the nation's total energy demands entails a diverse array of resources. In 2022, the United States's primary energy consumption amounted to approximately 94 quadrillion btu, with the petroleum and natural gas accounting for roughly 72% of the total (Figure 1). The demand for petroleum is largely driven by its use of transportation fuels for cars, trucks, ships, airplanes, and trains. Greenhouse gas (GHG) emissions from transportation account for about 29% of total U.S. greenhouse gas emissions, making it the largest contributor of U.S. GHG emissions. To meet the White House's National Climate Task Force's goal of reducing GHG emissions 50-52% below 2005 levels by 2030, biofuel emerges as one of the most promising options to replace conventional fossil liquid fuels, aligning with emission reduction targets set for mid-century without necessitating major alterations to existing internal combustion engines and fuel infrastructure. This seamless transition potentially makes biofuels an attractive choice for the transportation sector and other industries, especially for the sectors that are unlikely to be able to electrify near term.

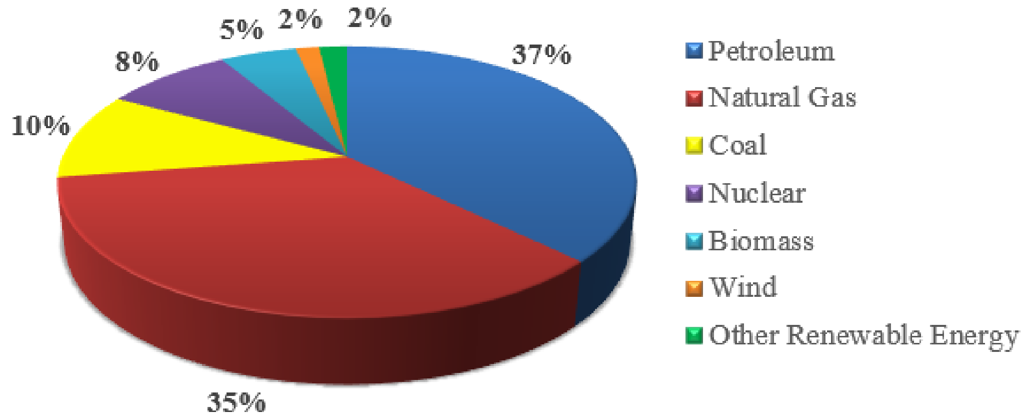


Figure 1. United States Energy Consumption by Source in 2022 (Source: U.S. Energy Information Administration (EIA))

Additionally, biofuels share similar properties with current liquid fuels, allowing them to serve as readily deployable, drop-in replacements. Currently, there are several established commercial biofuel markets both in the United States and globally. These include the conversion of corn to ethanol through fermentation, the transformation of vegetable/soybean oil into biodiesel through transesterification, and the production of renewable diesel from hydroprocessing of waste and other non-food feedstocks. The versatility of biofuel production extends to various feedstock sources, including crops, agricultural residues, algae, and waste materials. This adaptability facilitates alignment with regional resource availability and agricultural conditions. Also, the production of biofuels can contribute to energy independence by utilizing locally available feedstocks and reducing the fossil fuels demand.

In 2021, Michigan and the neighboring states (Ohio and Indiana) together consumed close to 9000 trillion btu, about 9% of the total energy consumption in Unite States, as shown in Table 1. Of the total energy consumption, the transportation energy consumption for all of three states range from 21%-26%. Additionally, the combined use of petroleum, natural gas and coal in these three states represents roughly 7%, 10% and 15% of the national usage, respectively, while the renewable energy consumption shares of the state total energy consumption are noticeably lower than the national average value. Michigan produced 320 million gallon ethanol and 15 million gallons of biodiesel and consumed more than it produced in 2021, predicting a large biofuel market for meeting the biofuel demand and GHG emission goal.

Table 1. Energy Consumption in Michigan and the neighboring states

Energy	MI	OH	IN	US
Total Consumption (trillion Btu)	2711	3543	2728	97547
Renewable Energy Consumption as a Share of State Total (%)	9.1	4.7	7.8	12.4
Transportation (trillion Btu)	711	876	586	27072
Petroleum (million barrels)	165	203	139	7260
Natural Gas (billion cu ft)	899	1211	827	30615
Coal (million short tons)	22	23	33	546

Considering the feedstock limitation and huge biofuel demand market, it is very compelling to produce biofuel from organic waste, such as sewage sludge, food waste, animal manure, and municipal solid waste, et al. As populations grow and urbanize, waste management becomes a critical issue. Waste-to-fuels technologies offer an alternative to traditional waste disposal methods, which may be reaching capacity limits in many areas. Waste-to-fuels technologies offer a more sustainable and environmentally friendly solution for managing waste materials. These processes can help divert waste from landfills, reducing the environmental impact of landfilling, such as methane emissions and groundwater contamination.

3.0 Policy Supporting Biofuels

The current and proposed government programs that support biofuels development aim to serve two purposes: 1) quantifying the environmental advantages associated with sustainable fuels; and 2) providing financial assistance to help biofuel development and deployment. Understanding the current supporting policies is essential not only for financial planning and decision-making, but also for navigating the complex landscape of the sustainable fuel market while managing the associated risks. The list of programs incentivizing the development and use of reduced-carbon biofuels continues to grow. Discussed in this section are a few of the key policies currently in place and their potential impacts on plant siting.

3.1 Federal Sustainable Fuels Programs

The Renewable Fuel Standard (RFS) is a U.S. federal program that requires and encourages the use of renewable fuels in the U.S. transportation sector. As part of the RFS, the Renewable Identification Numbers (RIN) system was created to track compliance and trading credits and establish rules for waivers. The RFS establishes a marketplace for the sale and purchase of RINs to meet renewable volume obligations. Renewable fuel producers are required to meet GHG emissions reductions to obtain RINs. The RIN value is dependent on the RIN/fuel type, timeframe selected, production technology and feedstock. A tiered network strategy is used to define RIN values. The average value per RIN type between 2018-2022 was selected for this analysis. Each approved conversion pathway has an associated RIN code designated by the EPA (US EPA, 2023). The reported RIN values are scaled based on the energy density of the fuel. For this study, RINs were modeled as taxable income and subject to inflation, so the value increases over the plant life.

A variety of existing and proposed federal blender's tax credits (BTCs) exist to reduce the tax burden of a fuel blender. In the existing biomass based BTC, the blender earns the credit as tax-free income once their tax burden has been erased. The recently passed Inflation Reduction Act (IRA) extended the current BTCs to 2024. $1.00/gallon of the tax credits can be obtained for non SAF sustainable fuel with carbon intensity (CI) less than 50 kg CO_2e/ MMBTU while $1.25/gal credits can be received for SAF with 50% CI reduction and the SAF tax credits can ramp up to $1.75/gallon for 100% GHG emission reduction or greater.

3.2 State Programs (e.g., LCFS, CFP)

As reported by Renewable Fuel Associated, many state policies have already been implemented or are in the process of being implemented to encourage the production and use of sustainable fuels to meet their state emissions goals. The first such program to be enacted was California's low-carbon fuel standard (LCFS), which pays energy producers based on the tons of carbon dioxide equivalent per MJ fuel (tCO2e/MJ) avoided (*California Air Resources Board (CARB)*, 2023). Each producer's CI is tracked with the producer being paid a premium per unit of fuel based on the quantity of the avoided carbon emissions. This model encourages continuous reductions in CI scores while also rewarding small CI changes. Similar programs have been implemented in Oregon in 2016 (Oregon Department of Environmental Quality, 2023) and in Washington State (Department of Ecology, 2023) in 2023. Many other states also consider adopting similar LCFS or CFP to meet their specific GHG targets for supporting for climate action. In Michigan state, a bill to implement a clean fuel standard was announced on April 12, 2023. The bill would establish a clean fuel standard that will decrease the carbon intensity of fuels in Michigan by 25% by 2035 (*Michigan Clean Fuel Standard*, 2023).

3.3 Other Supporting Policies/Incentives

Intensive capital costs and the lack of commercial-scale deployment are among the main concerns for investors of emerging fuel technologies such as HTL. To mitigate financial risks and attract more investment, incentives play a pivotal role. One effective approach is the utilization of capital grants, which serve to reduce the financial burden on investors and encourage their participation in projects. In the past, several illustrative U.S. examples demonstrate the impact of such incentives. In 2014, Red Rock Biofuels secured a grant of $70 million under the United States Defense Production Act Title III Advanced Drop-in Biofuels project during its second phase. This grant supplemented the initial $4.1 million received in the first phase for engineering purposes, resulting in a total grant of nearly $75 million (Steve Lynn, 2014). Similarly, the Department of Defense extended funding support to Fulcrum BioEnergy, providing a grant of $70 million for their municipal solid waste (MSW)-to-fuel facility in Nevada (Harry Reid, 2014). Additionally, Fulcrum BioEnergy received $4.7 million in phase 1 of the project for engineering efforts, culminating in a total grant amount of $74.7 million (Schill, 2013). The recent past IRA continues to provide incentives to support the SAF, biodiesel, and other biofuels industrial in addition to the tax credits for reducing financial barriers and fast deploying sustainable energy solutions. Specifically, IRA provides $10 million grants for the advancement of biofuel industries, and $500 million in funds for biofuel infrastructure improvement through 2034.

3.4 Potential Impact on HTL Fuel Selling Price

With the obtained information on the federal and state policy support on the sustainable fuel, the potential impact for HTL-based fuel was estimated. Figure 2 shows the potential sustainable fuel credits from the currently available state and federal policy support. The tax reduction credits are anticipated to be shared between biofuel producers and fuel blenders, with an average credit of $0.50/GGE. The range of BTC credit error bar, which is between $0-$1.00/GGE, indicates the absence of credits and the highest possible credits for the HTL facility in extreme situations. Over the past five years, daily RIN D5 prices have fluctuated significantly, ranging from $0.10 to $2.94/ethanol gallon equivalent with an average value of approximately $0.98/ ethanol gallon equivalent. As shown, the converted RIN D5 credits in the last five years is $0.15-4.43/GGE with an average of $1.48/GGE. Similarly, over the last three years, LCFS credit values have fluctuated between $75 and $211/metric ton. Using an average carbon credit value of $169/MT and a 70% CI reduction for HTL biocrude, the potential average carbon credits from LCFS amount to approximately $1.33/GGE with the range from $0.59 -$1.66/GGE. In summary, when considering tax credits, D5 RINs, and LCFS incentives, the total incentive package amounts to around $3.31/GGE. However, when accounting for the maximum and minimum values for BTCs, RINs and LCFS credits, the stacked incentive range widens considerably, spanning from $0.74 to $7.10/GGE.

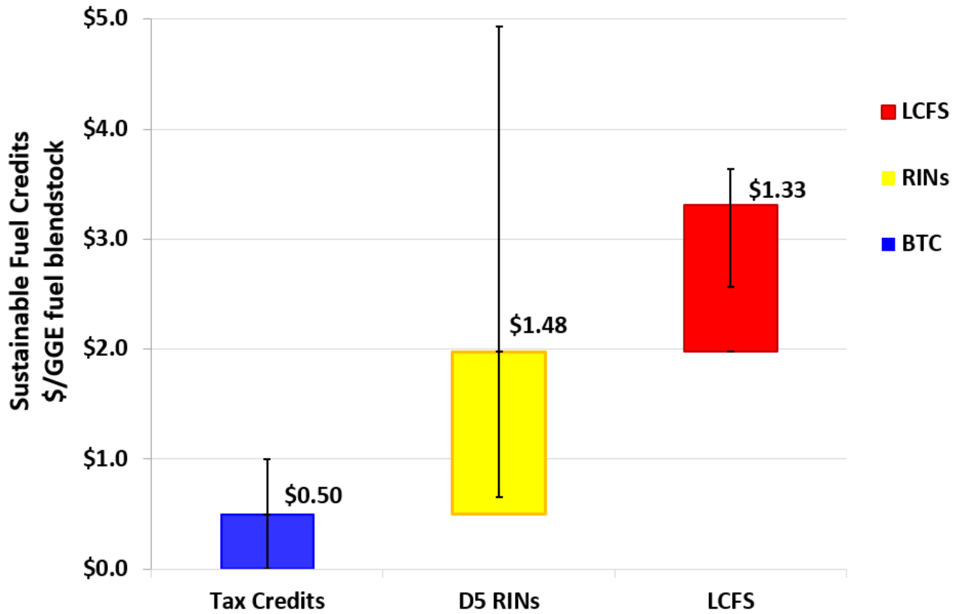


Figure 2 Cumulative Sustainable Fuel Credits from the Available State and Federal Policy Support

3.5 Potential Impact on HTL Plant Siting

The complex interplay of state-level policies (i.e., LCFS) with federal programs (i.e., RFS) significantly impacts biorefinery siting decisions. Understanding these policy drivers is crucial for HTL plant developers, investors, and stakeholders to promote biofuel production. By carefully considering the incentives, regulations, and restrictions imposed by different states, the HTL plant can be strategically located to maximize both economic and environmental benefits and minimize project risks. States with consistent and supportive policies can attract more stable investments and accelerate technology deployment.

4.0 Regional Resource Assessment

Organic waste feedstocks in the Detroit region were recently characterized by PNNL (PNNL, 2023). This study considers (1) untreated, dewatered wastewater sludge solids, (2) wastewater scum, and (3) non-residential food waste inventoried within the 2020 U.S. Census Bureau cartographic boundary (1:500,000) for the Detroit-Warren-Ann Arbor combined statistical area ("Detroit CSA") (U.S. Census Bureau., 2020). The Detroit CSA (Figure 3) is comprised of ten counties including Genesee, Lapeer, Lenawee, Livingston, Macomb, Monroe, Oakland, St. Clair, Washtenaw, and Wayne.

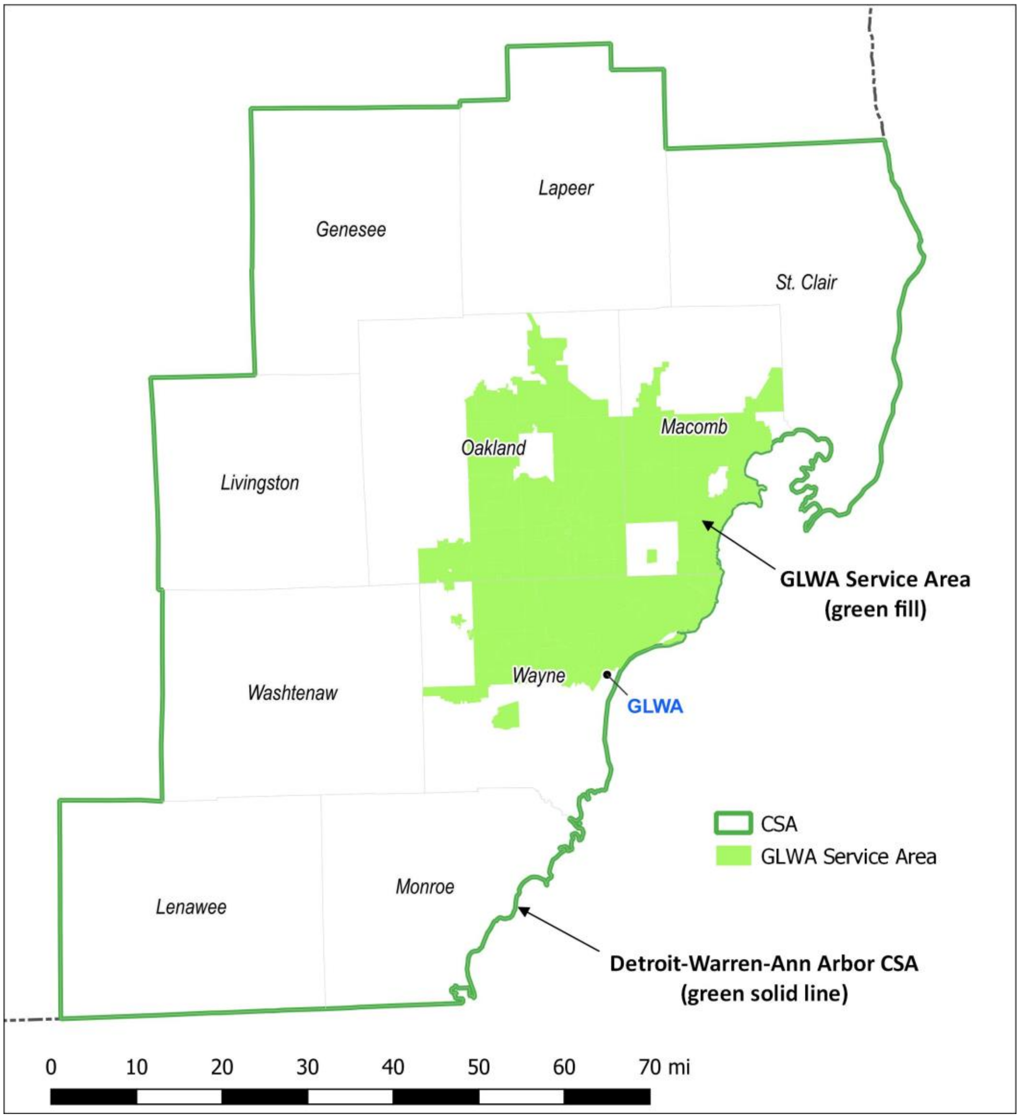


Figure 3. Map of study boundary

Table 2 summarizes feedstock quantity and physical properties. Depending on which food waste estimates are considered (low or high), approximately 950 to 1,460 dry metric tons per day of target feedstocks occur within the Detroit CSA, of which 58 to 90 percent is comprised of sludge. Feedstock proportions are similar within the GLWA service area, which contains 630 to 926 dry metric t/d of feedstock, of which 61 to 90 percent is sludge.

Dry mass to wet mass conversion involves dividing the dry solids mass by the solid concentration of transported waste. Converting wet mass to wet volume involves dividing wet mass by average density factors (kg/m^3) obtained from literature. Density values for scum were not available in wastewater literature because scum is not typically characterized or measured, therefore we assume the same density as water.

Food waste materials are typically compacted during pick-up, which greatly reduces the number of required trips. Sludge and scum are loaded as uncompacted material, meaning the as-produced and as-delivered density is the same. In our simplified truck scheduling approach, the compaction factor only matters for sources that require >1 trips per week.

Table 2. Feedstock characteristics

Property	Unit	Wastewater Solids	Wastewater Scum	Non-residential Food Waste	Notes
mass (within CSA)	dry metric t/d	843	3	103–618	
mass (within GLWA)	dry metric t/d	569	*3*	*58-354*	
solids content	%	25	70	30	As delivered by truck
density	kg/m^3	1050	1000	330	Dewatered sludge (IWA, 2007); uncompacted SSO at 557 lb/yd^3 (MPCA, 2021)
transport density	kg/m^3	1050	1000	593	Food: RotoPac 27R min. compaction rating (New Way, 2022).

4.1 Wastewater Treatment Solids

In this study, wastewater solids ("sludge") refers to dewatered solids removed directly from primary and secondary treatment, prior to any stabilization or further treatment (e.g., AD), which typically reduces solids mass and organic content. The baseline scenario assumes dewatered sludge has a solids content of 25%, which is consistent with the average solids concentration for the three most common dewatering technologies of 28%. To further reduce costs, more concentrated solids could be transported and diluted with HTL aqueous phase.

Table 3. Typical sludge dewatering performance

	Solids Concentration (%)	
dewatering technology	**Range**	**Typical**
belt filter press, with chemicals	18-30	23
centrifuge, with chemicals	15-35	24
filter press, with chemicals	20-45	38
average		**28**

A total of 81 water resource recovery facilities (WRRF) occur within the Detroit CSA and treat an average of 973 million gallons of wastewater per day (MM gal/d) producing approximately 843 dry metric tons per day of wastewater solids (Table C.1). The WRRFs range in treatment capacity from 0.03 to 660 million gallons per day of average dry weight flow (ADWF). The GLWA treatment facility, the largest WRRF in the region, serves 2.7 million inhabitants and accounts for 68% of total influent flow (and solids) in the Detroit CSA. The ten largest WRRFs in the region account for greater than 90% of treated wastewater and solids production. Figure 4 illustrates the spatial and ADWF treatment capacity distribution for WRRFs in the Detroit CSA.

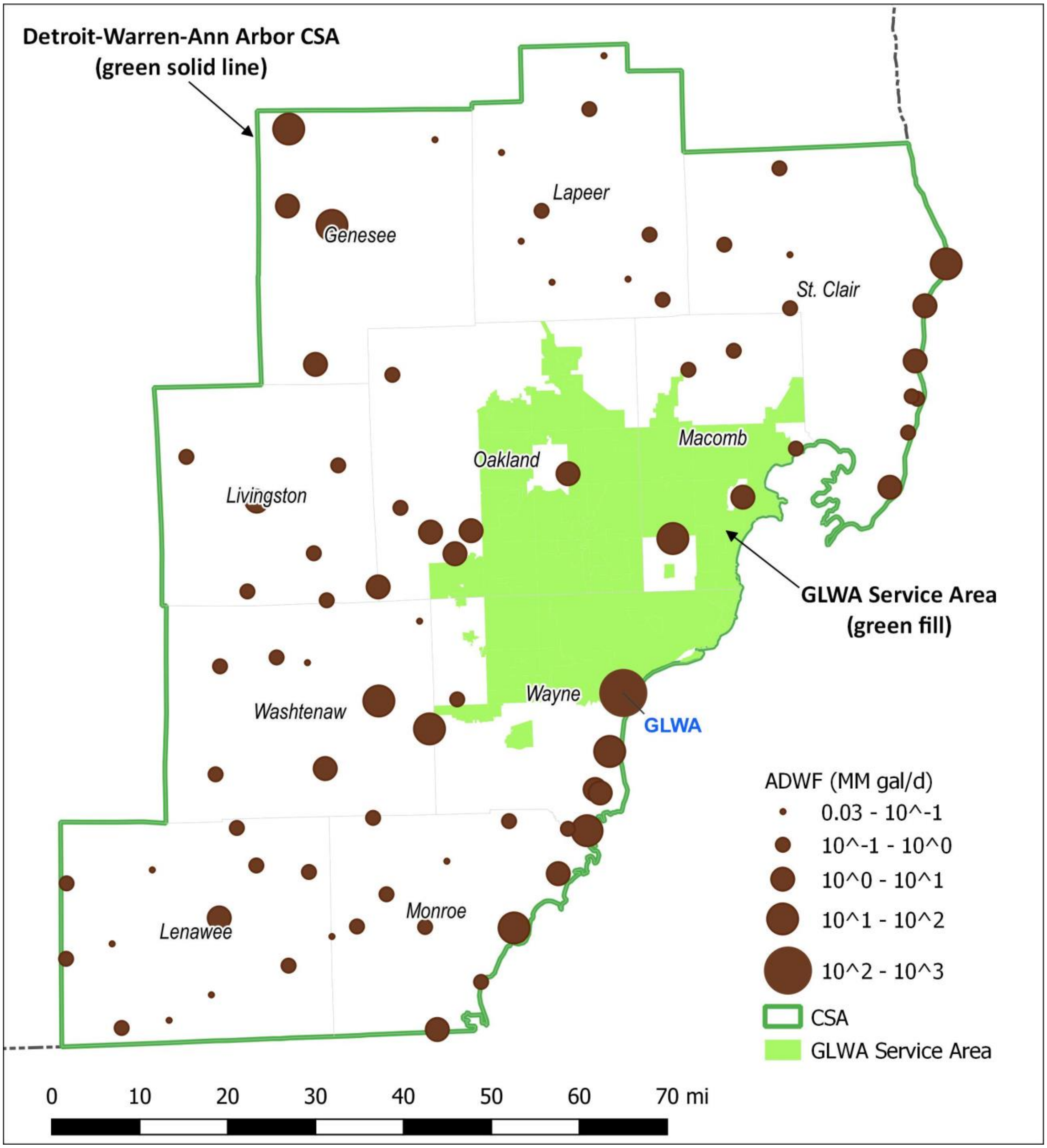


Figure 4. Spatial and capacity distribution of WRRFs in the Detroit CSA

4.2 Wastewater Scum

Wastewater scum refers to material collected during treatment in grease traps or skimmed from the surface of flows influent to primary and secondary treatment. Scum collected from primary treatment typically consists of FOG and floating contaminants such as debris, plastic, and rubber products, while scum collected from secondary treatment is comprised mostly of floating activated sludge or biofilm, depending on treatment process. Additional quantities of scum may also be available from the cleanout of conveyance systems (i.e., "fat bergs"), but are not included in this study due to lack of reporting data.

Wastewater scum quantity and solids content are not typically measured, and the material is generally landfilled. In this study we assume the scum has a solids concentration of 70%. We only include scum estimates for GLWA because it is the only WRRF for which we had scum removal reporting data. GLWA data indicate a monthly average removal rate of only 85 tons per month.

4.3 Non-Residential Food Waste

Food waste is typically classified by source as residential and non-residential. Although residential source material represents the largest portion of food waste in landfills, the absence of an organics disposal ban in Michigan means the residential waste is co-mingled with other types of municipal solid waste (MSW) and more difficult (expensive) to separate and access. In comparison, non-residential food waste, which includes industrial, institutional, and commercial (IIC) waste sources, is generally less contaminated and easier to access in large quantities.

PNNL (2023) reported both low and high estimates for food waste, consistent with the underlying EPA methodology (US EPA, 2020). It is important to understand that the EPA modeled food waste estimates, while based on establishment level location and business data, may not reflect actual site conditions (i.e., food waste production) for any given location. There are a variety of reasons, including but not limited to (1) a change in business status; (2) incorrectly assigning production data to corporate office locations rather than processing locations; (3) grouping multiple store locations into a single business record; (4) inaccurate business data used for scaling (e.g., number of employees, revenue, etc.); (5) inaccurate geolocation information; or (6) waste estimation error. However, the modeled dataset still provides valuable information regarding which types of food waste producers are likely active in the region and the relative quantity of waste produced by each food sector.

In this study, we assume a solids concentration of 30% for all food waste types. Substantial cost reductions could be achieved in the future by implementing on-site food waste compaction prior to pickup, which reduces moisture content and therefore the required number of trips per year. Food waste mass is estimated using the average of the EPA's low and high establishment level food excess estimates.

Table 4 presents total annual food waste mass (dry metric t/d) by market sector, for all sources that could be geolocated. The EPA estimated average of 360 dry metric tons per day of total non-residential food waste is generally consistent with the 439 dry metric t/d of non-residential food waste disposed as part of Michigan's 828 dry metric t/d organic fraction of municipal solid waste (OFMSW) (PNNL, 2023), assuming 53% of total disposed OFMSW is from commercial sources (NextCycle, 2021). Non-residential food waste sources range in size from 0.01 to 762 dry metric t/y. Figure 5 illustrates the spatial distribution of food waste within the Detroit CSA. Table C.2 in Appendix C summarizes food waste sources by North American Industry Classification System (NAICS) categories.

Table 4. Average food waste mass by sector

Food Waste Type	Count	Average (dry metric t/d)
TOTAL	**16,544**	**360.1**

Correctional Facilities	42	2.3
Educational Institutions	1953	25.0
Food Manufacturers & Processors	679	31.2
Food Wholesale and Retail	3425	172.6
Healthcare Facilities	68	4.4
Hospitality Industry	719	9.7
Restaurant & Food Services	9658	115.0

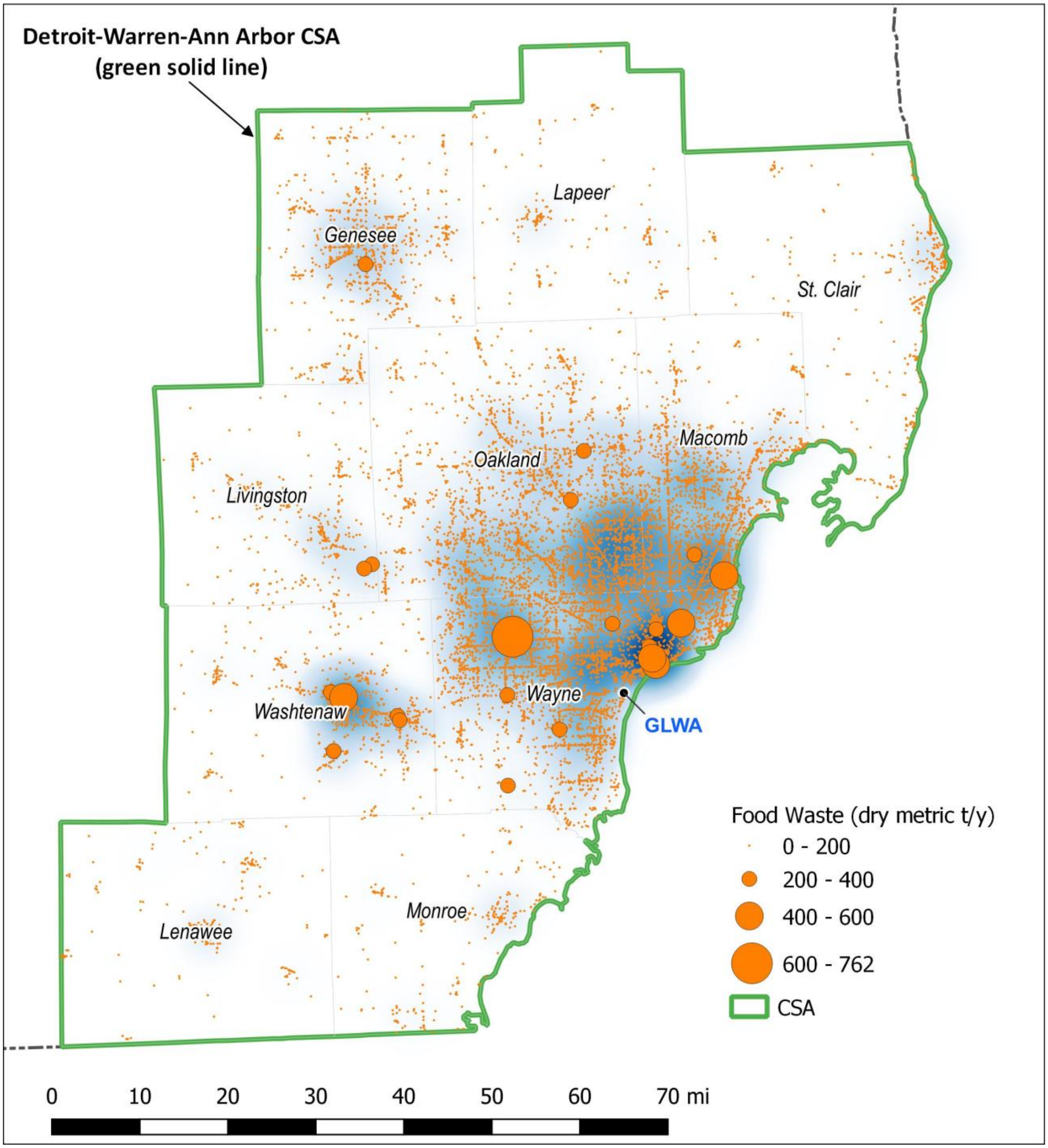


Figure 5. Distribution of food waste in the Detroit CSA

4.4 Potential Feedstock Price for the Analysis

The commercialization of HTL could be transformative for the treatment and reuse of wastewater solids and the organic fraction of municipal solid waste, especially food waste. The literature (Elliott *et al.*, 2015; Mulchandani et al., 2016; Seiple *et al.*, 2020) describes key potential benefits of HTL for the wastewater sector, including (1) sterilized bioactive contaminants and pathogens; (2) faster loading rates (100x), better solids reduction than AD; (3) operating with 5–30% solids avoids solids dewatering/drying energy and costs; (4) increased dewaterability and odor reduction of residual biosolids; (5) potential to reduce national biosolids disposal costs by more than $1 B/y; (6) contributes to decarbonization goals by (a) reducing direct process and fugitive GHG emissions by avoiding solids dewatering/drying prior to treatment and eliminating biogas flaring and system leakage, and (b) recovering carbon from wastes to replace fossil transportation fuels; and, (7) provides new revenue pathways by producing >1 B gal/y of salable bio-crude and opportunities to recover nutrients and metals worth $30 and $100–280/ dry ton, respectively.

The actual avoided cost (savings) experienced by a waste producer by switching disposal pathways depends on (1) the difference in collection, treatment, and transportation costs between business-as-usual and a new process, and (2) the extent to which any new profits are shared across the supply chain in the form of reduced tipping fees or perhaps even modest feedstock payments. Modeling dynamic scalable feedstock prices is beyond the scope of this report, therefore any savings for waste producers are limited to reductions in tipping fees and feedstock handling costs (i.e., thickening, stabilization, dewatering, storage, pumping, hauling, etc.), which are allocated among the waste producers (WRRFs) and HTL facility for each scenario.

<u>Tipping Fees</u>

In the State of Michigan, all the target feedstocks (sludge, scum, and food waste) are commonly landfilled. Therefore, the tipping fee charged by the HTL facility to waste producers is assumed to be $40/wet short ton ($200/dry short ton at 20% solids) in 2023 dollars, which reflects the current average landfill tipping fee for major active landfills within Wayne County, Michigan (Waste Business Journal (WBJ), 2020), as presented in11.0Appendix D. The tipping fee is considered a credit to the HTL facility (i.e., negative cost). The same disposal fee is used to estimate avoided disposal savings due to decreased residuals production compared to BAU practices. The localized tipping fee is consistent with a national weighted average biosolids disposal cost of $44/wet short ton ($187/dry short ton) in 2019 dollars, as reported in the 2021 HTL SOT (Snowden-Swan *et al.*, 2022). The price is also consistent with the 2014–2020 weighted average biosolids disposal cost (transport + tipping) reported by the state of California for the Bay Area of $52/wet short ton (Bay Area Clean Water Agencies, 2021) and for southern CA of $50/wet short ton (Southern California Alliance of Publicly Owned Treatment Works, 2016).

For broader comparison, the total cost of wastewater and solids treatment and disposal ranges from $100–800 per dry short ton of residual (biosolids) depending on treatment method and disposal pathway, and accounts for 40-50% of the total annual operating costs (Peccia and Westerhoff, 2015). The average cost of primary and secondary treatment, anaerobic digestion, and dewatering is approximately $300/ton. But costs may increase to $800/ton when accounting for hauling, tipping, and the energy cost of incineration, sludge treatment, and handling. The total national financial liability for treating and disposing of the nearly 8 million metric tons per year of biosolids likely exceeds 3.3 billion dollars (Seiple *et al.*, 2020). PFAS regulations could further increase biosolids management costs by 200–600% (CDM Smith, 2020).

<u>Handling Fees</u>

The allocation of costs (and potential savings) related to feedstock handling differ by scenario. In the "Base Case", the HTL plant is coincident with the WRRF but owned and operated by a private entity, imitating the current business relationship between GLWA and NEFCO (NEFCO, 2015). As the feedstocks (sludge solids and scum) occur on-site, they do not require truck transport. Rather, the GLWA pays to pump thickened sludge (4-6% solids) to the HTL facility across the street, where the sludge is further dewatered to increase the solids concentration to 25% prior to conversion to biocrude. The additional dewatering cost of $9/wet short ton is paid by the HTL facility. Side-stream HTL centrate is returned (pumped) to GLWA for treatment at the expense of the WRRF. Handling fees incurred by the WRRF are considered BAU expenses rather than a credit and are not included in avoided disposal costs. Total net feedstock price is equivalent to the tipping fee (credit).

In the “Large Scale” scenario, “on-site” GLWA sludge and scum feedstocks are blended with regional (“off-site”) wastewater solids and non-residential food wastes, also known as Industrial, Institutional, and Commercial (IIC) food waste, from waste producers in the Detroit region. For blended feedstocks, handling costs include the transportation costs (see Section 8.1) and additional waste receiving equipment (see Section 8.2). The blending scenario has four variants (Scenarios A–D), which reflect different amounts of imported waste based on a range of maximum transportation cost limits (see Section 8.2). In all scenarios, the net feedstock price is equivalent to the sum of the tipping fee (credit) and the weighted average off-site waste delivery cost.

5.0 General Scenario Description and Assumptions

5.1 Base Case

The design targets the specific location to the southeast of the GLWA WRRF, adjacent to the Detroit River (Figure 6). For the base case, the plant size is equivalent to that assumed in the previous SOT design: 110 dry short ton/day sludge. The regional resource analysis (see Section 4.0) shows that the GLWA facility can provide enough sludge and thus no other waste from this region is considered for the base case. Consistent with the 2022 SOT, the HTL plant is assumed to be owned and operated by a separate private entity, similar to the current relationship between GLWA and NEFCO (NEFCO, 2015). As described in Section 4.4, most WRRFs pay a waste hauler, landfill, or other receiver to take their sludge and therefore it assumed that the HTL facility is paid to receive GLWA's sludge (i.e., a credit/revenue is applied). Regarding the HTL process design, the PNNL scale-up team identified the HTL solids separation step as a significant risk in operational reliability associated with the historical SOT design. Based on PNNL's bench and engineering scale experimental work, the SOT assumed separation of HTL solids (which consist primarily of ash, char, and some adhered oil/organics) via blow-down and/or filtration directly after HTL essentially at reaction conditions. To address the operational risk of this step, two alternative HTL solid separation methods are considered for the base case analysis, gravity separation and solvent extraction. The detailed designs and assumptions made for these subcases are presented in Section 6.0. It is important to note that these HTL solids separations designs are preliminary and further research is needed to verify feasibility at scale.

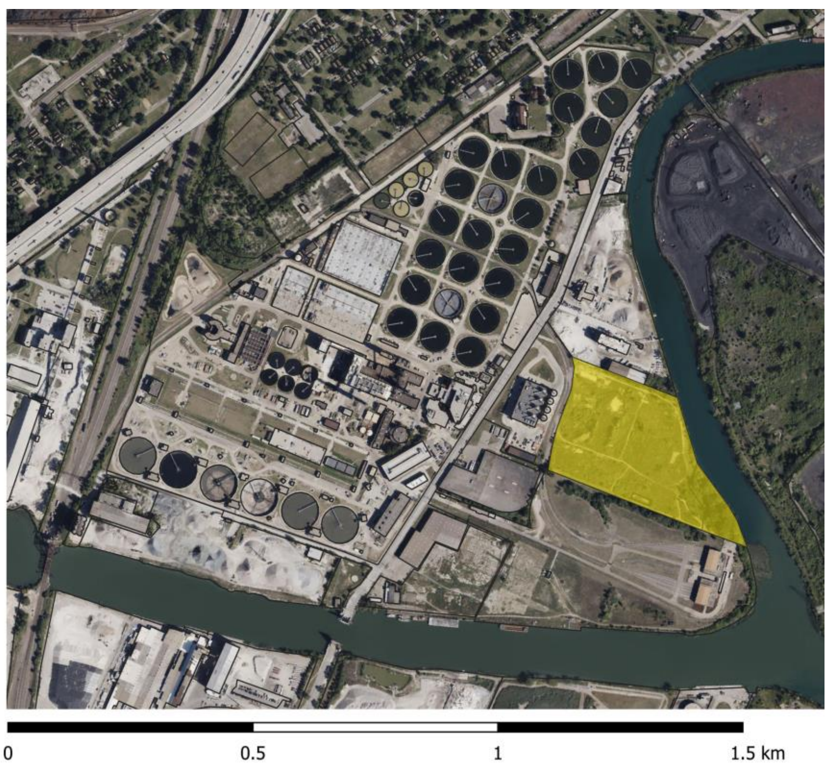


Figure 6. Potential location adjacent to GLWA WRRF for proposed HTL demonstration unit

5.2 Large Scale/Hot Spot Case

One of the key economic drivers for this technology is the plant scale. A chemical plant can experience cost advantages when it increases its scale due to the inverse relationship between the per-unit fixed operating and capital cost and the quantity produced. As with the base case, the land located southeast of the GLWA facility is set as the location to build a centralized HTL plant, but feedstock to this centralized HTL plant includes sludge and scum from GLWA and from other water treatment facilities in the Detroit area as well as IIC non-residential food waste collected from nearby point sources and delivered to the HTL plant gate. Additional capital investment is required for off-site feedstock receiving and handling for the large scale/hot spot case. Note that transportation cost for off-site sludge, scum and food waste highly depends on the size of the waste source and the distance between the points source and the HTL plant. Details can be found in Section 8.2.

5.3 Biocrude Upgrading

In previous analyses, stand-alone plants are considered to convert biocrude to finished fuel blendstocks. As the technologies used for biocrude upgrading are similar to the technologies used in existing petroleum refineries, mainly hydroprocessing, leveraging the existing infrastructure of the petroleum refineries has the potential of reducing the minimum fuel selling price (MFSP) by saving capital expenditures. Figure 7 shows the potential insertion point for co-processing biocrude to a representative petroleum refinery. Here biocrude is co-processed with vacuum gas oil (VGO) in a mild hydrocracker to produce gasoline, diesel-range fuel blendstocks, as well as a high-quality heavy oil fed to the fluid catalytic cracking (FCC) unit to maximize fuel production. From a refiner’s perspective, co-processing biomass-derived intermediates can decarbonize their process and create extra revenue from carbon credits, such as LCFS and RFS. However, co-processing must not incur excessive operating and maintenance cost increases or require expensive capital projects to accommodate changes to the existing petroleum refineries. A BETO funded project titled *Bio Oil Co Processing with Refinery Stream* conducted foundational through applied research to accelerate adoption of biocrude co-processing with petroleum streams in current petroleum refineries via addressing major technical and knowledge gaps and reduce technology uncertainties. Results of these efforts demonstrated the biocrude pretreatment method to mitigate N issues and catalyst deactivation enabling co-processing at hydrocracker and suggested a break-even value (BEV) of biocrude to petroleum refiners as a new feedstock.

As mentioned in Section 5.2, the HTL demonstration plant will be built nearby the GLWA facility. A large-scale petroleum refinery owned by Marathon Petroleum Corp. is located 2 miles away from the proposed HTL demonstration site. Therefore, in this business case study, biocrude co-processing at an existing petroleum refinery is considered for upgrading to finished fuel blendstocks. For simplifying the MFSP evaluation for fuel blendstocks, it is assumed that co-processing will not change the hydrogen and utility consumptions allocated to biocrude upgrading and will stay the same as those of a stand-alone biocrude upgrading plant. Most of the capital investment specified in the stand-alone plant is no longer needed. However, a feeding system and hydrotreating guard bed reactor is still required for biocrude to protect the main hydroprocessing reactors in the petroleum refinery. Details about the mass energy balance and capital investment of a stand-alone biocrude upgrading plant can be found in our previous SOT studies (Snowden-Swan *et al.*, 2022). The estimated MFSP are reported in Section 8.2.

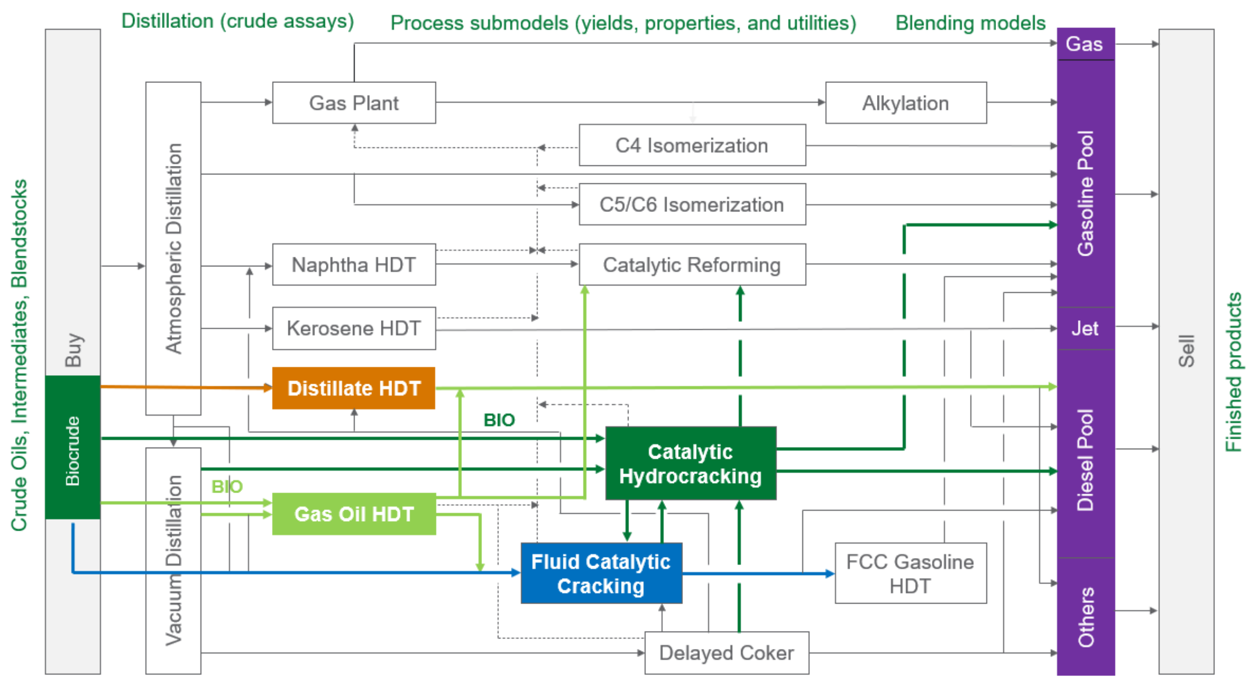


Figure 7. Representative petroleum refinery configuration for co-processing biocrude.

6.0 HTL Process Design

This section describes the process in detail and discusses the key design specifications for equipment sizing and the associated capital costs.

6.1 Sludge Feedstock Dewatering (A100)

Area 100 handles incoming wet waste feedstock. Consistent with the 2022 SOT, the present design assumes that the HTL plant is owned and operated by a separate private entity (while still located near the WRRF). The GLWA pumps thickened sludge to the nearby HTL facility where it is dewatered before the HTL reaction. A simplified process flow diagram for this area is shown in Figure 8 and more detail with the stream information is given in Appendix H. Sludge is dewatered using a centrifuge. Specifically, the 4-6% solid content feed stream from GLWA first enters a sludge storage tank, which can be used to blend different feed sources such as primary and secondary treatment sludge. Then the sludge is mixed with the polymer chemicals to improve dewatering efficiency. The polymer helps to bind the sludge particles, allowing the water to be separated more effectively. The choice of polymer type and dosage depends on the characteristics of the sludge (e.g., its solids content, particle size, and organic content). Typically, onsite testing is required to determine the optimum polymer and dosage rate to achieve maximum dewatering efficiency while minimizing chemical usage and costs. A centrifuge is selected as the dewatering equipment here due to its ability to achieve high cake solid content (typically between 18% and 35%), operate continuously for large-scale plants, as well as consume relatively lower energy and polymer with low maintenance. The design includes two centrifuges online and one on standby, with a single centrifuge capacity of 5000 lb/hr dry solid to meet the 110 dry ton per day scale. The centrifuge will be mounted on an elevated platform (on the third floor) and the dewatered sludge directly drop into the cake hoppers (the second floor), and then to the feed pumps to HTL facility (on ground). A sludge grinder is located up-stream of the centrifuge in order to macerate any large particles in the sludge before it enters the centrifuge. Forced ventilation is required for odor control and toxic gas removal, which uses a wet fan and a wet scrubber with solvent. Table 5 summarizes the key design specifications for the polymer preparation station, storage tank, cake hopper and odor control system.

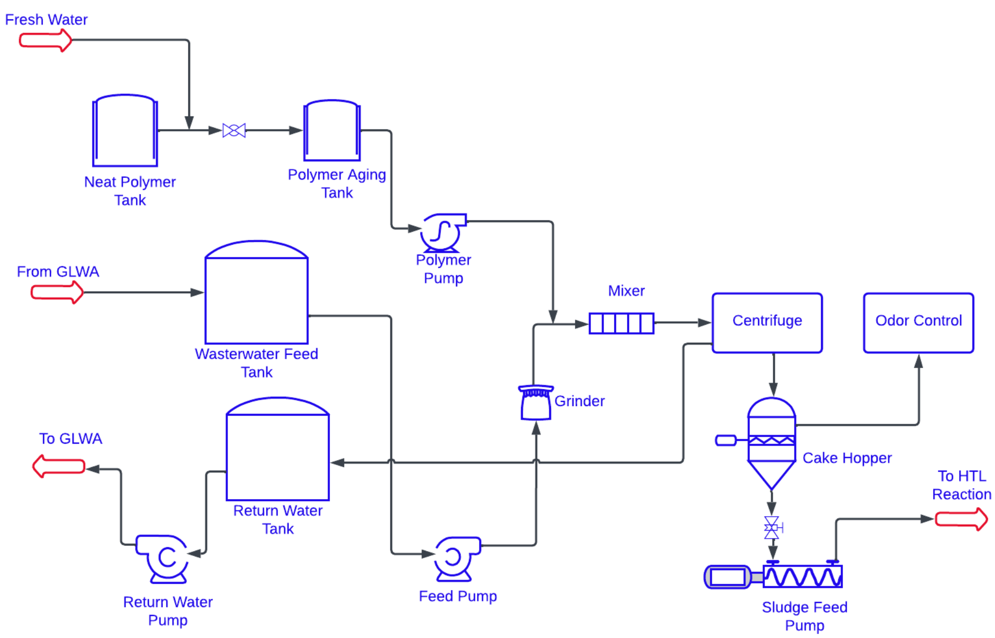


Figure 8. Simplified flow diagram of the feedstock dewatering and storage system.

Table 5. Key design specifications for sludge dewatering.

Variables	Specifications
Polymer dose	50 lb active polymer per dry ton sludge
Aging polymer concentration	5%
Polymer storage tank design residence time	5 days
Aging polymer tanks design residence time	2.5 hrs
Piping/tank material	PVC
Average feed solid percentage	4.50%
Dewatered sludge solid percentage	25%
Feed/return water tank design resident time	5 days
Cake hopper volume utilization	60%
Cake hopper design resident time	6.7 hrs
Odor control ventilation rate	20,000 ft^3/min

6.2 HTL Reaction and Biocrude Production (A200)

6.2.1 Low Pressure Feed Preheating

In prior SOT studies, a sludge with a 25% solid content was conveyed to the reactor at a pressure of approximately 2,600 psig. This process involved heating the feed sludge from 60°F to 650°F by recovering heat from the HTL reactor effluent and using external natural gas sources. The results of these SOT investigations revealed a significant challenge in the design of the initial heat exchanger due to the high viscosity of the sludge and the reduced heat transfer coefficient at lower temperatures. This design also raised concerns about potential operational difficulties when scaling up to a commercial HTL plant, primarily stemming from potential fouling issues within the system. Like many other biowaste processes, the formation of salt precipitates is common at elevated temperatures. In this scenario, the presence of CO_2 exacerbates the challenge, as carbonates are notably insoluble at higher temperatures. This type of fouling can also decrease the heat transfer coefficient. If fouling is persistent, labor-intensive procedures such as disassembly, cleaning, and maintenance of the high-pressure, high-temperature equipment may be required, leading to reduced streaming factors. Frequent cooling and reheating the heat exchangers for maintenance and cleaning could shorten their life from the temperature cycling and increase higher potential for leaks. The factors led to the search for alternative means to heat the sludge.

The new design presented in this study draws inspiration from the practice of preheating sludge through direct steam injection in the Cambi™ process, aiming to mitigate or minimize fouling problems within the heat exchangers. The injection of steam utilizes the latent heat to rapidly warm the cold and viscous feed sludge, thereby helping to overcome the heat transfer rate limitations and fouling that result in conventional heat exchanges, where heat is transferred through pipes or tubing walls. Additionally, the equipment used for preheating feedstocks with direct heating can be more cost-effective compared to the heat exchangers used in previous SOT designs. Figure 9 shows the simplified process flow diagram for sludge preheating and HTL reaction. Appendix H provides the detailed process flow diagram (PFD) and stream information.

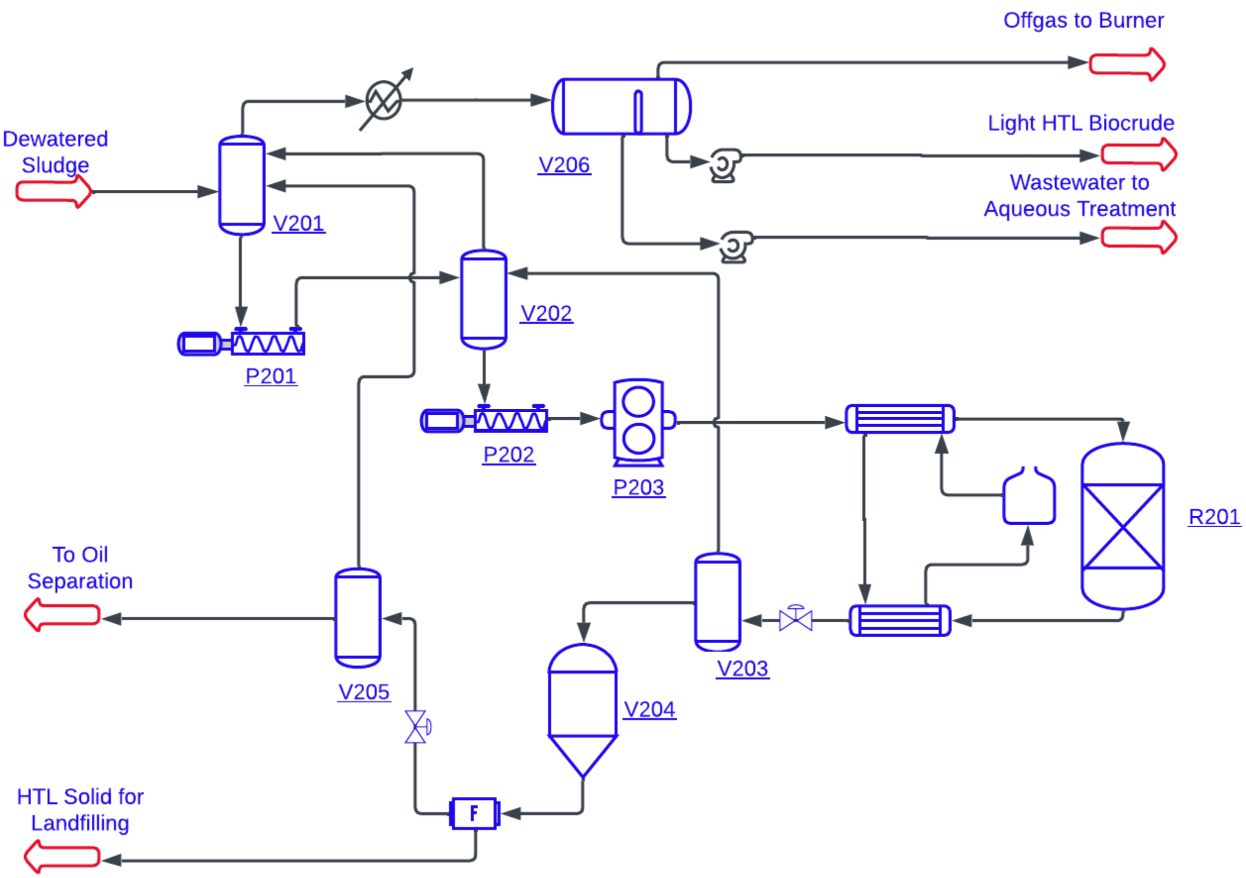


Figure 9. Simplified flow diagram of the HTL reaction and biocrude production via gravity separation.

As illustrated in Figure 9, this design employs a two-stage flash heating process. Specifically, the high-pressure, high-temperature HTL reactor (R201) effluent undergoes high-pressure and low-pressure hot separations before transitioning to a lower-temperature and lower-pressure phase. The vapor streams generated during these two hot separations are collectively referred to as "flash steam." The composition of the flash steam varies depending on the pressure at which the hot separations are conducted. The operating pressures for these two hot separators are carefully chosen to optimize overall heat recovery from the flash steam while also ensuring that the feed tank temperature remains below 340°F. This temperature threshold is critical because it prevents hydrothermal carbonization (a cooking process) from occurring. At temperatures exceeding this threshold, sludge can transform into carbon or solid biocoal, potentially leading to a reduction in biocrude yield. To rigorously model the flash step, the modeled biocrude components have been carefully refined to match the elemental balance as well as distillation curve to the experimental data. The full list of model compounds is given in Appendix I. Figure 10 shows the model's biocrude distillation curve compared to the simulated distillation (SIMDIS) data from the experimental biocrude sample.

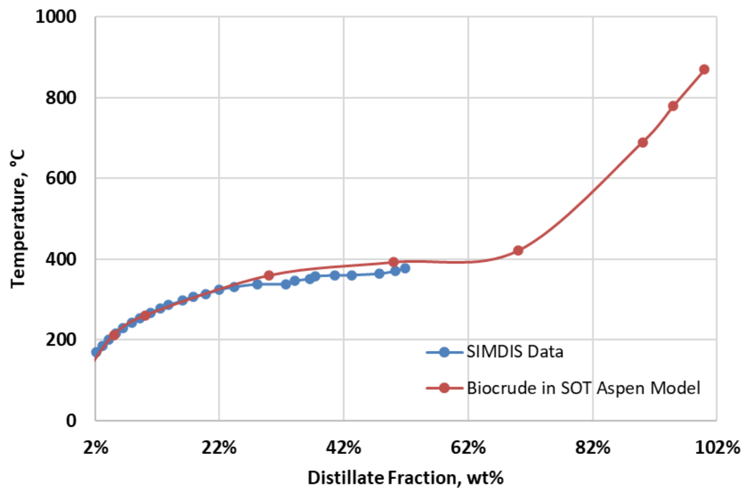


Figure 10. the modeled distillation curve of HTL biocrude against the tested SIMDIS results.

The first flashing step drops the pressure from 2,600 psig to 240 psig, with 11% of the water is converted to steam with some HTL gas and light biocrude distillates. Flash vapor and liquid are separated in a high-pressure flash vessel (V203) and the flash steam/vapor is routed to a second feed preheat tank (V-202). Note that the pressure of the feed preheat tank must be less than the high-pressure (HP) hot separator to maintain steam flow. As mentioned before, the pressure of HP flash vessel also controls how hot its contents can be heated, as the maximum liquid temperature is set by the vapor-liquid equilibrium of water. Therefore, for maximum heat recovery, the pressure of second feed preheat tank should be set as close to the pressure of high-pressure flash vessel as possible, while still maintaining the target steam flow rate. The minimum pressure difference possible between these two would be the frictional pressure drop in the overhead line connecting them, including the pressure drop from the steam injection nozzle in second feed preheat tank and the pressure required to overcome the liquid level head pressure in second feed preheat tank.

The second flashing process occurs from dropping the pressure of the liquid bottoms from the HP flash vessel across another control valve. The model predicts that 18% of the liquid water is converted into steam by dropping the pressure from 240 psig to 35 psig. The flash steam flows overhead from the low-pressure (LP) flash vessel (V203) and is then injected into the first preheat (FP) tank (V201) to heat the cold sludge stream from ambient temperature to 220°F. The maximum temperature achievable in the FP tank is set by the operating pressure and the vapor-liquid equilibrium line of water. Operating pressure must be carefully selected because a higher pressure in the FP tank results in a higher pressure in the HP flash vessel, which limits the heat recovery, as previously explained. Therefore, the operating pressures of the FP tank and the second preheat (SP) tank must be optimized together to achieve optimal heat recovery for the overall system. It is expected that the pressure letdown steps will be erosive to the valves due to the operating conditions and the presence of solids (primarily ash and some char) in the stream. To address this risk, duplicate high pressure letdown valves are included in the design to allow for valve maintenance and replacement during operations. Note that this flash-heating process has not been tested in the laboratory with actual HTL process streams. To account for this key performance uncertainties around this step are investigated in the sensitivity and uncertainty analyses (Section 7.5) including the volatility of organic components in the four steam flashing drums and the biocrude yield, which may be impacted by the recycling organic components from steam flashing drums to the reactor.

6.2.2 High Pressure Feed Heating and HTL

The preheated feed is further heated to the HTL reaction temperature via heat exchange (E201) with 700°F hot oil. As shown in Figure 9, an oil loop is used to transfer heat from the HTL effluent stream to the cold sludge feed stream. Specifically, the return heating oil from E201 is pumped to E202 to heat to 630 °F and then further heat to 700 °F via furnace burning natural gas. Considering the fouling issue on the hot surface, both spare heat exchangers are considered to take one set equipment offline for cleaning and the detailed is shown in the equipment list (Appendix F). After reaching the HTL temperature and pressure, the sludge feedstock enters to HTL reactor. The reactor was sized to allow for the necessary reaction time of 10 min. The reactor diameter was set to 4 ft to maintain the vessel wall thickness to manageable levels and to minimize back mixing. However, if should be noted that the reactor dimensions have not been optimized for economics. A total length of 40 ft would be required to achieve the 10 min residence time target. Due to the very corrosive nature of the HTL process at the subcritical condition, a SS316 would be required. The vessel walls are calculated to be a minimum of 4.5" thick. Following the HTL reactor there is a vapor/liquid separator drum. The vapor/liquid separator drum is necessary to generate a pure liquid stream for the high-pressure letdown station, as the letdown valve cannot accommodate gas-liquid flow at the inlet. The liquid volume at the bottom of the vapor/liquid separator also provides additional time at temperature for the HTL reactions to complete.

6.2.3 HTL Phase Separations

The cooled HTL effluent stream after the two-stage flash process consists primarily of water, biocrude components, water soluble organics, and solids. Previous SOTs have assumed solids are blown down directly following the HTL reactor (at conditions) based on PNNL's experimental system. However, significant engineering challenges discuss previously make scaling of this method very challenging at the commercial scale. To reduce this risk two alternative solids separation methods were investigated, gravity separation and filtration at elevated temperature, and solvent extraction. For the gravity separation scenario, depicted in Figure 11, the use of elevated temperature and pressure is desirable to prevent water/oil/solid emulsion formation. We have not yet tested the solids settling method, however, based on the experimental team's experience and engineering judgement, it is assumed that HTL solid can precipitate and settle at elevated pressure and temperature (240 psig and 300 °F) in 30 minutes and then be filtered out via an online filter. As shown in Figure 9, a settling tank and online filter are located between the two-stage flash tanks. Future testing is needed to verify the feasibility and understand the limitations of this method.

Solvent extraction was also investigated for separation of the HTL solid phase (Uriah Kilgore *et al.*, 2024). From batch testing, this investigation showed that successful biocrude separation can be achieved using operating parameters close to those used for the commercial extraction of petroleum from tar sands. It was also found that with solvents, biocrude associated with the blowdown solids was recovered. The extracted blowdown solids settled faster and dewatered better than those generated in the high temperature high pressure blowdown approach. Figure 11 shows the simplified PFD for the solvent extraction process while Appendix H shows the detailed flow diagram with stream information. The HTL effluent after two-stage flash is further cooled to 140 °F and then mixed with solvent at the assumed solvent/HTL reaction effluent at 0.5. While toluene was modeled for the process, the team's target solvent is reformate from the catalytic reformer of petroleum refinery to leverage the lower price, availability of the reformate as a solvent. After well-mixing, the mixture flows to the first stage settler (V201) with enough residence time for complete oil-aqueous separation. Then the upper oil layer is heated via an economizer (E202) to recover the solvent at the top of the distillation column (T201). The biocrude will be obtained at the distillation column bottom. Note that 3% of the solvent will be left with the biocrude. So, a small portion of solvent stream is added to keep the solvent/HTL effluent ratio at 0.5, and the solvent makeup is combined with recycled solvent from the distillation to mix with the aqueous stream from the first-stage settler (V201) for feeding to the second-stage settler (V202). After the second-stage separation, the aqueous phase goes through a static cyclone (C201) for recovering oil if any and HTL solid will be filtered out via an online filter (F201). Table 6 summarizes the key design specifications for the two-stage flash and the two HTL solid separation methods. Note that much of this design is based on engineering judgement and performance is based on predictions from the process model. Experimental work with a continuous test system currently in progress by the PNNL team and additional data is expected to be available for the subsequent publications.

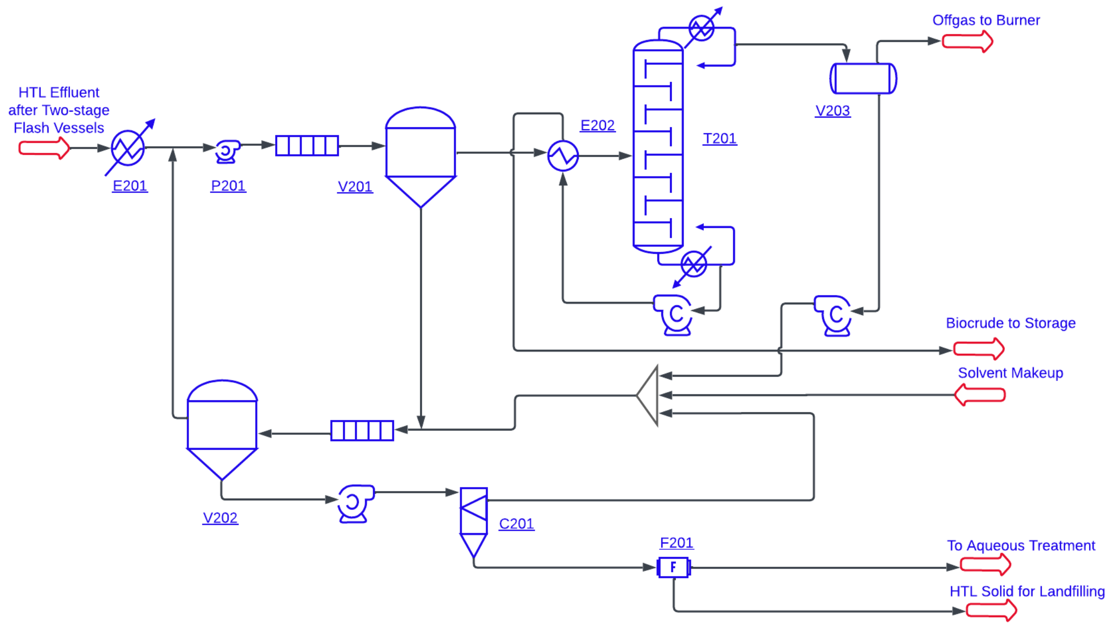


Figure 11. Simplified flow diagram of HTL solid separation via two stage solvent extraction.

Table 6. Summarized the key design specifications for HTL reaction and Product Separation.

Variable	Specifications
First preheats (FP) tank condition	355°F/250 psig
FFP tank resident time	30 min
Second preheat (SP) tank condition	200°F/10 psig
FFP tank resident time	30 min
High pressure (HP) flash vessel condition	398°F/260 psig
Low pressure (LP) flash vessel condition	275°F/30 psig
HTL solid settling time	30 min
High pressure letdown lifetime	6 months
Solvent/ HTL effluent ratio	0.5
Solvent recovery rate*	90%

*7% of solvent remains with the biocrude fraction and will recycle from the refinery to the HTL plant

6.3 HTL Aqueous Treatment (A300)

In prior SOTs, ammonia stripping was chosen as the base method for treating HTL aqueous waste, although various advanced HTL aqueous treatment techniques have also been explored. In this current study, ammonia stripping is retained as a well-established pre-treatment step before the effluent is returned to publicly owned WRRF. The HTL plant is charged a fee by the WRRF for excess levels of NH_3 and chemical oxygen demand (COD) that remain in this stream. Figure 12 provides a simplified process flow diagram illustrating this approach. Specifically, the separated aqueous phase is sent to a series of treatment steps before recycling back to the WRRF. First, it is treated with quicklime to raise the pH to ~11 in V301 and V302 and then stripped with air to remove ammonia and volatile organics (VOCs) in the aqueous stream. The removed ammonia and VOCs are destroyed in a thermal oxidizer (R301) with the help of natural gas and catalyst. At the same time, the stripper (T301) bottom is sending to the WRRF for COD treatment.

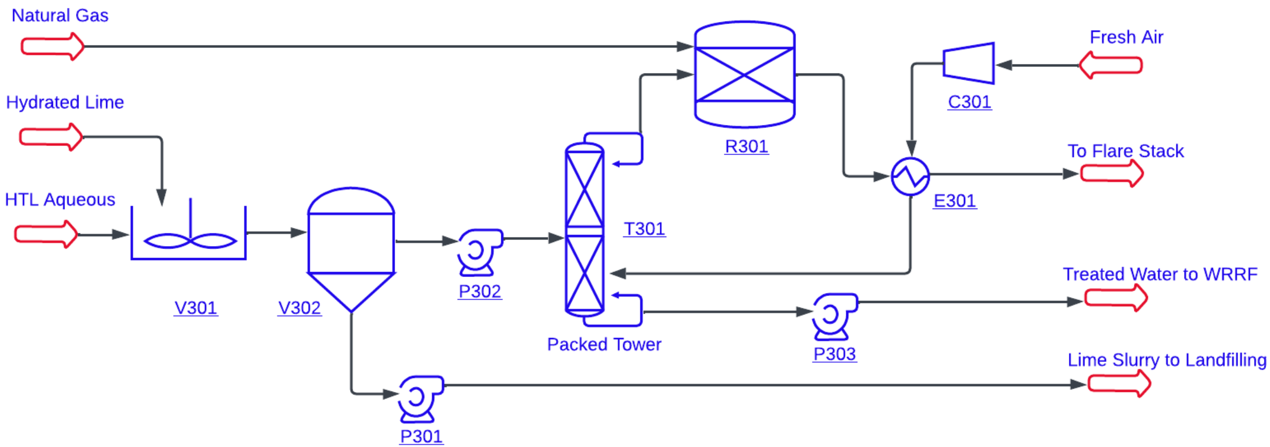


Figure 12. Simplified flow diagram of the HTL aqueous treatment via ammonia stripping.

Table 7. Summarized the key design specifications.

Variables	Specifications
quicklime consumption	31 lb/ton HTL aqueous phase
Lime clarifier resident time	2 hours
NH3 removal efficiency via stripper	98%
THROX temperature	662 °F

6.4 Balance of Plant (A400)

This portion of the plant provides bulk storage for process chemicals and the biocrude product as well as cooling water, flare, and boiler system. The chemicals stored in this area include polymer, boiler/cooling tower chemicals, and quicklime. The storage tank for biocrude product is designed with 3 days of production capacity. The design capacity of the cooling tower system is 30 gallon per minute with a 50% overdesign. The flare system is designed with the maximum gas discharge flow rate of 2000 lb/hr in case of an emergency. A packed boiler with a boiler flowrate of 10,000 lb/hr is included for start-up or abnormal operation conditions.

7.0 Economics and Greenhouse Gas Assessment for Base Case

In this assessment TEA and LCA were conducted based on detailed process design, simulation, and cost estimation. The results presented in this section can be used: 1) to provide an initial indication of the viability of HTL-based fuels within the market, 2) as the CO_2 footprint basis to estimate potential incentives from low-carbon fuel policy support, and 3) to guide future R&D efforts toward improved cost and sustainability performance and operational reliability. An Excel-based cost estimation tool is provided along with this report that allows users[1] to conduct preliminary economic assessments of HTL with their own site-specific economic assumptions and feedstock data.

The total capital investment (TCI) for the HTL plant is computed from the total equipment cost. Variable and fixed operating costs are determined from the mass and heat balance. With these costs, discounted cash flow analysis is conducted to determine the minimum fuel selling price (MFSP) of the biocrude and the finish fuel required to obtain a zero net present value (NPV) with a 10% of finite internal rate of return. MFSPs are presented to maintain consistency with previous BETO analyses. Additional economic metrics more broadly used by industry, including internal rate of return after tax (IRR) and NPV, are also evaluated. These are estimated assuming current marketplace prices for biocrude intermediate and final fuel to provide direct plant profitability information for a specific site application. A cumulative sustainable fuel credit range (detailed in Section 3.0) of $0.5 to $3.5/GGE is considered for calculating IRR and NPV to give policymakers and stakeholders a sense of the magnitude of incentive required to make the HTL plant economically viable in a modeled market scenario. Lastly, LCA is conducted to calculate the supply chain GHG emissions using the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model developed by U.S. DOE Argonne National Laboratory.

7.1 Total Capital Investment

Section 6.0 of this report shows the details of each process area and how the purchased cost of the equipment was determined. Appendix F contains the complete equipment list for the HTL plant. The next step is to determine the installed cost of each piece of equipment by performing a detailed study of accessories required to install the necessary foundation and devices and make the plant operational (e.g., foundation, piping, instruments, wiring, insulation, and paint). Previous SOT studies used an installation factor approach to estimate the installed equipment cost. However, installation factors from the literature can vary widely (Garrett, 2012; Peters and Timmerhaus, 2018) and can be inaccurate due to the uniqueness of each process and lack of details/specificity. Here the plant design and Aspen Plus process model output, including the complete material, heat, utilities and mass balances, PFDs, full equipment list with detailed sizing and specifications, and key technology performance measures, is used to directly estimate the purchased equipment and installed equipment costs via Aspen Capital Cost Estimator (ACCE), providing a more rigorous approach than the simplified installed factor method. Figure 13 shows the process equipment cost estimation procurement steps carried out by ACCE. For the non-quoted equipment, sizing is conducted via the built-in ACCE volumetric component. The detailed Piping & Instrument Diagram created by ACCE provides the associated cost with installed piping and instrument for this equipment. The piping length is estimated based on the plant equipment plot. The built-in civil and steel volumetric model is used to estimate the associated cost for the necessary foundation and platform. Budgetary quotes were obtained for the non-standard equipment. The installation cost for such packages can be relatively low

[1] Note: The business case study includes assumptions and is specific to one conceptual application and should not be used by stakeholders as a detailed design. Cost estimates are based on our approach, and stakeholders are advised to create their own estimates based on the fidelity needed for decision making.

because most of the engineering is already included in the quoted price. Additionally, equipment designed as a prefabricated skid generally has a lower construction cost. Also, components that are more highly machined and have higher-quality metallurgy tend to be more expensive per unit mass and therefore have a lower installation factor as a function of purchase price compared with a less sophisticated component.

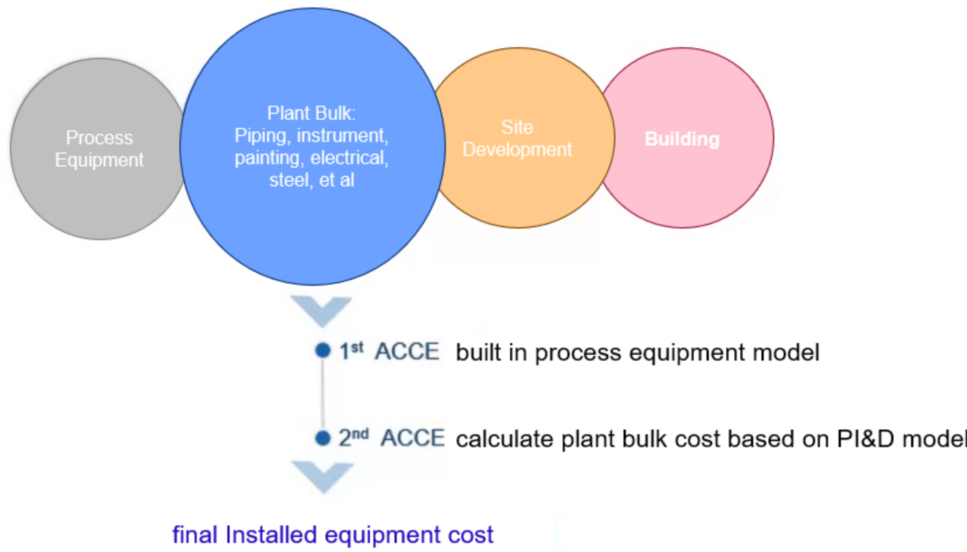


Figure 13. The process equipment cost estimation procurement steps by ACCE.

To the installed equipment cost (determined in the year of interest) several other direct and indirect costs are added to determine the total capital investment (TCI). Specifically, site development and warehouse costs are based on the installed equipment costs and are considered part of the total direct cost (TDC). Project contingency, field expenses, home-office engineering and construction activities, and other costs related to construction are computed relative to the TDC and give the fixed capital investment (FCI) when summed. The sum of FCI and the working capital for the project is the TCI. Appendix B lists the direct and indirect cost factor values applied in this work, which are consistent with wet waste HTL SOT studies and other BETO , with the exception of the factor for “additional piping”. The additional piping cost here refers to the cost of piping that connects the process equipment to storage, utilities, piping racks, etc. The detailed ACCE results for the HTL plant show that the additional piping cost is about 14% of the total installed equipment cost, which is significantly higher than the standard BETO assumption of 4.5% (Snowden-Swan *et al.*, 2017, 2022b, 2022a) .

Table 8 summarizes the total installed equipment cost and illustrates the application of factors to obtain the TCI. The detailed equipment list with breakdown of bare and installed costs is provided in Appendix F. The TCI increases about $11 MM if using solvent extraction instead of gravity separation, due to a more complex process needed for the former. The estimated TCI from the current analysis is about three times that of the 2022 SOT. This is due to several adjustments and updates in the equipment and costing process: 1) additional piping, as mentioned in previous paragraph, 2) equipment redundancies were included to decrease operational risk, 3) the estimated capital cost for the sludge dewatering section is about 5 times that estimated for the 2022 SOT, as we have implemented a more detailed equipment list based on the current operational wastewater treatment plant, 4) the HTL solid separation process scenarios via settling and filtration and solvent extraction were carefully designed to include (see Section 6.0), and 5) installment cost for piping, instrument, foundation, and steel structure are included, which can explain a higher overall installed factor and Lang factor for this work.

Table 8. The detailed poject cost summary for HTL plant

	2022 SOT		Base Case 1 Gravity Separation		Base Case 2 Solvent Extraction	
					Capital Costs, $ million	
Process Area	Purchased	Installed	Purchased	Installed	Purchased	Installed
Sludge feedstock dewatering	0.83	1.51	3.65	8.00	3.65	8.00
HTL biocrude reaction	8.66	12.42	13.48	26.33	14.65	31.08
HTL aqueous treatment	0.86	2.13	1.71	3.80	1.71	3.80
Balance of plant	0.36	0.56	0.82	3.12	0.82	3.12
Totals	10.71	16.62	19.66	41.25	20.83	46.00
Buildings		0.66		1.65		1.84
Site development		1.66		8.25		9.20
Additional piping		0.65		4.35		5.04
Total Direct Cost (TDC)		**19.60**		**55.50**		**62.08**
Prorateable expenses		1.96		5.55		6.21
Field expenses		3.92		5.55		12.42
Home office & construction cost		1.96		11.10		6.21
Project continency		1.96		5.55		6.21
Other costs (startup, permits, etc.)		1.96		5.55		6.21
Total Indirect Cost (TIC)		11.76		33.30		37.25
Fixed Capital Investment (FCI)		31.36		88.80		99.33
Land		0.09		0.09		0.09
Working capital		1.57		4.44		4.97
Total Capital Investment (TCI)		33.02		93.33		104.38
Lang Factor (FCI/purchased equip cost)		**2.93**		**4.52**		**4.77**

7.2 Process Variable and Fixed Operating Costs

Process variable operating costs include the cost associated with raw materials, chemicals, utilities, waste handling charges, and by-product credits, which are subject to change when the plant loads and other variables change. Waste disposal includes a fee of $0.561/lb for excess NH3 (> 25 mg/L) and $0.13/lb for excess COD (> 500 mg/L), equivalent to that assumed for the 2022 SOT. The mass and utilities balance data are obtained from the Aspen Plus model. Appendix A summarizes the quantities of raw materials, chemical, utility per GEE biocrude. Quantities of raw materials used, and wastes produced were determined using the Aspen material balance. Table 9 summarizes the variable costs on a per-year and per-GGE basis. The solvent extraction scenario has a higher cost than the gravity separation scenario mainly due to the solvent consumption ($0.08/GGE) and natural gas for the solvent recovery distillation column reboiler ($0.04/GEE). Overall, the conversion cost without avoided sludge disposal cost is around $1.3-1.4/GGE for both solid separation methods.

Table 9. Variable operating costs for HTL plant.

$/GGE biocrude ($ million/yr)	Gravity Separation	Solvent Extraction
Avoided sludge disposal cost	-1.75 (-6.7)	-1.64 (-6.7)
Natural gas	0.04(0.2)	0.08 (0.3)
Chemicals	0.26 (1.0)	0.34 (1.4)
Electricity	0.06 (0.2)	0.06 (0.3)
Waste Disposal	0.97 (3.7)	0.93 (3.8)
Conversion cost, $/gal biocrude	1.44	1.57
Conversion cost, $/GGE biocrude	1.33	1.42

The fixed operating costs include labor and various overhead items using the same assumptions used the previous SOT studies. A 90% labor burden is applied to the salary total and covers items such as safety, general engineering, general plant maintenance, payroll overhead (including benefits), plant security, janitorial and similar services, phone, light, heat, and plant communications. The 90% estimate is the median of the general overhead range suggested in the 2016 PEP Yearbook produced by SRI Consulting. Please note that the fixed labor cost per GGE biocrude produced is very sensitive to plant scale, as the number of operators does not increase with plant scale linearly. Therefore, a noticeable decrease in the fixed labor cost per GGE biocrude can be seen in the large-scale case detailed in Section 8.2.

Table 10. Fixed operating costs for the HTL plant.

Fixed Operating Costs	2020 salary	# required	Cost	MM$/yr	cents/GGE
Plant Manager	178,304	1	178,304		
Plant Engineer	84,907	1	84,907		
Maintenance Supervisor	69,138	1	69,138		
Lab Manager	67,925	1	67,925		
Shift Supervisor	58,222	3	174,665		
Lab Technician	48,518	1	48,518		
Maintenance Tech	48,518	1	48,518		
Shift Operators	58,222	4	232,887		
Yard Employees	33,963	1	33,963		
Clerks & Secretaries	43,666	1	43,666		
Total Salaries				0.98	25.64
Labor Burden				0.88	23.08
		Other Overhead			
Maintenance				2.46	64.09
Insurance & Taxes				0.62	16.22
Total fixed operating costs				4.94	129.04

7.3 Minimum Fuel Selling Price of the Biocrude

Figure 14 illustrates the modeled MFSP of the biocrude and cost allocation for the two HTL solid separation methods considered. The plant scale (110 dry ton sludge/day) and avoided sludge disposal cost ($187/dry ton) is kept consistent with SOT studies. With the detailed process design and capital cost estimation, the modeled MFSPs of the biocrude for the gravity separation and solvent extraction scenarios are $4.11/GGE and $4.37/GGE respectively. Note these values are for the intermediate biocrude product from the HTL plant and do not include the cost of hydroprocessing to produce finished fuel blendstocks. Compared to gravity separation, solvent extraction adds two-stage solvent extraction steps as well as a solvent recovery distillation column, which requires more capital expense, extra chemicals and energy consumptions. However, solvent extraction can more efficiently separate the biocrude from the HTL solids and aqueous phase, which results in a 3% higher biocrude yield compared with HTL separation via settling and oil-aqueous separation via gravity. Even with the benefit of a higher biocrude yield, the added capital and operating cost (natural gas, solvent, and electricity) for the solvent extraction case more than offsets this benefit, contributing about $0.11/GGE and $0.04/GGE to the MFSP of the biocrude, respectively. Note that the current solvent extraction model heavily relies on the built-in thermodynamic package in Aspen Plus and the model will be updated and validated with additional experimental data when available.

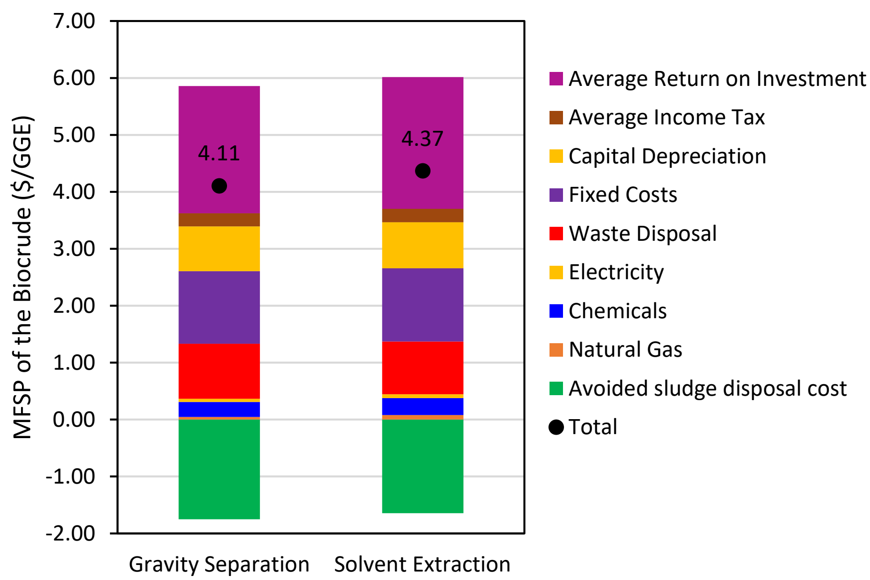


Figure 14. HTL plant (110 dry ton/day sludge) MFSP of the biocrude and cost allocation for base case with gravity separation vs. solvent extraction for HTL solids separation.

The HTL biocrude intermediate is sent to a nearby petroleum refinery to be co-processed with petroleum intermediates and upgraded to finished hydrocarbon fuel blendstocks, as detailed in Section 5.3. Even though the co-processing approach can leverage existing infrastructure in the petroleum refinery, additional capital investment of 2.43 MM$ is required for the biocrude feeding system and the hydrotreater guard bed (Jiang *et al.*, 2020). A discounted cash flow approach was conducted to estimate the MFSP of the finished hydrocarbon fuels from the MFSP of biocrude and additional capital and operating cost associated with biocrude upgrading at an existing petroleum refinery. The estimated biocrude upgrading cost is $0.79/GGE. Therefore, the MFSP of the finished hydrocarbon fuels is $4.9/GGE and $5.16, respectively for biocrude produced from the gravity separation, and solvent extraction scenarios. Table 11 lists the key performance measures of the HTL plant from sludge to biocrude, upgrading step from biocrude to fuel, and the combined process from sludge to fuel for the gravity separation scenario.

Table 11. Key performance measures of wet waste HTL process for finished fuel blendstock production.

Performance Measures	Sludge to Biocrude	Biocrude to Fuel	Sludge to Fuel
Fuel yield (AFDW)	44.53	78.45	34.93
Gas yield (AFDW)	15.73	11.91	
Aqueous yield (AFDW)	27.56	9.64	
Solid yield (AFDW)	12.18		
Carbon efficiency w/o NG (%)	66.58	88.47	58.91
Carbon efficiency w/ NG (%)	64.21	83.76	53.78
Thermal efficiency w/ NG (%, LHV)	72.13	82.74	59.68
Thermal efficiency w/ NG (%, HHV)	69.87	83.15	58.10
Electricity consumption (kWh/GGE)	0.75	0.41	1.22
Natural gas consumption (scf/GGE)	11.48	10.54	22.89

7.4 Economic Performance Under Marketplace

7.4.1 Potential Biocrude Selling Price to Petroleum Refinery for Co-processing

In the NPV calculation, the biocrude selling price is fixed to \$2.23/GGE, the estimated break-even value (BEV) of biocrude to petroleum refiner based on the refinery impact analysis (Jiang *et al.*, 2020) conducted for co-processing biocrude with VGO at a representative petroleum refinery as shown in Figure 5.3.1. In the refinery impact analysis (Jiang *et al.*, 2023), a full refinery linear programming model was developed in Aspen Process Industry Modeling Systems (PIMS), a widely used software in the petrochemical industry, to evaluate the potential economic impacts on adding biocrude to an existing refinery as a new feedstock from changes in hydrogen and utility consumption, conversion, yields, product qualities, etc. The linear programing model was built based on lab scale co-processing experimental data using real petroleum and biomass(Jiang *et al.*, 2020) intermediates collected from the BETO funded project described in Section 5.4, refinery configuration and fuel market demand from U.S. EIA database, ASTM fuel property specifications, and prices of crude oil and finished fuels from OPIS database. BEV is the key model output, which represents the targeting selling price of biocrude to a petroleum refinery that would allow the petroleum refinery to maintain at least the same gross margin. A biocrude candidate of better quality with more positive and less negative impacts on the operation of petroleum refineries will have a higher BEV to petroleum refiners. The approach of developing the linear programing model for refinery impact analysis can be found in our previous publication (Jiang, *et al.*, 2023).

7.4.2 NPV and IRR with Potential Sustainable Fuel Credits

Figure 15 shows the NPV and the IRR after tax with the potential biocrude selling price to refineries at \$2.23/GGE and the cumulative sustainable credits (\$0.5-3.5/GGE, see Section 3.4) from the current federal and state policies. Specifically, NPV is a measure of the total profit accounting for the internal rate of return at 10% in present value, over the process plant lifetime, which is set to be 30 years. IRR is a measure of the maximum interest rate allowed for the process, allowing a NPV of 0 at the end of the process plant lifetime. A higher internal rate of return indicates the project investment is more profitable or can generate a higher return on investment. As shown, a sustainable fuel credit of \$1.8/GEE or higher is required to make a 110 dry ton/day HTL plant economically successful as a business case. Also, when the sustainable fuel credits drop below $1.00/GGE, the IRR (NPV = 0) will be lower than 6%.

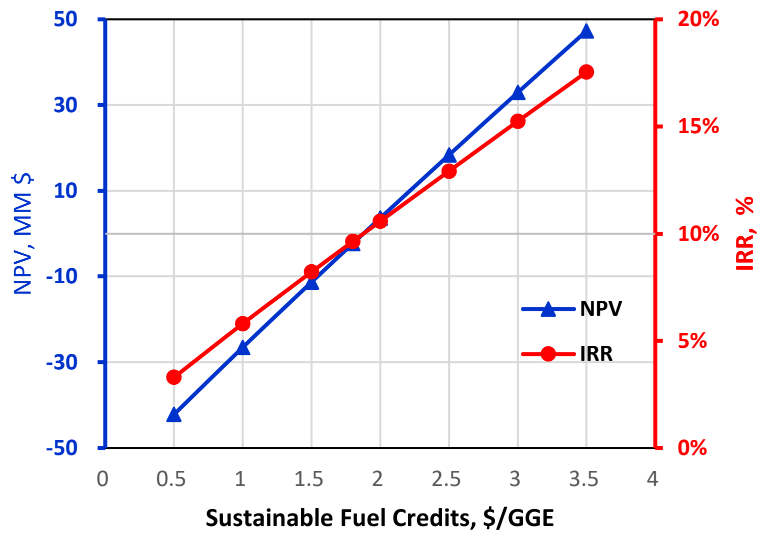


Figure 15. NPV and IRR with the potential sustainable fuel credits from the current federal and state policies.

7.5 Sensitivity and Uncertainty Analyses

Sensitivity and uncertainty analyses were conducted to evaluate the individual and combined impacts from feedstock composition, process model accuracy, pricing and economic assumptions, equipment sizing and cost estimation on the economic performance of the base case HTL plant. The sensitivity study is conducted by changing the value of one variable at a time, which is a powerful method to quantify the impacts from each individual component on the key performance, economic, and environmental measures of the technology. However, it cannot systematically quantify the combined impacts from a large set of variables on key technology measures, as the impact from each variable are not linearly additive. Stochastic simulation, also called uncertainty quantification, can fill in the gaps in sensitivity study by providing a range and the likelihood of possible values of key technology measures when considering uncertainties from all variables simultaneously. In uncertainty quantification, Monte Carlo sampling method is used to draw semi-random values of variables with pre-determined probability distribution and use it as the inputs to complete one model run during each trail. This step is repeated a number of times until the model is converged with a certain confidence interval. Details about Monte Carlo simulation can be found in our previous publications (Li *et al.*, 2021; Jiang *et al.*, 2023a; Jiang *et al.*, 2023). The complete list of variables included in both sensitivity and uncertainty analyses can be found in Appendix E.

As stated in Section 4.4, feedstock credits can be potentially received from WRRE facilities due to the large biosolid disposal cost associated with current practices such as landfilling, incineration, et al. The assumed avoided sludge disposal cost at -$40/wet ton in the base case is consistent with the current average landfill tipping fee ($39.7/wet ton) for major active landfills within Wayne County, Michigan, although it is slightly lower than the national weighted average biosolids disposal cost ($44/wet ton) and the weighted average biosolids disposal cost for the Bay area ($52/wet ton) and southern California ($50/wet ton). Also, the biosolid disposal cost of the current practice at GLWA is about $80/wet ton (70% moisture) (Fonoll-Almansa, 2023). Figure 16 shows the impact of feedstock credits on MFSP of the biocrude for the cases with gravity separation and solvent extraction. For both cases, the biocrude MFSP can linearly decrease by approximately $0.10/GGE as feedstock credit increases by $10/dry ton.

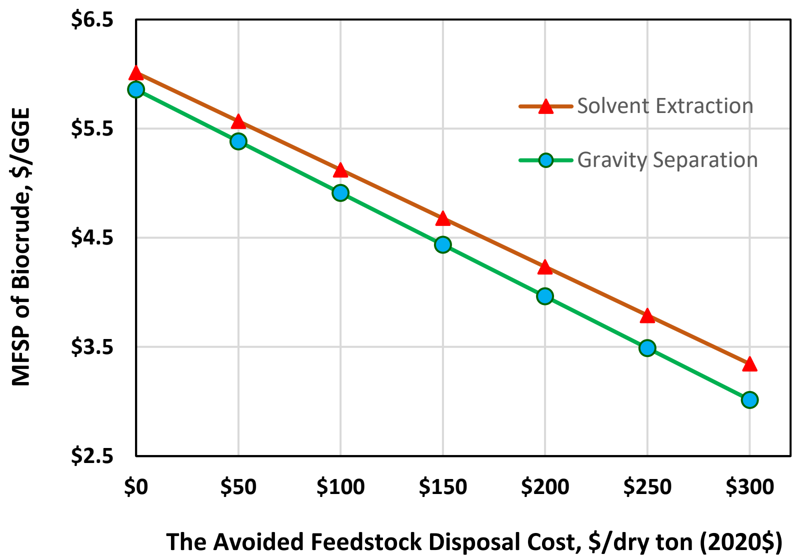


Figure 16. Impact of feedstock credits on MFSP of the biocrude for the cases with gravity separation and solvent extraction.

Figure 17 presents the results from the sensitivity study for the base case using gravity separation. Here, six variables are selected due to the associated high model uncertainties, including (1) volatility of organic components in the four steam flashing drums, (2) biocrude yield which may be impacted by recycling organic components from the steam flashing drums to the reactor, and (3-6) cost estimation of high pressure (HP) equipment, solid handling equipment, site development, and total capital investment. The volatility of organic components impacts the heat balance around the low temperature heat recovery area and therefore the natural gas consumption for feedstock and HTL reactor heating. In addition, it also impacts the flowrate of organic components recycled through the HTL reactor and increases uncertainty in reactor performance. As the associated streams are dominated by water (>80%) and the thermodynamic property package in Aspen Plus is quite reliable for water and light organics, the impact of volatility on MFSP of the biocrude is not significant. Figure 17 also shows a +/- 20 cents difference in MBFP will be expected from a +/- 10% relative variation in biocrude yield, which suggests that even though more experimental study would be required to validate the steam flashing design, the impact of recycling organic products back to the reactor may not significantly impact economic performance of the HTL plant. On the other hand, uncertainties in capital cost estimation may significantly impact the estimated MFSP of the biocrude and economic performance of the technology. The most optimistic case with all variations that may reduce MFSP of the biocrude gives an estimated biocrude MFSP about $1/GGE lower than the base case. The most conservative case will all variations that may increase biocrude MFSP gives an estimated biocrude MFSP about $2/GGE higher than the base case.

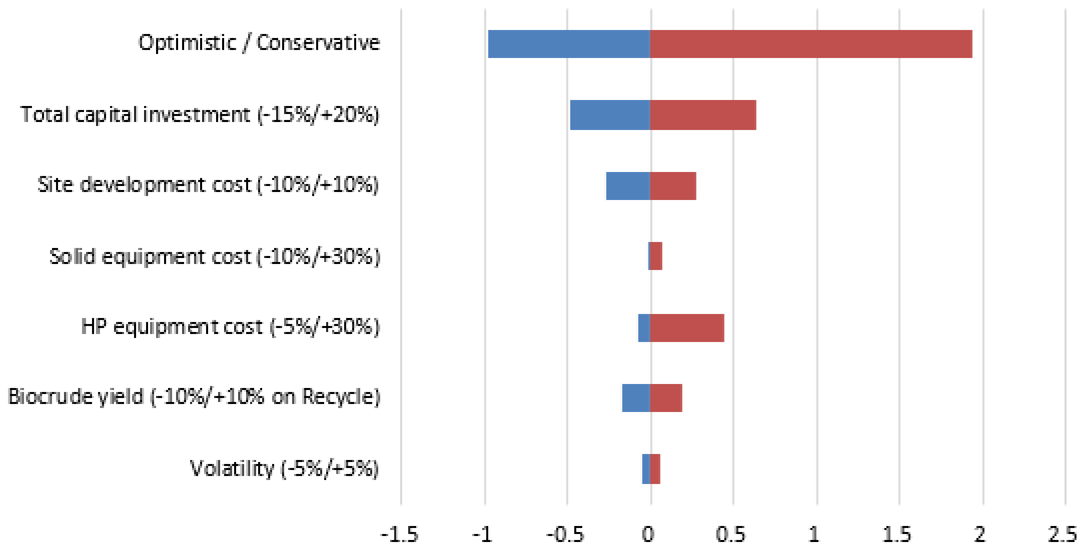


Figure 17. Potential impacts from model accuracy on the estimated biocrude MFSP (base case, gravity separation scenario).

Figure 18 and Table 12 present the uncertainties in carbon efficiency, thermal efficiency, biocrude MFSP and total capital investment (TCI). Here, carbon and thermal efficiency are defined by Equations (8.5.1) and (8.5.2), which are key performance measures of biomass conversion technologies. In the equations, M, wf, and HHV are the mass flowrate, weight fraction, and higher heating value, respectively. A small difference is observed between the base case value and mean value for estimated MFSP of the biocrude and TCI, mainly due to the asymmetrical probability distributions in pricing and equipment cost related parameters, as shown in Figure 18 and Appendix E. In general, the uncertainties in carbon and thermal efficiency estimation are relatively small because of the support from experimental data, but the uncertainty in TCI is large, also illustrated in Figure 18. Overall, the estimated biocrude MFSP ranges from \$3.83/GGE to \$5.06/GGE within 10 to 90 percentiles. The range is much lower than the difference between the optimistic and conservative cases presented in Figure 18, because some low likelihood data points fall outside the confidence interval and therefore excluded.

$$C\% = \frac{M_{Fuel} \times wf_{C,Fuel}}{M_{Feedstock} \times wf_{C,Feedstock} + M_{Natural\ Gas} \times wf_{C,Natural\ Gas}} \times 100\% \quad (8.5.1)$$

$$\eta_{HHV}\% = \frac{M_{Fuel} \times HHV_{C,Fuel}}{M_{Feedstock} \times HHV_{C,Feedstock} + M_{Natural\ Gas} \times HHV_{C,Natural\ Gas}} \times 100\% \quad (8.5.2)$$

Table 12. Statistics of the key performance and economic measures.

	Base Case	Mean	Standard Deviation	10% Percentiles	90% Percentiles
Carbon efficiency (%)	64.2	64.2	3.0	60.4	68.1
Thermal efficiency (%, HHV)	69.9	69.9	3.9	65.0	75.1
MFSP of biocrude (\$/GGE)	4.11	4.43	0.47	3.83	5.06
TCI (MM\$)	93.3	101.4	9.9	89.0	114.9

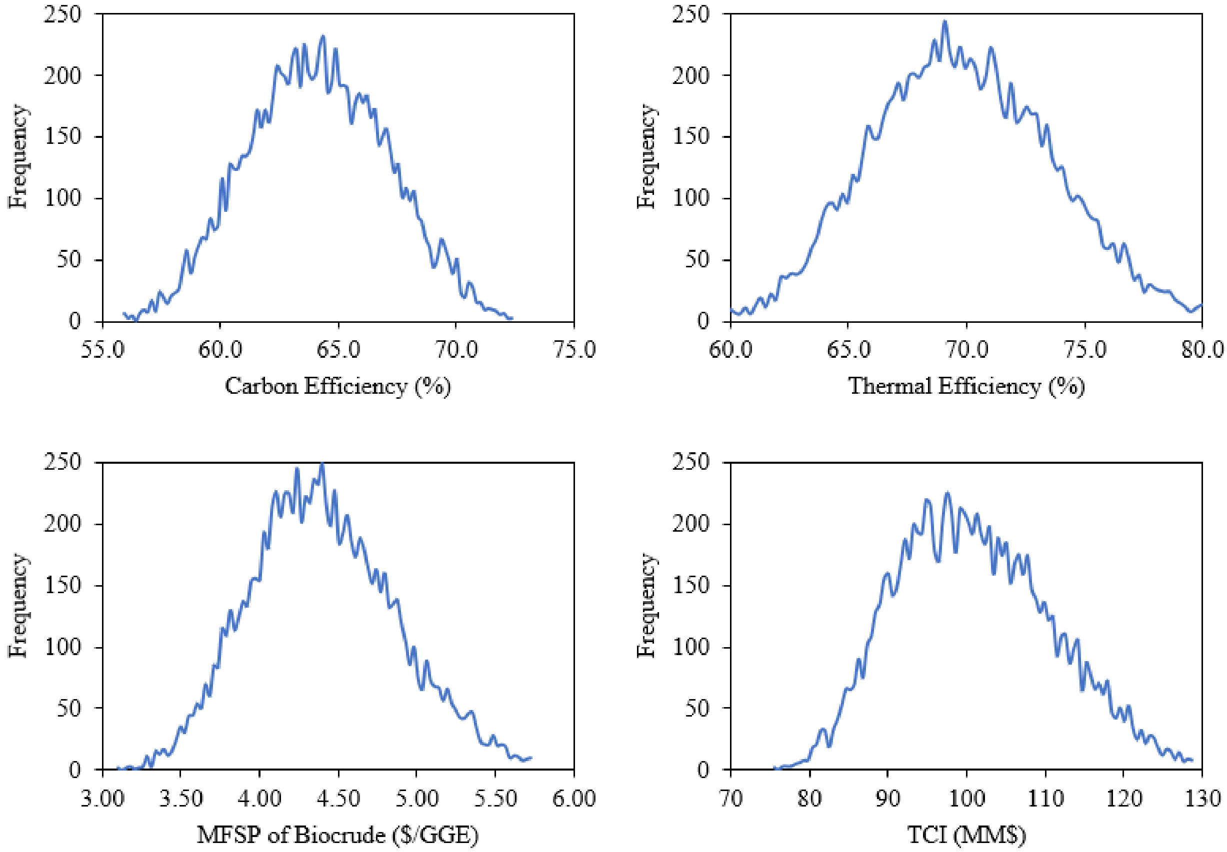


Figure 18. Uncertainties in process and economic measures of the HTL plant (base case, gravity separation).

7.6 Life Cycle Greenhouse Gas Emissions

Figure 19 represents the breakdown of the supply chain GHG emissions of renewable hydrocarbon fuels produced from sludge via the HTL and upgrading processes. Renewable hydrocarbon fuels produced via "gravity separation" are estimated to have GHG emissions of 21.8 g CO_2e/MJ while fuels produced via "solvent separation" have estimated GHG emissions of 30.5 g CO_2e/MJ, corresponding to 76% and 66% GHG emission reduction from the petroleum diesel baseline (91 g CO_{2e}/MJ), respectively.

In both scenarios, the major contributor to the supply chain GHG emissions are the emissions during biocrude production in the HTL plant, accounting for about 61% of the total emissions for the "gravity separation" scenario, and about 72% of the total emissions for the "solvent separation" scenario. The higher GHG emissions in the "solvent separation" scenario can be attributed to two reasons. First, the "solvent separation" scenario consumes 77% more natural gas and 17% more electricity than the "gravity separation" scenario. The increased energy consumption causes an increase of 5.2 g CO_2e/MJ in the total GHG emissions. Second, the "solvent extraction" scenario uses toluene as the organic solvent. The unrecovered toluene is eventually combusted, which releases fossil CO_2. The use of solvent and combustion of the unrecovered solvent contribute 3.7 g CO_2e/MJ to the total emissions.

The potential impacts of lime sludge that is formed during the ammonia stripping process to treat the HTL aqueous waste are also considered. Lime sludge is rich in $CaCO_3$. We assume that this solid waste is transported to a landfill by truck. The carbon in the lime sludge originates from the wastewater sludge and thus we assume that it is biogenic carbon. We assume that 49.2% of the biogenic carbon in the lime sludge upon soil amendment or landfill ends up as biogenic CO_2 emissions (0.216 g CO_2/g $CaCO_3$(Cai, Wang and Han, 2014)), while the remaining will be sequestered and result in a biogenic carbon sequestration credit of -0.224 g CO_2/g $CaCO_3$, which translates to about -1.3 g CO_2e/MJ of fuel in both scenarios.

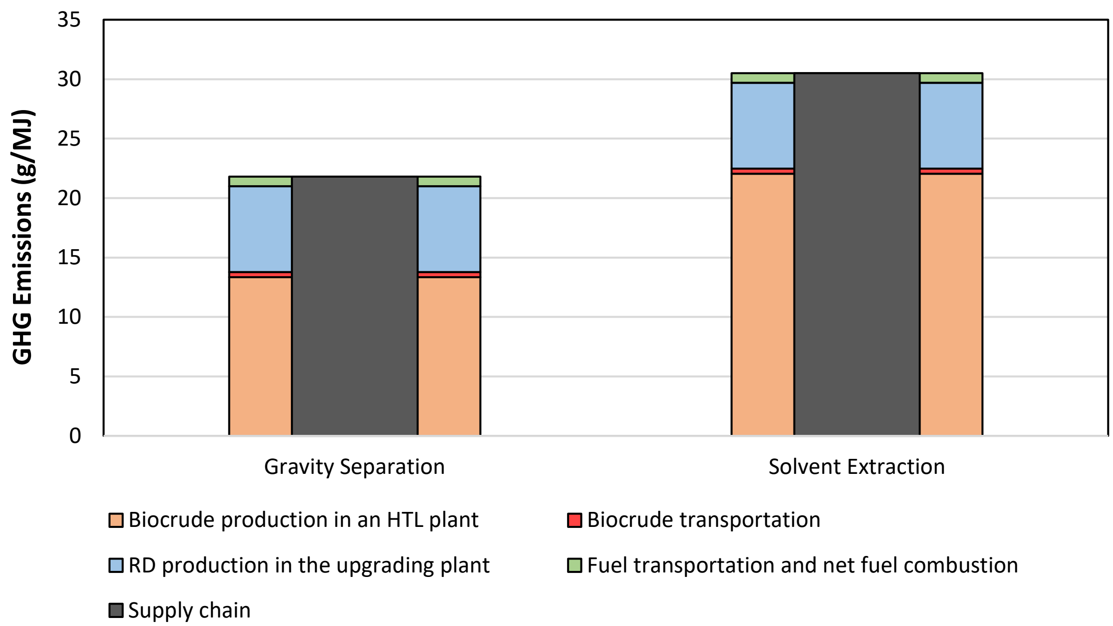


Figure 19. Breakdown of GHG Emissions of Renewable Hydrocarbon Fuels from Sludge HTL.

8.0 Economic Performance for Large Scale Case

8.1 Feedstock Transport Costs

Feedstock travel costs were calculated using a geospatial waste transport model implemented using PostgreSQL, PostGIS, and pgRouting software and a national transportation network developed from the U.S. Census Bureau's 2021 MAF/TIGER state level edge datasets. Feedstock source terms were geolocated prior to transportation network modeling. In total, 100% of wastewater sludge/scum sources and 99.8% of all the IIC food waste locations were successfully geocoded. The least cost path (in hours) was calculated for each waste source to the HTL study location. The maximum travel time for any source within the Detroit CSA is about 2 hours. Total travel costs were then calculated as the total drive time plus total wait time multiplied by the truck chargeout rate for the total number of trips required per year.

Table 13. Feedstock transport assumptions

Feedstock	Loading Wait Time (min)	Unloading Wait Time (min)	Max Truck Capacity (m^3)	Truck Type	Note
Sludge	30	30	30	Tractor-trailer	Marufuzzaman (2015)
Scum	10	15	10	Vacuum truck	2,500 gal
Food Waste	10	15	20.6	RotoPac 27R	New Way (2022)

8.1.1 Truck Traffic

Traffic impacts are a common concern when discussing waste diversion projects, both in terms of potential increases to total ton-miles and funneling traffic through neighborhoods. Performing detailed traffic and congestion modeling is beyond the scope of this project. However, we can generally assess the relative potential impacts of the business-as-usual practice of trucking wastes to landfills compared to diverting waste to the GLWA HTL study location.

For illustration purposes, we evaluate the transport of wastes originating within Wayne County (11.8 million yd^3/y), which is primarily from the City of Detroit and accounts for 34% of total solid waste disposed within the entire Detroit CSA (EGLE, 2023).

In the absence of detailed waste collection routing information, waste-to-landfill routes are represented by the least cost path (time) from the centroid of each Detroit City daily waste collection zone (Figure 20) to each of the 12 MSW landfills occurring in the Detroit CSA that accepted MSW in 2022 (Table 14) (EGLE, 2023). Likewise, waste-to-HTL routes are represented by the shortest paths between the trash collection area centroids and the HTL study location.

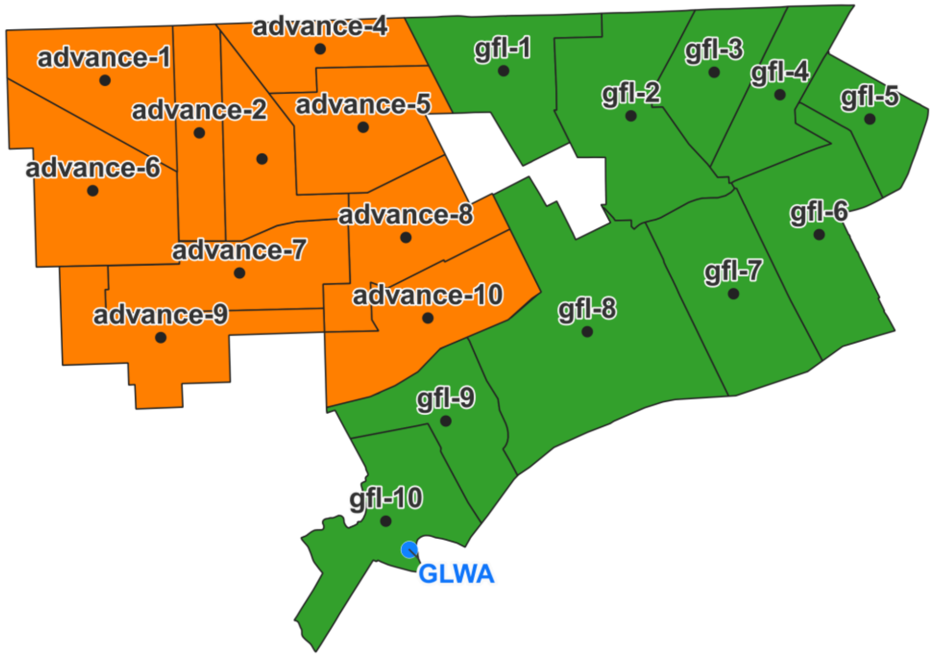


Figure 20. City of Detroit waste collection area centroids

Table 14. Active (2022) MSW landfills in the Detroit CSA

WDSID	NAME	MCW	MCW
		Volume (compact yd^3/y)	Mass (compact dry metric t/d)
TOTAL		***24,494,830***	***12,176***
398972	PINE TREE ACRES, INC.	7610791	3783
412717	WOODLAND MEADOWS	3155441	1569
390701	CARLETON FARMS	3893591	1935
475946	ARBOR HILLS	3319386	1650
412314	EAGLE VALLEY	1301549	647
399054	RIVERVIEW LAND PRESERVE	1036205	515
410118	SAUK TRAIL HILLS	817966	407
470393	VIENNA JUNCTION	753485	375
452546	SMITHS CREEK	797395	396
470517	CITIZENS DISPOSAL, INC.	473366	235
406671	BRENT RUN	723846	360
470494	WESTSIDE	611809	304

Table 15 summarizes the shortest travel routes from each waste collection area centroid to the nearest landfill. Figure 21 illustrates possible shortest routes between all collection areas and all landfills. And Figure 22 presents the shortest routes from collection areas to the proposed GWLA HTL location.

The results indicate, that even under ideal conditions of driving waste to the nearest landfill, the average travel time from city collection areas to landfills is 30 minutes (range of 19–38 minutes). The actual average travel time to landfills is likely much higher as most waste is often transported to the larger landfills in the region, not the closest. For example, the average travel time from collection areas to the largest landfill (PINE TREE ACRES) is 50 minutes (range of 35–58 minutes). In contrast, the average travel time from collection areas to the HTL study location is only 18 minutes (range of 4–24 minutes). Therefore, HTL could decrease average travel times by 40% to 64% compared to disposing of city waste at the closest and largest landfills respectively, thereby substantially reducing total truck traffic (ton-miles) and annual travel costs.

Most of the inner-city waste-related truck traffic is for trash collection rather than diversion to final disposal endpoints. Once the trash trucks leave the waste collection areas, they are travelling primarily on interstate highways (e.g., I-75, I-94, and I-96). Therefore, neighborhood level truck traffic is likely to be similar between landfill disposal and HTL scenarios, while highway traffic is much higher for landfilling than HTL. The exception for HTL is likely to be neighborhood level increases in the southwest portion of the Delray neighborhood, which is bisected by West End Street, a likely corridor that connects GLWA to I-75. However, this impact could be mitigated or avoided entirely by learning from current biosolids trucking patterns or exploring alternative HTL siting and/or alternative solutions for "last-mile" feedstock delivery, such as rail, barge, or pipeline.

Table 15. Minimum travel time from collection areas to nearest landfills

Collection Area	Nearest Landfill Name	Closest (min)	Largest (min)
gfl-1	OAKLAND HEIGHTS	30	46
gfl-2	RIVERVIEW LAND PRESERVE	34	44
gfl-3	RIVERVIEW LAND PRESERVE	36	40
gfl-4	RIVERVIEW LAND PRESERVE	36	41
gfl-5	RIVERVIEW LAND PRESERVE	35	35
gfl-6	RIVERVIEW LAND PRESERVE	38	43
gfl-7	RIVERVIEW LAND PRESERVE	34	46
gfl-8	RIVERVIEW LAND PRESERVE	26	44
gfl-9	RIVERVIEW LAND PRESERVE	24	50
gfl-10	RIVERVIEW LAND PRESERVE	19	52
advance-1	WOODLAND MEADOWS	28	58
advance-2	WOODLAND MEADOWS	27	56
advance-3	WOODLAND MEADOWS	29	54
advance-4	WOODLAND MEADOWS	34	50
advance-5	RIVERVIEW LAND PRESERVE	33	52
advance-6	WOODLAND MEADOWS	22	58
advance-7	WOODLAND MEADOWS	26	54

advance-8	WOODLAND MEADOWS	30	51
advance-9	WOODLAND MEADOWS	24	56
advance-10	RIVERVIEW LAND PRESERVE	25	47

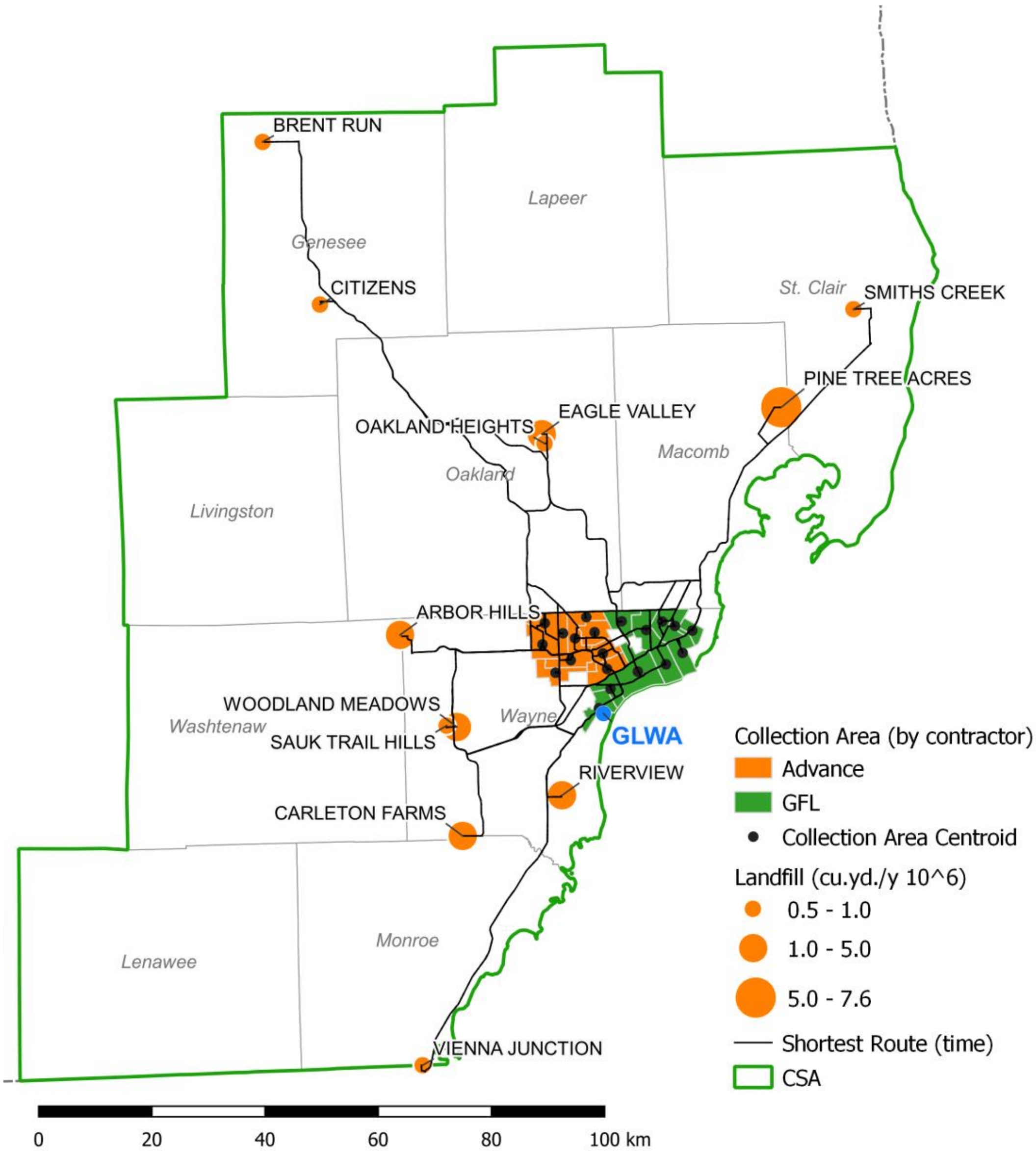


Figure 21. Shortest travel routes (time) from collection areas to landfills.

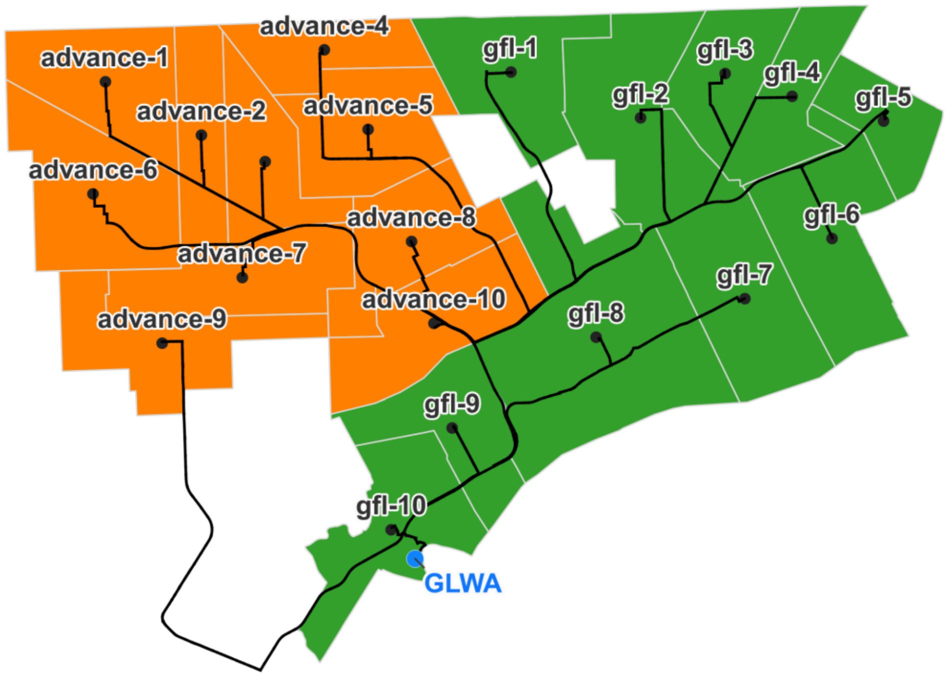


Figure 22. Shortest travel routes (time) from collection areas to GLWA HTL study location

8.1.2 Wait Times

For sludge we assume 30 minutes of loading wait time per trip, which includes staging, loading, verification, truck wash, and documentation, and the same amount of unloading time. For IIC food waste, we assume 10 minutes of loading wait time per load and 15 minutes of unloading. Food waste and scum collection trucks are more efficient during pickup but may experience similar delays in offloading due to queues, weighing, and documentation. The total wait time may exceed the drive time. If transport distance is zero, the wait time is also zero, assuming the material can be fed directly to the HTL unit process.

8.1.3 Truck Chargeout Rate

According to the American Transportation Research Institute (ATRI), the average marginal cost per hour to operate a truck was $90.78 per hour in 2022 (ATRI, 2023). Trucking data indicate fuel and driver wages and benefits, rather than truck type and size, influence trucking costs the most from a TEA perspective, with truck payments representing only 15% of total marginal operating costs per hour and total marginal costs per mile varying by only 12% across all trucking sectors (Appendix D).

8.1.4 Number of Trips Required

Although truck type and capacity do not have a major impact on truck chargeout rates, capacity (and solids concentration) are very important determinants on the total number of required trips per year and therefore total annual delivery costs.

Transporting large quantities of dewatered biosolids typically requires a tractor trailer combination using a covered aluminum end dump trailer with a sealed rear gate to prevent leaking. Scum (FOG) is often transported in drums or in a small vacuum tanker truck. Food wastes are typically collected from commercial establishments using a front-end loading trash truck or specialized industrial aluminum container truck with a side loading arm or lift. There are many configurations available on the market for each truck and container type. Instead of attempting to develop an elaborate optimized waste handling and fleet management schedule, we simply fix the minimum number of deliveries per waste source to ≥1 load per week, as weekly pickups are common in the U.S., and allow the waste producers to select (negotiate) an appropriately sized container up to a maximum size to maintain a weekly pick-up schedule. Partial loads per week are rounded (up or down) to the nearest whole number.

8.2 Analysis Results

As discussed in Section 5.2, the large-scale case takes sludge/scum from Detroit WRRFs and nearby IIC non-residential food waste as feedstock in addition to sludge from the GLWA WRRF. Food waste point sources with extremely small sizes will have a transportation cost much higher than the lost landfill tipping fee revenue, which will not be considered as feedstock to the centralized HTL plant. In addition, for each point source, the wet waste production rate varies. The averaged value is used in resources and HTL plant scale evaluation for this large scale/hot spot case. Four scenarios based on the regional resource analysis detailed in Section 4.0 are considered and summarized in Table 16. In Table 16, the minimum scale of off-site point source is used to filter out food waste point sources with extremely high transportation cost due to small scale and long distance. The delivered feedstock cost is the sum of feedstock transportation cost and landfill tipping fee credits (detailed in Section 8.2). The tipping fee credit for sewage sludge and food waste is set to $187 and $148 per dry ton, respectively (detailed in Sections 4.4 and 7.3). Scenario A only imports off-site sludge from other wastewater treatment facility in the Detroit area, but not food waste. Scenario B imports off-site sludge and food waste from point sources with a scale large enough such that the landfill tipping fee credit can completely offset the transportation cost. About 35.3% of IIC food waste in the region can be delivered to the HTL plant at a “zero” cost after considering landfill tipping fee credit. Scenario C imports off-site sludge and 50% of IIC food waste available in the region, but with a positive delivered price for food waste. Scenario D aims to maximize the local food waste usage for fuel production with a reasonable delivered food waste cost, comparable to the woody biomass (about $75/dry short ton). In Scenario D, the food waste usage increases to 71.7%. Biocrude yields from the Scenario A-D waste blends needed for the cost model were estimated using the predictive yield model developed by Jiang et al. (2023).

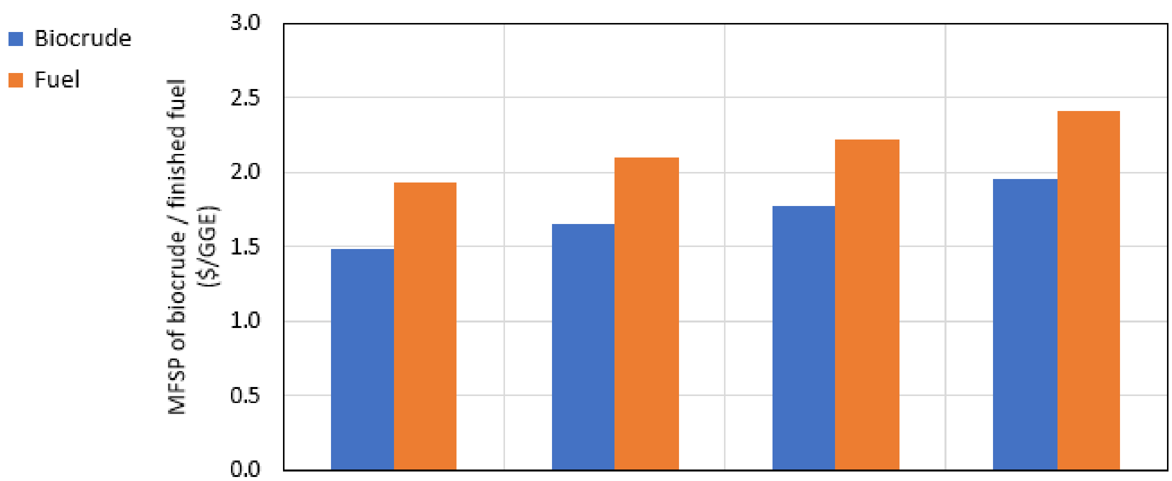
Table 16. Scenarios for large scale/hot spot case.

Scenario	A	B	C	D
Scale (dry short ton/day)	933	1073	1131	1217
Feedstock composition (wt%, dry)				
Sludge	67.3	86.6	82.2	76.3
Scum	0.3	0.3	0.3	0.3
Food waste	0	13.1	17.5	23.4
Minimum scale for off-site point source (wet metric ton/week)	N/A	1.28	1.03	0.83
Food waste usage for biocrude production (%)	0	35.3	50.0	71.7
Off-site feedstock transportation cost ($/dry short ton)				
Sludge	22.3	22.3	22.3	22.3
Food waste	N/A	147.7	190.3	231.3
Delivered feedstock price w/ tipping fee ($/dry short ton)	-179	-156	-141	-120
Equipment cost for feedstock receiving unit (2020 MM$)	0.96	1.23	1.32	1.44

Installed cost for feedstock receiving unit (2020 MM$)	1.84	4.81	6.20	8.82

Figure 23 shows the estimated MFSP of the biocrude and finished biofuel blendstocks for the large-scale waste blend scenarios with gravity separation. If solvent extraction is used, the MFSP results should follow the same trend, and will be couple of cents higher. The feedstock price represents the average delivered price of feedstock at the HTL plant gate, including both on-site and off-site feedstocks, as defined in Equation (8.2.1). Here, TC is the transportation cost, Credits is the avoided feedstock disposal fee, and M is the flowrate. The feedstock price increases as more IIC food waste in the region is delivered to the HTL plant from biocrude production because the average off-site feedstock transportation cost increases as more small-scale and long-distance point sources are added into the feedstock blend. More details about transportation cost can be found in Section 8.1 for the large-scale scenarios. The biocrude yield increases slightly with increasing food waste blending ratio in the feedstock. As the impact of feedstock cost is more significant than the combined impact of plant scale and increased biocrude yield across the four scenarios evaluated in this case, the estimated MFSP increase with the food waste usage. Scenario A, without any food waste usage, has the lowest MFSP of biocrude and finished fuel, \$1.5/GGE and \$1.9/GGE, respectively. Scenario D maximizes the local food waste usage (71.7%) and results in an estimated MFSP for biocrude and finished fuel at \$2.0/GGE and \$2.4/GGE, respectively. If half of the local food waste is used (Scenario C), the estimated MFSP for biocrude and finished fuel are \$1.89/GGE and \$2.2/GGE, respectively. If we only consider the food waste that can be delivered to the HTL plant at “zero” cost after accounting for the landfill tipping fee credits (Scenario B), the estimated MFSP for biocrude and finished fuel are \$1.7/GGE and \$2.1/GGE, respectively.

$$P_{feedstock} = \frac{\sum_i TC_{off-site,i} M_{off-site,i} + \sum_i Credit_i \left(M_{off-site,i} + M_{on-site,i}\right)}{\sum_i M_{off-site,i} + \sum_i M_{on-site,i}} \quad \text{i=sludge, food waste} \qquad (8.2.1)$$



Scenario	A	B	C	D
Scale (dry short ton/day)	933	1073	1131	1217
Composition (sludge/food waste)	100 / 0	87 / 13	82/18	77 / 23
Food waste usage (%)	0	35.3	50.0	71.7
Feedstock price * ($/dry short ton)	-179	-156	-141.5	-120
Biocrude yield (wt%, daf)	43.7	44.0	44.1	44.2

* Including feedstock transportation cost + tipping fee credits

Figure 23. MFSP for biocrude and finished fuel of the large scale / hot spot case (gravity separation).

9.0 Current State of Development/Commercialization

The early continuous-flow process development of HTL started in 1980s (Elliott, Biller, Ross and Andrew J. Schmidt, 2015), including works from Lawrence Berkeley Laboratory and the Albany Biomass Liquefaction Experimental Facility in the U.S. and the Hydrothermal Upgrading plant in the Netherlands, but only on a small scale. In the past decade, tremendous research and development efforts have been made to advance the technology readiness level (TRL) of the wet waste HTL technology in a continuous flow system. DOE's report (DOE Office of Project Management Oversight & Assessments, 2015) provides detailed guidance and information on the technology readiness assessment on a scale from 1 to 9, with TRL 1 representing basic principles and TRL 9 indicating full-scale deployment and proven performance in operational environments. Figure 24 provides estimated TRLs for the major steps of an HTL process as conceptualized in this study. Most of the critical technology elements in the supply chain of wet waste HTL have achieved a TRL level of 6 or 7, while R&D is still needed for the solid separation, aqueous-phase treatment and SAF production steps. Nevertheless, with significant improvement in core technology components and worldwide policy supports for low-carbon fuels, several commercialization efforts have been initiated. Muradel Pty Ltd (Muradel Pty Ltd, 2015) built a demonstration plant in Australia in 2014. Steeper Energy in partnering with Silva Green Fuel built a 30 barrel per day demonstration plant in Tofte, Norway in 2017 and another commercial-scale demonstration plant in 2021(Steeper Energy, 2021). In 2023, Topsoe (Topsoe, 2023), global leader in catalysis and process technology, signed a global licensing agreement with Steeper Energy to introduce complete waste-to-biofuel solution, producing SAF, marine biofuel, and renewable diesel from waste biomass via HTL. AECOM (2022) and Genifuel Corporation started a new project in 2020 for scale production of carbon neutral SAF and biogas from wild algae and biosolid using HTL technology. Circlia Nordic (2021), a Danish company specializing in HTL, started a project in 2021 to establish a HTL demonstration plant that spans the full value chain from sludge to the use of refined fuels. The plant will be set up at Fredericia Spildevand & Energi to convert wastewater sludge to biocrude. The biocrude will then be refined at the Crossbridge Energy A/S refinery in Fredericia. Metro Vancouver, a partnership of 23 local authorities in Canada, is planning to host a 10 wet tonne/day HTL demonstration plant at one of its wastewater treatment plants, as an important investment to meet its sustainability objective of zero net energy, zero odors, and zero residuals. This project is currently in the engineering stage (PNNL, 2016). Arbios Biotech, a joint venture between Licella Holdings Ltd. and Canadian Forest Products Ltd., built a plant called Commercial Stage 1 (CS-1') in 2021 in Somersby, Australia (Licella, 2020), which was designed to process up to 5,000 tonnes of feedstock annually via HTL, and plan to build a pioneering "first-of-a-kind" commercial plant in Prince George, British Columbia (*Arbios Biotech*, 2021).

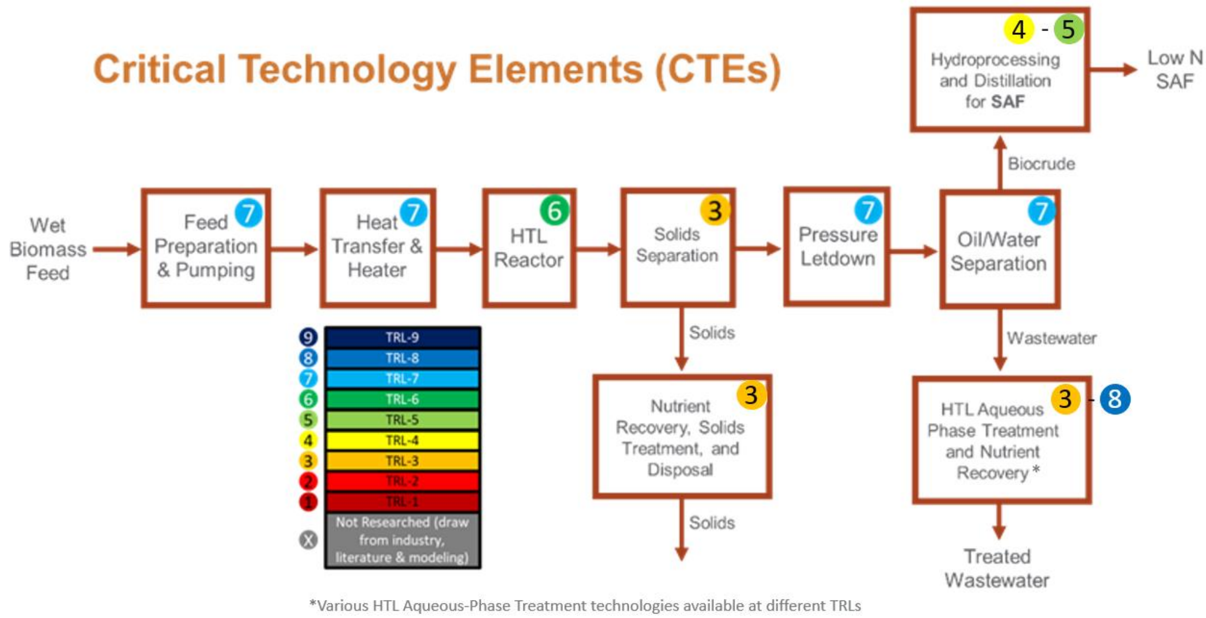


Figure 24. Technology readiness level of critical technology elements in a wet waste HTL plant.

10.0 Conclusions and Next Steps

This business case study is informed by several years of R&D learnings and provides a more robust and detailed process HTL plant design and costing that is consequently better aligned with first-of-a-kind plant economics compared with our previous SOT analyses. This includes 1) additional piping to account for connections to equipment to storage, utilities, and piping racks, 2) equipment redundancies included to decrease operational risk of key equipment, 3) detailed equipment list and costs for the sludge dewatering section (based on WRRF operations), 4) detailed design and costing for HTL solids gravity separation and solvent extraction, and 5) more realistic installment costs for piping, instrument, foundation, and steel structure, which result in a higher overall installed factor and Lang factor for this work.

The TEA results indicate that finished hydrocarbon fuel blendstocks produced from wet waste HTL have the potential to be competitive with fossil fuels. The example site of the GLWA WRRF in Detroit chosen for the analysis is an ideal one as it could allow easy access to an on-site feedstock sludge supply and nearby petroleum refining infrastructure (within 2 miles) for low-cost biocrude upgrading. In addition, GLWA leads, invests, and participates a number of DOE projects aiming to accelerate the deployment of wet waste HTL technology for biofuel production. For the base case (110 dry short ton/day), the estimated MFSP of biocrude is $4.11/GGE when settling and filtration is used for separation of the HTL solids, and $4.37/GEE when solvent extraction is used for HTL solids separation, respectively. The estimated MFSP of finished fuel blendstocks is $4.90/GGE without considering any sustainable fuel credits, when using settling and filtration for solid separation, and the HTL biocrude is sent to the nearby petroleum infrastructure for upgrading. It is $5.16/GGE when solvent extraction is used. The NPV and IRR calculation illustrates the feasibility of near-term HTL demonstration at its current state of technology with the help of sustainable fuel credits (i.e., RFS, LCFS, etc.). A sustainable fuel credit of $1.8/GEE or higher is needed to make a 110 dry ton/day HTL plant economically successful (i.e., a positive NPV). The biocrude MFSP is expected to deviate by +23%/-7% due to the uncertainties in feedstock composition, model accuracy, and pricing assumptions.

The estimated supply chain GHG emissions for renewable hydrocarbon fuel produced from wet waste HTL is 21.8 g CO_{2e}/MJ when using gravity separation, and 30.5 g CO_{2e}/MJ when using solvent extraction, corresponding to 76% and 66% GHG emission reductions from the petroleum diesel baseline (91 g CO_{2e}/MJ), respectively.

The regional resource assessment for the "Detroit CSA" suggests that it is possible to design an up to 1,217 dry short ton/day wet waste HTL plant at the selected site, with additional sludge, scum and non-residential food wastes delivered from other nearby point sources at a reasonable transportation cost. The estimated MFSPs can be as low as $1.49/GGE biocrude and $1.93/GGE finished fuel, respectively, for the large-scale case.

Several years of intensive R&D efforts have helped to advance the TRL of most critical technology elements in the HTL supply chain to 6 or 7. In addition, a number of research, demonstration and commercialization projects have been initiated or announced in the past few years aiming to improve the HTL technology to a complete waste-to-biofuel solution. Future research in several key areas is needed to further advance the technology readiness of the overall process and bolster this business case.

HTL technology de-risking and improvement:

- Investigate the performance of the 2-stage flashing concept for preheating of HTL feedstock in the laboratory if possible.

- Investigate the performance of the settling and filtration method for HTL solids separation at mid-range pressure and temperature (between flash stages).
- Evaluate and improve the efficiency of a scalable solvent extraction unit for HTL solid separation and explore the potential of nutrient recovery from the HTL solid product.
- Investigate settling/filtration of HTL solids at process conditions proposed in this work.
- Explore the feasibility and performance of using commercially available technologies for HTL aqueous-phase treatment (i.e., wet air oxidation).
- Investigate the autothermal HTL concept to de-risk the high temperature heat recovery unit in the current design, which may also produce excess steam for solvent extraction and mitigate challenges for aqueous phase product treatment. In the autothermal HTL, a small amount of oxygen is fed to the first stage of HTL reactor to partially oxidize the organic waste and provide heat required in the HTL reactor.
- Explore the impact of the HTL process on end-of-life PFAS destruction performance and strategy to reduce PFAS pollution, an environmental concern.

Biocrude upgrading de-risking and improvement:

- Demonstrate and optimize biocrude hydrocracking reactor to maximize the production of targeted fuel products (i.e., SAF).
- Evaluate the impact of nitrogen and other heteroatom content in the HTL biocrude on the performance of standalone hydrotreating/hydrocracking reactors and existing reactors in a petroleum refinery (i.e., fuel properties and specifications).

Assessment method improvement:

- Update the process models for the feedstock preheat section, gravity separation at elevated temperature and pressure, and the solvent extraction section with experimental data for more rigorous equipment design and economic assessment.
- Update the impacts of sustainable fuel credits, feedstock variation, availability, and supply chain on the economic and environmental performance of the wet waste HTL technology based on new learnings.

Recommendations for plant siting:

In this business case study, a location specific analysis was conducted for wet waste HTL technology. It is recommended for technology developers, investors, and stakeholders to consider following aspects when selecting a potential location of their own HTL projects.

- Feedstock availability: HTL plants need to be located near a reliable source of feedstocks to minimize feedstock transportation cost and environmental impacts.
- Transportation infrastructure: Access to efficient transportation networks for organic waste is crucial when considering a region or large scale HTL project to gain economic of scale.

- Environmental regulations: HTL plants must comply with federal and local environmental regulations regarding air and water emissions, waste disposal, and land use.

- Community acceptance: Public support and community engagement are important for a successful HTL project and plant siting.

- State-level policies: Regional policy supports (i.e., tax incentives, renewable energy mandates, environmental regulations) have a profound impact on the siting of HTL plants, which can significantly influence HTL project feasibility in additional to federal program (i.e., RFS) and attractiveness.

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Appendix A – Conversion Life Cycle Inventory and Energy and Carbon Efficiencies

Table A.1 Hydrothermal liquefaction plant parameters for greenhouse gas and water analysis.

HTL Plant	2018/2019 SOT with NH_3 Removal	2018/ 2019 SOT without NH_3 Removal	2020 SOT with NH_3 Removal	2020 SOT without NH_3 Removal	2021 SOT with NH_3 Removal	2021 SOT without NH_3 Removal	2022 SOT with NH_3 Removal	2022 SOT without NH_3 Removal
Sludge Properties								
Solids content, %	20	20	20	20	25	25	25	25
Ash content (dry basis), %	15.02	15.02	15.02	15.02	15.02	15.02	15.02	15.02
Biocrude Properties								
Moisture content, %	4	4	4	4	4	4	4	4
Density, lb/gal	8.15	8.15	8.15	8.15	8.15	8.15	8.15	8.15
Lower heating value, Btu/gal	124,943	124,943	124,955	124,955	124,932	124,932	124,932	124,932
Inputs								
Sludge, lb/hr (dry basis)	9,167	9,167	9,167	9,167	9,167	9,167	9,167	9,167
Natural gas, lb/hr	310	135	420	245	229	194	229	194
Electricity, kW (HTL process)	376	342	407	374	326	310	326	310
Electricity, kW (at WRRF for chemical oxygen demand)	0	0	0	0	0	0	0	0
Dewatering polymer, lb/hr	31	31	31	31	42	42	42	42
Quicklime (CaO), lb/hr	994	0	994	0	407	0	407	0
Cooling water makeup, lb/hr	190	190	190	190	197	197	197	197
Outputs								
Biocrude, lb/hr	3,533	3,533	3,533	3,533	3,592	3,592	3,592	3,592
Aqueous phase, lb/hr	29,814	34,694	29,814	34,694	23,612	26,159	23,612	26,159
Wet solids,[(a)] lb/hr	5,681	5,681	5,681	5,681	5,684	5,684	5,684	5,684
Solids from HTL aqueous treatment [(a)], lb/hr	2,091	0	2,091	0	862	0	862	0
Carbon Efficiency								
Biocrude C / Feed C	65.4%	65.4%	65.4%	65.4%	66.9%	66.9%	66.9%	66.9%
Biocrude C / (Feed + NG) C	61.9%	63.8%	60.7%	62.6%	64.3%	64.7%	64.3%	64.7%
Energy Efficiency (LHV)	67.5%	70.9%	65.5%	68.7%	70.3%	71.0%	70.3%	71.0%

(a) 59% moisture content assumed
SOT = state of technology; WRRF = wastewater treatment and water resource recovery facility; NG = natural gas

Appendix B – Cost Factors and Financial Assumptions

Table B.1. Cost factors for direct and indirect project costs.

Direct Costs	
Item	**% of Total Installed Cost (TIC)**
Buildings	4.0%
Site development	20.0%
Additional piping	11.0%
Total Direct Costs (TDC)	34.5%
Indirect Costs	
Item	**% of TDC**
Prorated expenses	10%
Home office & construction fees	20%
Field expenses	10%
Project contingency	10%
Startup and permits	10%
Total Indirect Costs	60%
Working Capital	5% of FCI
Land	HTL: 6 acres @ $15,000/acre Upgrading: 6% of Total Purchased Equipment Cost

Table B.2. Financial assumptions for the economic analysis.

Assumption Description	Assumed Value
Internal rate of return (IRR)	10%
Plant financing debt/equity	60% / 40% of total capital investment (TCI)
Plant life	30 years
Income tax rate	21%
Interest rate for debt financing	8.0% annually
Term for debt financing	10 years
Working capital cost	5.0% of fixed capital investment (excluding land)
Depreciation schedule	7-years MACRS[(a)] schedule
Construction period	3 years (8% 1st yr, 60% 2nd yr, 32% 3rd yr)
Plant salvage value	No value
Start-up time	6 months
Revenue and costs during start-up	Revenue = 50% of normal Variable costs = 75% of normal Fixed costs = 100% of normal
On-stream factor	90% (7,920 operating hours per year)

(a) Modified accelerated cost recovery system

Appendix C – Regional Resource Assessment

Table C.1and Table C.2 list the WRRFs within the Detroit CSA and IIC food waste in Detroit CSA by NAICS code, respectively.

Table C.1 WRRFs within the Detroit CSA

FACILITY	CITY	Influent Flow (MM Gal/d)	Cum. Flow (%)	Wastewater Solids (dry metric t/d)
TOTAL	***N = 81***	***973.1***		***843***
DETROIT STP	DETROIT	660.5	68	569
WYANDOTTE WWTP	WYANDOTTE	81.0	76	74
FLINT WPCF	FLINT	43.3	81	31
YCUA WWTP	YPSILANTI	24.2	83	29
WARREN WWTP	WARREN	30.0	86	21
MONROE METRO WWTP	MONROE	13.4	88	15
HURON VALLEY-SOUTH	ROCKWOOD	14.0	89	13
ANN ARBOR WWTP	ANN ARBOR	15.1	91	13
RAGNONE (DIST.#2) WWTP	MONTROSE	14.0	92	12
PORT HURON WWTP	PORT HURON	11.0	93	9
PONTIAC STP	PONTIAC	8.0	94	7
TRENTON WWTP	TRENTON	6.2	95	5
ADRIAN WWTP	ADRIAN	4.9	95	4
MT CLEMENS WWTP	MOUNT CLEMENS	3.8	96	3
BEDFORD TOWNSHIP STP	ERIE	3.0	96	3
COMMERCE TWP WWTP	COMMERCE	3.0	96	3
MARYSVILLE STP	MARYSVILLE	2.4	96	2
FLUSHING WWTF	FLUSHING	2.2	97	2
GROSSE ISLE TOWNSHIP	GROSSE ILE	2.2	97	2
WALLED LAKE WWTP	NOVI	2.2	97	2
GENESEE COUNTY DIST. 3	LINDEN	2.1	97	2
BERLIN TWP STP	NEWPORT	1.5	97	1
ALGONAC STP	ALGONAC	1.4	98	1
SALINE STP	SALINE	1.4	98	1
WIXOM STP	WIXOM	1.1	98	1
SOUTH LYON WWTP	SOUTH LYON	1.1	98	1
ST CLAIR STP	ST CLAIR	1.1	98	1
HOWELL STP	HOWELL	1.1	98	1
LAPEER STP	LAPEER	1.0	98	1
CHELSEA STP	CHELSEA	0.9	98	1
TECUMSEH STP	TECUMSEH	0.8	98	1

MARINE CITY STP	MARINE CITY	0.8	99	1
MILAN WWTP	MILAN	0.8	99	1
ROMEO VILLAGE STP	ROMEO	0.8	99	1
HOLLY STP	HOLLY	0.7	99	1
BRIGHTON STP	BRIGHTON	0.7	99	1
ROLLIN-WOODSTOCK STP	ADDISON	0.6	99	0.5
MANCHESTER STP	MANCHESTER	0.6	99	0.5
NEW BALTIMORE	NEW BALTIMORE	0.6	99	0.5
EAST CHINA REG CS	EAST CHINA	0.6	99	0.5
HARTLAND TWP. CS	HARTLAND	0.6	99	0.5
BLISSFIELD STP	BLISSFIELD	0.6	99	0.5
MILFORD WWTP	MILFORD	0.6	99	0.4
HUDSON STP	HUDSON	0.5	99	0.4
DUNDEE STP	DUNDEE	0.5	99	0.4
NORTHFIELD STP	WHITMORE LAKE	0.5	99	0.4
FOWLERVILLE WWSL	FOWLERVILLE	0.4	99	0.3
CARLETON LAGOON	CARLETON	0.4	99	0.3
ST. CLAIR RIVER SA WWTP	EAST CHINA	0.4	100	0.3
DEXTER STP	DEXTER	0.4	100	0.3
IMLAY CITY STP	IMLAY CITY	0.4	100	0.3
ARMADA WWTP	ARMADA	0.3	100	0.3
ALMONT WWTP	ALMONT	0.3	100	0.3
CLINTON STP	CLINTON	0.3	100	0.2
MORENCI SEWAGE SYSTEM	MORENCI	0.3	100	0.2
Hamburg Twp WWTP	WHITMORE LAKE	0.2	100	0.2
LUNA PIER STP-CS	LUNA PIER	0.2	100	0.2
YALE STP	YALE	0.2	100	0.1
PETERSBURG WWTP	PETERSBURG	0.2	100	0.1
BRITTON-RIDGEWAY SEWERAGE	BRITTON	0.2	100	0.1
PINCKNEY STP	Pinckney	0.2	100	0.1
ROCKWOOD WWTP-CS	ROCKWOOD	0.2	100	0.1
MEMPHIS STP	MEMPHIS	0.2	100	0.1
IDA-RAISINVILLE WWSL	IDA TWP	0.1	100	0.1
CAPAC STP	CAPAC	0.1	100	0.1
NORTH BRANCH WWTP	NORTH BRANCH	0.1	100	0.1
COLUMBIAVILLE WWTF	COLUMBIAVILLE	0.1	100	0.1

DRYDEN WWTF	DRYDEN	0.1	100	0.1
DEERFIELD (ARGENTINE)	DEERFIELD	0.1	100	0.1
CLIFFORD STP	CLIFFORD	0.1	100	0.1
MAYBEE LAGOON	MAYBEE	0.1	100	0.1
ONSTED STP	ONSTED	0.1	100	0.1
OTISVILLE LAGOON CS	OTISVILLE	0.1	100	0.1
SALEM TOWNSHIP STP	SALEM	0.1	100	0.1
METAMORA WWTF	METAMORA	0.1	100	0.1
LOCH ALPINE STP	ANN ARBOR	0.1	100	0.05
Elba Twp WWTP Lagoon	LAPEER	0.1	100	0.04
FAIRFIELD TWP (JASPER)	JASPER	0.1	100	0.04
CLAYTON LAGOON	CLAYTON	0.04	100	0.03
FAIRFIELD TWP (WESTON)	FAIRFIELD TWP	0.04	100	0.03
EMMETT LAGOON	St. Clair	0.03	100	0.02

Table C.2. IIC food waste in Detroit CSA by NAICS code

NAICS Code	NAICS Code Description	Low	High	Low	High
		wet US t/y		dry metric t/d	
Food Manufacturers and Processors		**19877**	**63747**	**14.8**	**47.5**
112930	Fur-Bearing Animal and Rabbit Production	2	6	0.0	0.0
311211	Flour Milling	0	0	0.0	0.0
311212	Rice Milling	0	0	0.0	0.0
311213	Malt Manufacturing	11	36	0.0	0.0
311221	Wet Corn Milling	180	578	0.1	0.4
311224	Soybean and Other Oilseed Processing	539	1729	0.4	1.3
311225	Fats and Oils Refining and Blending	5	14	0.0	0.0
311230	Breakfast Cereal Manufacturing	12	37	0.0	0.0
311313	Beet Sugar Manufacturing	0	0	0.0	0.0
311314	Cane Sugar Manufacturing	0	0	0.0	0.0
311340	Nonchocolate Confectionery Manufacturing	1299	4167	1.0	3.1
311351	Chocolate and Confectionery Manufacturing	0	0	0.0	0.0
311352	Confectionery Manufacturing from Purchased Chocolate	14	44	0.0	0.0
311411	Frozen Fruit, Juice, and Vegetable Manufacturing	34	109	0.0	0.1
311412	Frozen Specialty Food Manufacturing	354	1135	0.3	0.8
311421	Fruit and Vegetable Canning	605	1939	0.5	1.4
311422	Specialty Canning	187	601	0.1	0.4
311423	Dried and Dehydrated Food Manufacturing	9	27	0.0	0.0

311511	Fluid Milk Manufacturing	64	205	0.0	0.2
311512	Creamery Butter Manufacturing	10	33	0.0	0.0
311513	Cheese Manufacturing	308	989	0.2	0.7
311514	Dry, Condensed, and Evaporated Dairy Product Manufacturing	490	1572	0.4	1.2
311520	Ice Cream and Frozen Dessert Manufacturing	520	1666	0.4	1.2
311611	Animal (except Poultry) Slaughtering	79	252	0.1	0.2
311612	Meat Processed from Carcasses	2074	6651	1.5	5.0
311613	Rendering and Meat Byproduct Processing	9	29	0.0	0.0
311615	Poultry Processing	205	658	0.2	0.5
311710	Seafood Product Preparation and Packaging	74	238	0.1	0.2
311811	Retail Bakeries	961	3079	0.7	2.3
311812	Commercial Bakeries	2023	6489	1.5	4.8
311813	Frozen Cakes, Pies, and Other Pastries Manufacturing	1340	4300	1.0	3.2
311821	Cookie and Cracker Manufacturing	163	522	0.1	0.4
311824	Dry Pasta, Dough, and Flour Mixes	223	715	0.2	0.5
311830	Tortilla Manufacturing	100	320	0.1	0.2
311911	Roasted Nuts and Peanut Butter Manufacturing	0	0	0.0	0.0
311919	Other Snack Food Manufacturing	578	1853	0.4	1.4
311920	Coffee and Tea Manufacturing	112	358	0.1	0.3
311930	Flavoring Syrup and Concentrate Manufacturing	41	130	0.0	0.1
311941	Mayonnaise, Dressing, and Other Prepared Sauce Manf.	389	1247	0.3	0.9
311942	Spice and Extract Manufacturing	514	1648	0.4	1.2
311991	Perishable Prepared Food Manufacturing	864	2773	0.6	2.1
311999	All Other Miscellaneous Food Manufacturing	2196	7043	1.6	5.3
312111	Soft Drink Manufacturing	711	2282	0.5	1.7
312120	Breweries	1376	4412	1.0	3.3
312130	Wineries	156	501	0.1	0.4
312140	Distilleries	1048	3362	0.8	2.5
Food Wholesale and Retail		**12843**	**450699**	**9.6**	**336.1**
424410	General Line Grocery Merchant Wholesalers	1009	22197	0.8	16.6
424420	Packaged Frozen Food Merchant Wholesalers	163	1617	0.1	1.2
424430	Dairy Product (except Dried or Canned) Wholesalers	299	5292	0.2	3.9
424440	Poultry and Poultry Product Merchant Wholesalers	39	2940	0.0	2.2
424450	Confectionery Merchant Wholesalers	270	6027	0.2	4.5
424460	Fish and Seafood Merchant Wholesalers	304	6468	0.2	4.8

424470	Meat and Meat Product Merchant Wholesalers	706	7497	0.5	5.6
424480	Fresh Fruit and Vegetable Merchant Wholesalers	883	9261	0.7	6.9
424490	Other Grocery and Related Products Wholesalers	1513	56451	1.1	42.1
445110	Supermarkets and Other Grocery (except Convenience)	4781	180975	3.6	134.9
445210	Meat Markets	260	16081	0.2	12.0
445220	Fish and Seafood Markets	47	5053	0.0	3.8
445230	Fruit and Vegetable Markets	581	15515	0.4	11.6
445291	Baked Goods Stores	540	65630	0.4	48.9
445292	Confectionery and Nut Stores	92	16497	0.1	12.3
445299	All Other Specialty Food Stores	221	31097	0.2	23.2
452311	Warehouse Clubs and Supercenters	1135	2101	0.8	1.6
Educational Institutions		**10962**	**56047**	**8.2**	**41.8**
n/a	Public Elementary & Secondary	7240	34090	5.4	25.4
n/a	Private Elementary & Secondary	466	2194	0.3	1.6
n/a	Postsecondary	3257	19763	2.4	14.7
Hospitality Industry		**4120**	**21785**	**3.1**	**16.2**
713210	Casinos (except Casino Hotels)	516	2727	0.4	2.0
721110	Hotels and Motels	3037	16057	2.3	12.0
721120	Casino Hotels	568	3001	0.4	2.2
Correctional Facilities		**2168**	**3917**	**1.6**	**2.9**
922140	Correctional Institutions	2168	3917	1.6	2.9
Healthcare Facilities		**1839**	**9869**	**1.4**	**7.4**
622110	General Medical and Surgical Hospitals	1746	9373	1.3	7.0
622210	Psychiatric and Substance Abuse Hospitals	0	0	0.0	0.0
622310	Specialty Hospitals	92	496	0.1	0.4
Restaurants and Food Services		**85963**	**222786**	**64.1**	**166.1**
722320	Caterers	2328	7830	1.7	5.8
722330	Mobile Food Services	222	444	0.2	0.3
722511	Full-Service Restaurants	42750	111446	31.9	83.1
722513	Limited-Service Restaurants	40172	102018	30.0	76.1
722514	Cafeterias, Grill Buffets, and Buffets	451	909	0.3	0.7
722515	Snack and Nonalcoholic Beverage Bars	39	140	0.0	0.1

Appendix D Transport & Disposal Costs

Table D.1 Average marginal costs per hour (CPH) for 2022 (ATRI, 2023)

Component	CPH
Vehicle Related	
Fuel Costs	$25.84
Truck/Trailer Lease or Purchase	$13.37
Repair & Maintenance	$7.89
Truck Insurance Premiums	$3.57
Permits & Licenses	$0.60
Tires	$1.81
Tolls	$1.14
Driver Related	
Driver Wages	$29.20
Driver Benefits	$7.37
TOTAL	$90.78

Table D.2 Average total marginal costs per mile (CPM) by sector in 2022 (ATRI, 2023)

Truck sector	CPM
LTL	$2.34
Specialized	$2.44
TL	$2.15

Table D.3. Average tipping fee for major landfills in Wayne County, Michigan

Landfill Name	Tipping Fee ($/wet short ton)
ARBOR HILLS LANDFILL, INC	33.50
CARLETON FARMS LANDFILL	20.00
RIVERVIEW LAND PRESERVE	42.00
SAUK TRAIL HILLS LANDFILL	43.20
WOODLAND MEADOWS RDF-VAN BUREN	60.00
AVERAGE	**39.74**

Appendix E Key Sources of Uncertainties for the Sewage Sludge HTL Process

Table E.1. Uncertainty Sources for the Sewage Sludge HTL Process

Model Input	Unit	Base Value	Sensitivity		Uncertainty			
			Lower	Upper	Type	alpha	beta	gamma
General Economic Assumptions								
Natural Gas Price	$/ kscf	3.51			L	4.05	0.87	2.44
Electricity Price	¢/kwh	6.76			T	6.76	5.83	7.66
Utility Consumption	Actual/Predicted	1			T	1	0.9	1.1
Feedstock Composition								
Lipid	AFDW	25.2			N	25.2	4.100	
Protein	AFDW	44.3			N	44.3	4.900	
Carbohydrate	AFDW	30.5						
Ash in total solids	AFDW	15.02			N	15.02	2.600	
Sludge + Ash in Feed	wt%	25			T	25.0	22.5	27.5
Steam Flashing Separation Efficiency - Relative Volatility Difference								
Water		0%	-2.5%	2.5%	T	0.0%	-2.5%	2.5%
Light biocrude		0%	-10.0%	0.0%	T	0.0%	-10.0%	0.0%
Heavy biocrude		0%	-5.0%	5.0%	T	0.0%	-5.0%	5.0%
Light aqueous		0%	-5.0%	5.0%	T	0.0%	-5.0%	5.0%
Heavy aqueous		0%	-5.0%	5.0%	T	0.0%	-5.0%	5.0%
Impact of Organic Fraction Recycling on Biocrude Yield								
Relative change	%/26.4% oil recycled	0%	-10.0%	10.0%	T	0.0%	-10.0%	10.0%
Wastewater Treatment Model								
Quicklime Consumption	Actual/Predicted	1			N	1	0.1	
COD	Actual/Predicted	1			N	1	0.1	
Equipment Design and Capital Costs								
Total cost of HP equipment		0.0%	-5.0%	30.0%	T	0.0%	-5.0%	30.0%
Total cost of solid separation		0.0%	-10.0%	30.0%	T	0.0%	-10.0%	30.0%
Side development cost factor		20.0%	10.0%	30.0%	T	20.0%	10.0%	30.0%
Fixed Capital Investment - AACE Class IV		0.0%	-15.0%	20.0%	T	0.0%	-15.0%	30.0%

N = Normal distribution (α = mean; β = σ); L=Lognormal distribution (α = mean; β = σ; γ = location);
T = Triangular distribution (α = likeliest; β = min; γ = max)

Appendix F Equipment Cost Summary

Table F.1. Equipment List and Cost for Sludge Dewatering (A100)

Equipment Number	Number Required	Number Spares	Equipment Name	Original Equip Cost (per unit)	Base Year	COST BASIS: installed (i) or bare (b)	Total Original Equip Cost (Req'd & Spare) in Base Year	Scaled Cost in Base Year	Installation Factor	Installed Cost in Base Year	Installed Cost in 2020$	Scaled Uninstalled Cost in 2020$	CE Index base year	CE Index 2020
A 100	**Feed Prep - Sludge Feedstock Dewatering**													
ST-101	1	0	Dewater Structure	$435,100	2022	i	$435,100	435,100	1.00	435,100	317,900	$317,900	816.0	596.2
ST-102	1	0	Cake Hopper Structure	$407,400	2022	b	$407,400	407,400	1.00	407,400	297,662	$297,662	816.0	596.2
V-101	1	0	WW Feed Tank	$224,000	2022	b	$224,000	224,000	2.77	620,480	453,346	$163,663	816.0	596.2
P-101A/B/C	3	0	WW Feed Pump	$10,100	2022	b	$30,300	30,300	12.31	373,114	272,611	$22,138	816.0	596.2
P-101D	0	1	WW Feed Pump Spare	$10,100	2022	b	$10,100	10,100	12.32	124,392	90,885	$7,379	816.0	596.2
V-102	1	0	WW Return Tank	$224,000	2022	b	$224,000	224,000	2.67	598,080	436,980	$163,663	816.0	596.2
P-102A/B/C	3	0	WW Return Feed Pump	$15,600	2022	b	$46,800	46,800	8.52	398,689	291,297	$34,194	816.0	596.2
P-102D	0	1	WW Return Feed Pump Spare	$15,600	2022	b	$15,600	15,600	8.52	132,896	97,099	$11,398	816.0	596.2
C-101A/B/C	3	0	Bowl Centrifuge	$576,400	2022	b	$1,729,200	1,729,200	1.27	2,196,084	1,604,541	$1,263,418	816.0	596.2
G101A/B	2	0	Sludge Inline Grinder	$50,000	2022	b	$100,000	100,000	2.07	207,000	151,242	$73,064	816.0	596.2
M-101A/B	2	0	Sludge/Polymer Blending Units	$200,000	2022	b	$400,000	400,000	1.21	482,600	352,606	$292,255	816.0	596.2
Polymer Preparation Part														
V-103A/B	2	0	Sludge Polymer Aging Tank	$84,200	2022	b	$168,400	168,400	3.05	514,400	375,840	$123,039	816.0	596.2
V-104A/B	2	0	Sludge Neat Polymer Tanks	$84,200	2022	b	$168,400	168,400	2.27	382,800	279,688	$123,039	816.0	596.2
P-103A/B/C	3	1	Sludge Dilu Polymer Pumps	$60,000	2022	b	$240,000	240,000	4.57	1,096,400	801,071	$175,353	816.0	596.2
P-103A/B	2	1	Sludge Neat Recirc Pumps	$20,000	2022	b	$60,000	60,000	6.57	393,900	287,798	$43,838	816.0	596.2
P-104A	1	0	Polymer Feed Pump	$4,500	2022	b	$4,500	4,500	9.96	44,820	32,747	$3,288	816.0	596.2
P-104B	0	1	Polymer Feed Pump Spare	$4,500	2022	b	$4,500	4,500	9.96	44,820	32,747	$3,288	816.0	596.2
Dewatered Cake														
V-105A/B/C	3	0	Cake Hopper	$74,300	2022	b	$222,900	222,900	1.70	378,930	276,860	$162,859	816.0	596.2
P-105A/B/C	3	0	Sludge HTL Feed Pump	$55,200	2022	b	$165,600	165,600	3.93	650,808	475,505	$120,994	816.0	596.2
P-105D	0	1	Sludge HTL Feed Pump Spare	$55,200	2022	b	$55,200	55,200	3.61	199,272	145,596	$40,331	816.0	596.2
Odor Control														
F-101	1	1	Fan	$19,200	2022	b	$38,400	38,400	3.44	132,096	96,514	$28,056	816.0	596.2
V-106A/B	2	0	Scrubber Chemicals Tanks	$36,600	2022	b	$73,200	73,200	9.89	723,948	528,943	$53,483	816.0	596.2
P-106A/b	2	0	Scrubber Chemical Pumps	$12,000	2022	b	$24,000	24,000	9.54	228,960	167,287	$17,535	816.0	596.2
T-101	1	0	Wet Scrubber	$150,000	2022	b	$150,000	150,000	1.25	187,500	136,994	$109,596	816.0	596.2
								$4,997,600		$10,954,489	$8,003,758	$3,651,433		

Table F.2. Equipment List and Cost for HTL Reaction and Biocrude Separation for Gravity Separation Case (A200A)

Equipment Number	Number Required	Number Spares	Equipment Name	Original Equip Cost (per unit)	Base Year	COST BASIS: installed (i) or bare (b)	Total Original Equip Cost (Req'd & Spare) in Base Year	Scaled Cost in Base Year	Installation Factor	Installed Cost in Base Year	Installed Cost in 2020$	Scaled Uninstalled Cost in 2020$	CE Index base year	CE Index 2020
A200	HTL Reaction and Biocrude Separation													
Low Pressure Part														
V-201	1	0	1st heating Drum	$120,200	2022	b	$120,200	120,200	4.18	502,436	367,098	$87,823	816.0	596.2
V-202	1	0	2nd Flash Drum	$142,900	2022	b	$142,900	142,900	3.67	524,443	383,178	$104,408	816.0	596.2
V-203	1	0	Emergency KO Vessel	$46,400	2022	b	$46,400	46,400	8.83	409,712	299,351	$33,902	816.0	596.2
V-204	1	0	2nd heating Drum	$180,300	2022	b	$180,300	180,300	2.69	485,007	354,364	$131,734	816.0	596.2
V-206	1	0	1st Flash Drum	$218,600	2022	b	$218,600	218,600	2.39	522,454	381,724	$159,717	816.0	596.2
V-207	1	0	Oil-Water Separator	$130,500	2022	b	$130,500	130,500	3.84	501,120	366,137	$95,348	816.0	596.2
P-201A/B/C	3	1	1st HTL Pump	$81,000	2022	b	$324,000	324,000	3.26	1,056,240	771,728	$236,726	816.0	596.2
P-202A/B/C	3	1	2nd HTL Pump	$81,000	2022	b	$324,000	324,000	3.26	1,056,240	771,728	$236,726	816.0	596.2
P-203	0	1	Light Biocrude Pump Spare	$7,700	2022	b	$7,700	7,700	9.97	76,769	56,090	$5,626	816.0	596.2
P-203	1	0	Light Biocrude Pump	$7,700	2022	b	$7,700	7,700	12.54	96,558	70,549	$5,626	816.0	596.2
HX-201	1	0	Water Cooler	$15,300	2022	b	$15,300	15,300	11.63	177,939	130,009	$11,179	816.0	596.2
P-204	1	1	WW Pump	$12,000	2022	b	$24,000	24,000	10.80	259,200	189,381	$17,535	816.0	596.2
High Pressure Part														
P-204	3	1	HTL feed Pump	$1,620,000	2022	b	$6,480,000	6,480,000	1.70	11,016,000	8,048,700	$4,734,529	816.0	596.2
C-201	3	1	HP HTL Pump VFDs	$142,200	2022	b	$568,800	568,800	1.00	568,800	415,586	$415,586	816.0	596.2
HX-202	1	0	HTL Effluent_HO HX	$852,209	2022	b	$852,209	852,209	1.40	1,193,093	871,718	$622,656	816.0	596.2
HX-203	1	0	Feed_HO HX	$910,423	2022	b	$910,423	910,423	1.37	1,247,280	911,309	$665,189	816.0	596.2
	2	0	HX spare	$910,423	2022	b	$1,820,846	1,820,846	1.37	2,494,559	1,822,618	$1,330,378	816.0	596.2
R-201	1	0	HTL reactor	$804,800	2022	b	$804,800	804,800	3.83	3,082,384	2,252,105	$588,017	816.0	596.2
U-201	2	0	HP Pressure Letdown Station	$674,200	2022	b	$1,348,400	1,348,400	2.36	3,177,000	2,321,235	$985,191	816.0	596.2
Heating Oil System														
F-201	1	1	Dowtherm Heater	$657,013	2022	b	$1,314,026	1,314,026	1.47	1,931,618	1,411,312	$960,076	816.0	596.2
P-205	1	1	HO Circulation Pump	$20,200	2022	b	$40,400	40,400	8.59	347,036	253,557	$29,518	816.0	596.2
V-208	1	1	HO Expansion Tank Tower	$15,000	2022	b	$30,000	30,000	1.53	45,900	33,536	$21,919	816.0	596.2
Solid Separation														
V-205	1	0	Settling Tank	$46,700	2022	b	$46,700	46,700	7.00	326,900	238,845	$34,121	816.0	596.2
V-209	2	0	HTL solid Loading Tank	$161,000	2019	b	$322,000	322,000	1.97	633,600	621,815	$316,011	607.5	596.2
U-202	1	0	Truck Loading Scale	$120,600	2019	b	$120,600	120,600	1.75	211,100	207,173	$118,357	607.5	596.2
U-203	2	1	Filter	$437,400	2022	b	$1,312,200	1,312,200	1.69	2,217,618	1,620,274	$958,742	816.0	596.2
Biocrude Cooling/Separation														
V-210	1	0	Main Oil/water separator	$470,900	2019	b	$470,900	470,900	1.69	793,700	778,937	$462,141	607.5	596.2
H-210	1	1	Biocrude pump	$44,900	2019	b	$89,800	89,800	2.67	240,200	235,732	$88,130	607.5	596.2
HX-210	1	0	Biocrude cooler	$27,120	2019	b	$27,120	27,120	5.30	143,700	141,027	$26,616	607.5	596.2
								$18,100,824		$35,338,605	$26,326,817	$13,483,526		

Table F.3. Equipment List and Cost for HTL Reaction and Biocrude Separation for Solvent Extraction Case (A200B)

Equipment Number	Number Required	Number Spares	Equipment Name	Original Equip Cost (per unit)	Base Year	COST BASIS: installed (i) or bare (b)	Original Equip Cost (Req'd & Spare) in Base Year	Scaled Cost in Base Year	Installation Factor	Installed Cost in Base Year	Installed Cost in 2020$	Scaled Uninstalled Cost in 2020$	CE Index base year	CE Index 2020
A200	**HTL Reaction and Biocrude Separation**													
Low Pressure Part														
V-201	1	0	**1st heating Drum**	$120,200	2022	b	$120,200	120,200	4.18	502,436	367,098	$87,823	816.0	596.2
V-202	1	0	**2nd Flash Drum**	$142,900	2022	b	$142,900	142,900	3.67	524,443	383,178	$104,408	816.0	596.2
V-203	1	0	**Emergency KO Vessel**	$46,400	2022	b	$46,400	46,400	8.83	409,712	299,351	$33,902	816.0	596.2
V-204	1	0	**2nd heating Drum**	$180,300	2022	b	$180,300	180,300	2.69	485,007	354,364	$131,734	816.0	596.2
V-206	1	0	**1st Flash Drum**	$218,600	2022	b	$218,600	218,600	2.39	522,454	381,724	$159,717	816.0	596.2
V-207	1	0	**Oil-Water Separator**	$130,500	2022	b	$130,500	130,500	3.84	501,120	366,137	$95,348	816.0	596.2
P-201A/B/C	3	1	**1st HTL Pump**	$81,000	2022	b	$324,000	324,000	3.26	1,056,240	771,728	$236,726	816.0	596.2
P-202A/B/C	3	1	**2nd HTL Pump**	$81,000	2022	b	$324,000	324,000	3.26	1,056,240	771,728	$236,726	816.0	596.2
P-203	0	1	**Light Biocrude Pump Spare**	$7,700	2022	b	$7,700	7,700	9.97	76,769	56,090	$5,626	816.0	596.2
P-203	1	0	**Light Biocrude Pump**	$7,700	2022	b	$7,700	7,700	12.54	96,558	70,549	$5,626	816.0	596.2
HX-201	1	0	**Water Cooler**	$15,300	2022	b	$15,300	15,300	11.63	177,939	130,009	$11,179	816.0	596.2
P-204	1	1	**WW Pump**	$12,000	2022	b	$24,000	24,000	10.80	259,200	189,381	$17,535	816.0	596.2
High Pressure Part														
P-204	3	1	**HTL feed Pump**	$1,620,000	2022	b	$6,480,000	6,480,000	1.70	11,016,000	8,048,700	$4,734,529	816.0	596.2
C-201	3	1	**HP HTL Pump VFDs**	$142,200	2022	b	$568,800	568,800	1.00	568,800	415,586	$415,586	816.0	596.2
HX-202	1	0	**HTL Effluent_HO HX**	$852,209	2022	b	$852,209	852,209	1.40	1,193,093	871,718	$622,656	816.0	596.2
HX-203	1	0	**Feed_HO HX**	$910,423	2022	b	$910,423	910,423	1.37	1,247,280	911,309	$665,189	816.0	596.2
	2	0	**HX spare**	$910,423	2022	b	$1,820,846	1,820,846	1.37	2,494,559	1,822,618	$1,330,378	816.0	596.2
R-201	1	0	**HTL reactor**	$804,800	2022	b	$804,800	804,800	3.83	3,082,384	2,252,105	$588,017	816.0	596.2
U-201	2	0	**HP Pressure Letdown Station**	$674,200	2022	b	$1,348,400	1,348,400	2.36	3,177,000	2,321,235	$985,191	816.0	596.2
Heating Oil System														
F-201	1	1	**Dowtherm Heater**	$657,013	2022	b	$1,314,026	1,314,026	1.47	1,931,618	1,411,312	$960,076	816.0	596.2
P-205	1	1	**HO Circulation Pump**	$20,200	2022	b	$40,400	40,400	8.59	347,036	253,557	$29,518	816.0	596.2
V-208	1	1	**HO Expansion Tank Tower**	$15,000	2022	b	$30,000	30,000	1.53	45,900	33,536	$21,919	816.0	596.2
Solvent Extraction and Solid Separation														
HX-201	1	0	**Aqueous/Tower Feed Economizer**	$65,900	2022	b	$65,900	65,900	1.99	131,100	95,787	$48,149	816.0	596.2
HX-201	0	1	**Aqueous/Tower Feed Economizer**	$65,900	2022	b	$65,900	65,900	1.95	128,600	93,960	$48,149	816.0	596.2
HX-202	1	0	**Water Cooler**	$34,800	2022	b	$34,800	34,800	2.93	101,800	74,379	$25,426	816.0	596.2
HX-202	0	1	**Water Cooler**	$34,800	2022	b	$34,800	34,800	2.89	100,500	73,429	$25,426	816.0	596.2
V-201	1	0	**1st Setteler**	$335,600	2022	b	$335,600	335,600	2.15	720,500	526,424	$245,202	816.0	596.2
V-202	1	0	**2nd Setteler**	$335,600	2022	b	$335,600	335,600	2.15	720,500	526,424	$245,202	816.0	596.2
T-201	1	0	**Solvent Recovery Tower**	$84,100	2022	b	$84,100	84,100	7.21	606,500	443,131	$61,447	816.0	596.2
HX-203	1	0	**Reboiler**	$65,400	2022	b	$65,400	65,400	5.56	363,600	265,660	$47,784	816.0	596.2
HX-203	0	1	**Reboiler**	$65,400	2022	b	$65,400	65,400	4.33	283,200	206,916	$47,784	816.0	596.2
HX-204	1	0	**conderser**	$157,700	2022	b	$157,700	157,700	10.45	1,648,572	1,204,508	$115,221	816.0	596.2
V-203	1	0	**Oil-Water Separator**	$39,000	2022	b	$39,000	39,000	2.15	83,729	61,176	$28,495	816.0	596.2
P-201	1	1	**Biocrude Pump**	$44,900	2022	b	$89,800	89,800	2.67	240,200	175,499	$65,611	816.0	596.2
P-202	2	2	**Aqueous Pump**	$44,900	2022	b	$179,600	179,600	3.23	580,000	423,770	$131,222	816.0	596.2
HC-201	1	1	**Hydrocyclone**	$20,600	2022	b	$41,200	41,200	19.26	793,600	579,834	$30,102	816.0	596.2
V-209	2	0	**HTL solid Loading Tank**	$161,000	2019	b	$322,000	322,000	1.97	633,600	621,815	$316,011	607.5	596.2
U-202	1	0	**Truck Loading Scale**	$120,600	2019	b	$120,600	120,600	1.75	211,100	207,173	$118,357	607.5	596.2
U-203	2	1	**Filter**	$437,400	2022	b	$1,312,200	1,312,200	1.69	2,217,618	1,620,274	$958,742	816.0	596.2
Biocrude Cooling/Separation														
V-210	1	0	**Main Oil/water separator**	$470,900	2019	b	$470,900	470,900	1.69	793,700	778,937	$462,141	607.5	596.2
P-210	1	1	**Biocrude pump**	$44,900	2019	b	$89,800	89,800	2.67	240,200	235,732	$88,130	607.5	596.2
HX-210	1	0	**Biocrude cooler**	$27,120	2019	b	$27,120	27,120	5.30	143,700	141,027	$26,616	607.5	596.2
								$19,695,624		$41,841,006	$31,077,714	$14,648,747		

Table F.4. Equipment List and Cost for HTL Aqueous Treatment (A300)

Equipment Number	Number Required	Number Spares	Equipment Name	Original Equip Cost (per unit)	Base Year	COST BASIS: installed (i) or bare (b)	Total Original Equip Cost (Req'd & Spare) in Base Year	Scaled Cost in Base Year	Installation Factor	Installed Cost in Base Year	Installed Cost in 2020$	Scaled Uninstalled Cost in 2020$	CE Index base year	CE Index 2020
A300	HTL Aqueous Treatment													
F-301	1	0	Lime feeders	$5,000	2022	b	$5,000	5,000	2.59	12,950	9,462	$3,653	816.0	596.2
HX-301	1	0	flue gas- air Economizer	$150,000	2022	b	$150,000	150,000	2.17	325,500	237,822	$109,596	816.0	596.2
C-301	1	0	air blower	$139,000	2022	b	$139,000	139,000	1.97	273,830	301,380	$152,985	541.7	596.2
CL-215	1	0	Lime softening	$126,600	2022	b	$126,600	126,600	2.02	255,732	266,040	$131,703	573.1	596.2
P-301	1	1	WW Pump	$18,600	2022	b	$37,200	37,200	5.20	193,440	190,784	$36,689	604.5	596.2
T-220	1	0	Ammonia stripping	$412,800	2022	b	$412,800	412,800	2.07	854,496	888,938	$429,439	573.1	596.2
TX-230	1	0	THROX for NH3 destruction	$601,100	2022	b	$601,100	601,100	2.05	1,232,255	1,281,924	$625,329	573.1	596.2
P-302	1	1	Lime sludge Pump	$74,800	2022	b	$149,600	149,600	2.82	421,872	416,080	$147,546	604.5	596.2
								$1,696,100		$3,781,011	$3,800,469	$1,710,712		

Table F.5. Equipment List and Cost for Balance of Plant (A400)

Equipment Number	Number Required	Number Spares	Equipment Name	Original Equip Cost (per unit)	Base Year	COST BASIS: installed (i) or bare (b)	Total Original Equip Cost (Req'd & Spare) in Base Year	Scaled Cost in Base Year	Installation Factor	Installed Cost in Base Year	Installed Cost in 2020$	Scaled Uninstalled Cost in 2020$	CE Index base year	CE Index 2020
A400	Balance of Plant													
	1	0	Cooling Tower System - packaged	$8,100	2022	b	$8,100	8,100	25.42	205,900	214,199	$8,426	573.1	596.2
	1	1	Cooling Water Pump	$12,200	2022	b	$24,400	24,400	10.11	246,600	256,540	$25,383	573.1	596.2
	1	0	Plant Air Compressor	$440,300	2022	b	$440,300	440,300	1.72	758,700	554,334	$321,700	816.0	596.2
	1	0	Firewater Pump	$12,400	2022	b	$12,400	12,400	9.98	123,700	90,380	$9,060	816.0	596.2
	1	0	Instrument Air Dryer	$8,349	2016	b	$8,349	8,349	2.47	20,622	22,697	$9,189	541.7	596.2
	1	0	Plant Air Receiver	$21,005	2016	b	$21,005	21,005	5.44	114,267	125,764	$23,118	541.7	596.2
	1	0	Firewater Storage Tank	$12,900	2022	b	$12,900	12,900	5.98	77,100	56,332	$9,425	816.0	596.2
	1	0	Biocrude Storage - 3 day (S316)	$65,900	2022	b	$65,900	65,900	2.92	192,300	200,051	$68,556	573.1	596.2
	1	0	Flare	$17,200	2022	b	$17,200	17,200	3.39	58,366	42,644	$12,567	816.0	596.2
	1	0	Flare Seal Drum	$24,600	2022	b	$24,600	24,600	12.67	311,800	324,368	$25,592	573.1	596.2
	1	0	Flare KO drum	$24,600	2022	b	$24,600	24,600	12.67	311,682	227,726	$17,974	816.0	596.2
	1	0	Boiler-PACKAGED	$325,980	2022	b	$325,980	325,980	2.86	932,700	681,465	$238,173	816.0	596.2
	1	0	BFW Tank	$44,100	2022	b	$44,100	44,100	7.08	312,100	324,680	$45,878	573.1	596.2
	A400 Total							$1,029,834	6.11	$3,665,837	$3,121,180	$815,041		

Appendix G Discount Cash Flow Rate of Return Worksheet

Table G.1. Discount Cash Flow for Gravity Separation Case

Year		-2	-1	0	1	2	3	4	5	6
Fixed Capital Investment		2,841,920	21,314,403	11,367,682						
Land		85,321								
Working Capital				4,440,501						
Loan Payment					7,941,187	7,941,187	7,941,187	7,941,187	7,941,187	7,941,187
Loan Interest Payment		341,030	2,898,759	4,262,881	4,262,881	3,968,616	3,650,811	3,307,580	2,936,892	2,536,548
Loan Principal		4,262,881	36,234,486	53,286,008	49,607,702	45,635,132	41,344,756	36,711,150	31,706,855	26,302,217
Fuel Sales					11,804,877	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836
By-Product Credit					-	-	-	-	-	-
Total Annual Sales					11,804,877	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836
Annual Manufacturing Cost										
Avoided Sludge Disposal Cost					(5,030,039)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)
CHG catalyst					-	-	-	-	-	-
Baghouse Bags					529,003					529,003
HP letdown station Maintainance					472,177	472,177	472,177	472,177	472,177	472,177
Other Variable Costs					4,464,382	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151
Fixed Operating Costs					4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735
Total Product Cost					5,331,258	3,763,344	3,763,344	3,763,344	3,763,344	4,292,347
Annual Depreciation										
General Plant Writedown					0.14290	0.24490	0.17490	0.12490	0.08930	0.08920
Depreciation Charge					12,690,951	21,749,572	15,532,871	11,092,371	7,930,734	7,921,853
Net Revenue					(10,480,213)	(13,741,697)	(7,207,191)	(2,423,460)	1,108,865	989,087
Losses Forward						(10,480,213)	(24,221,910)	(31,429,101)	(33,852,561)	(32,743,696)
Taxable Income					(10,480,213)	(24,221,910)	(31,429,101)	(33,852,561)	(32,743,696)	(31,754,609)
Income Tax					-	-	-	-	-	-
Annual Cash Income					(1,467,568)	4,035,305	4,035,305	4,035,305	4,035,305	3,506,302
Discount Factor		1.2100	1.1000	1.0000	0.9091	0.8264	0.7513	0.6830	0.6209	0.5645
Annual Present Value	50,400,782				(1,334,153)	3,334,963	3,031,784	2,756,167	2,505,607	1,979,216
Total Capital Investment + Interest		3,954,609	26,634,478	20,071,063						
Net Present Worth				0						

Year	7	8	9	10	11	12	13	14	15	16
Fixed Capital Investment										
Land										
Working Capital										
Loan Payment	7,941,187	7,941,187	7,941,187	7,941,187	-	-	-	-	-	-
Loan Interest Payment	2,104,177	1,637,217	1,132,899	588,236	0	0	0	0	0	0
Loan Principal	20,465,208	14,161,238	7,352,951	0	0	0	0	0	0	0
Fuel Sales	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836
By-Product Credit	-	-	-	-	-	-	-	-	-	-
Total Annual Sales	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836
Annual Manufacturing Cost										
Avoided Sludge Disposal Cost	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)
CHG catalyst	-	-	-	-	-	-	-	-	-	-
Baghouse Bags					529,003					529,003
HP letdown station Maintainance	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177
Other Variable Costs	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151
Fixed Operating Costs	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735
Total Product Cost	3,763,344	3,763,344	3,763,344	3,763,344	4,292,347	3,763,344	3,763,344	3,763,344	3,763,344	4,292,347
Annual Depreciation										
General Plant Writedown	0.08930	0.04460								
Depreciation Charge	7,930,734	3,960,927								
Net Revenue	1,941,580	6,378,348	10,843,592	11,388,255	11,447,488	11,976,491	11,976,491	11,976,491	11,976,491	11,447,488
Losses Forward	(31,754,609)	(29,813,030)	(23,434,681)	(12,591,089)	(1,202,834)	-	-	-	-	-
Taxable Income	(29,813,030)	(23,434,681)	(12,591,089)	(1,202,834)	10,244,654	11,976,491	11,976,491	11,976,491	11,976,491	11,447,488
Income Tax	-	-	-	-	2,151,377	2,515,063	2,515,063	2,515,063	2,515,063	2,403,973
Annual Cash Income	4,035,305	4,035,305	4,035,305	4,035,305	9,296,111	9,461,428	9,461,428	9,461,428	9,461,428	9,043,516
Discount Factor	0.5132	0.4665	0.4241	0.3855	0.3505	0.3186	0.2897	0.2633	0.2394	0.2176
Annual Present Value	2,070,749	1,882,499	1,711,363	1,555,785	3,258,230	3,014,703	2,740,639	2,491,490	2,264,991	1,968,133
Total Capital Investment + Interest										
Net Present Worth										

Year	17	18	19	20	21	22	23	24	25	26
Fixed Capital Investment										
Land										
Working Capital					-	-	-	-	-	-
Loan Payment	-	-	-	-	-	-	-	-	-	-
Loan Interest Payment	0	0	0	0	0	0	0	0	0	0
Loan Principal	0	0	0	0	0	0	0	0	0	0
Fuel Sales	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836
By-Product Credit	-	-	-	-	-	-	-	-	-	-
Total Annual Sales	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836	15,739,836
Annual Manufacturing Cost										
Avoided Sludge Disposal Cost	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)
CHG catalyst	-	-	-	-	-	-	-	-	-	-
Baghouse Bags										
HP letdown station Maintainance	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177
Other Variable Costs	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151	5,102,151
Fixed Operating Costs	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735	4,895,735
Total Product Cost	3,763,344	3,763,344	3,763,344	3,763,344	3,763,344	3,763,344	3,763,344	3,763,344	3,763,344	3,763,344
Annual Depreciation										
General Plant Writedown										
Depreciation Charge										
Net Revenue	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491
Losses Forward	-	-	-	-	-	-	-	-	-	-
Taxable Income	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491	11,976,491
Income Tax	2,515,063	2,515,063	2,515,063	2,515,063	2,515,063	2,515,063	2,515,063	2,515,063	2,515,063	2,515,063
Annual Cash Income	9,461,428	9,461,428	9,461,428	9,461,428	9,461,428	9,461,428	9,461,428	9,461,428	9,461,428	9,461,428
Discount Factor	0.1978	0.1799	0.1635	0.1486	0.1351	0.1228	0.1117	0.1015	0.0923	0.0839
Annual Present Value	1,871,893	1,701,721	1,547,019	1,406,381	1,278,528	1,162,298	1,056,635	960,577	873,252	793,865
Total Capital Investment + Interest										
Net Present Worth										

Year	27	28	29	30
Fixed Capital Investment				
Land				(85,321)
Working Capital	-	-	-	(4,440,501)
Loan Payment	-	-	-	-
Loan Interest Payment	0	0	0	0
Loan Principal	0	0	0	0
Fuel Sales	15,739,836	15,739,836	15,739,836	15,739,836
By-Product Credit	-	-	-	-
Total Annual Sales	15,739,836	15,739,836	15,739,836	15,739,836
Annual Manufacturing Cost				
Avoided Sludge Disposal Cost	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)
CHG catalyst	-	-	-	-
Baghouse Bags				
HP letdown station Maintainance	472,177	472,177	472,177	472,177
Other Variable Costs	5,102,151	5,102,151	5,102,151	5,102,151
Fixed Operating Costs	4,895,735	4,895,735	4,895,735	4,895,735
Total Product Cost	3,763,344	3,763,344	3,763,344	3,763,344
Annual Depreciation				
General Plant Writedown				
Depreciation Charge				
Net Revenue	11,976,491	11,976,491	11,976,491	11,976,491
Losses Forward	-	-	-	-
Taxable Income	11,976,491	11,976,491	11,976,491	11,976,491
Income Tax	2,515,063	2,515,063	2,515,063	2,515,063
Annual Cash Income	9,461,428	9,461,428	9,461,428	9,461,428
Discount Factor	0.0763	0.0693	0.0630	0.0573
Annual Present Value	721,696	656,087	596,443	542,221
Total Capital Investment + Interest				(259,368)
Net Present Worth				

Table G.2. Discount Cash Flow for Solvent Extraction Case

Year		-2	-1	0	1	2	3	4	5	6
Fixed Capital Investment		3,143,545	23,576,590	12,574,181						
Land		85,321								
Working Capital				4,911,790						
Loan Payment					8,784,018	8,784,018	8,784,018	8,784,018	8,784,018	8,784,018
Loan Interest Payment		377,225	3,206,416	4,715,318	4,715,318	4,389,822	4,038,286	3,658,628	3,248,597	2,805,763
Loan Principal		4,715,318	40,080,203	58,941,475	54,872,775	50,478,579	45,732,848	40,607,458	35,072,036	29,093,781
Fuel Sales					13,492,590	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120
By-Product Credit					-	-	-	-	-	-
Total Annual Sales					13,492,590	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120
Annual Manufacturing Cost										
Avoided Sludge Disposal Cost					(5,030,039)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)
CHG catalyst					-	-	-	-	-	-
Baghouse Bags					529,003					529,003
HP letdown station Maintainance					472,177	472,177	472,177	472,177	472,177	472,177
Other Variable Costs					5,037,181	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779
Fixed Operating Costs					5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960
Total Product Cost					6,247,283	4,761,197	4,761,197	4,761,197	4,761,197	5,290,201
Annual Depreciation										
General Plant Writedown					0	0	0	0	0	0
Depreciation Charge					14,037,895	24,057,945	17,181,440	12,269,650	8,772,456	8,762,633
Net Revenue					(11,507,906)	(15,218,845)	(7,990,804)	(2,699,356)	1,207,869	1,131,524
Losses Forward						(11,507,906)	(26,726,751)	(34,717,555)	(37,416,911)	(36,209,042)
Taxable Income					(11,507,906)	(26,726,751)	(34,717,555)	(37,416,911)	(36,209,042)	(35,077,518)
Income Tax					-	-	-	-	-	-
Annual Cash Income					(1,538,711)	4,444,904	4,444,904	4,444,904	4,444,904	3,915,901
Discount Factor		1	1	1	1	1	1	1	1	1
Annual Present Value	55,739,589				(1,398,828)	3,673,475	3,339,522	3,035,929	2,759,936	2,210,424
Total Capital Investment + Interest		4,363,371	29,461,307	22,201,289						
Net Present Worth				0						

Year	7	8	9	10	11	12	13	14	15	16
Fixed Capital Investment										
Land										
Working Capital										
Loan Payment	8,784,018	8,784,018	8,784,018	8,784,018	-	-	-	-	-	-
Loan Interest Payment	2,327,503	1,810,981	1,253,138	650,668	0	0	0	0	0	0
Loan Principal	22,637,266	15,664,229	8,133,350	0	0	0	0	0	0	0
Fuel Sales	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120
By-Product Credit	-	-	-	-	-	-	-	-	-	-
Total Annual Sales	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120
Annual Manufacturing Cost										
Avoided Sludge Disposal Cost	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)
CHG catalyst	-	-	-	-	-	-	-	-	-	-
Baghouse Bags					529,003					529,003
HP letdown station Maintainance	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177
Other Variable Costs	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779
Fixed Operating Costs	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960
Total Product Cost	4,761,197	4,761,197	4,761,197	4,761,197	5,290,201	4,761,197	4,761,197	4,761,197	4,761,197	5,290,201
Annual Depreciation										
General Plant Writedown	0	0								
Depreciation Charge	8,772,456	4,381,316								
Net Revenue	2,128,963	7,036,625	11,975,784	12,578,254	12,699,919	13,228,922	13,228,922	13,228,922	13,228,922	12,699,919
Losses Forward	(35,077,518)	(32,948,555)	(25,911,930)	(13,936,146)	(1,357,892)	-	-	-	-	-
Taxable Income	(32,948,555)	(25,911,930)	(13,936,146)	(1,357,892)	11,342,027	13,228,922	13,228,922	13,228,922	13,228,922	12,699,919
Income Tax	-	-	-	-	2,381,826	2,778,074	2,778,074	2,778,074	2,778,074	2,666,983
Annual Cash Income	4,444,904	4,444,904	4,444,904	4,444,904	10,318,093	10,450,849	10,450,849	10,450,849	10,450,849	10,032,936
Discount Factor	1	0	0	0	0	0	0	0	0	0
Annual Present Value	2,280,939	2,073,581	1,885,073	1,713,703	3,616,429	3,329,962	3,027,239	2,752,035	2,501,850	2,183,459
Total Capital Investment + Interest										
Net Present Worth										

Year	17	18	19	20	21	22	23	24	25	26
Fixed Capital Investment										
Land										
Working Capital					-	-	-	-	-	-
Loan Payment	-	-	-	-	-	-	-	-	-	-
Loan Interest Payment	0	0	0	0	0	0	0	0	0	0
Loan Principal	0	0	0	0	0	0	0	0	0	0
Fuel Sales	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120
By-Product Credit	-	-	-	-	-	-	-	-	-	-
Total Annual Sales	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120	17,990,120
Annual Manufacturing Cost										
Avoided Sludge Disposal Cost	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)
CHG catalyst	-	-	-	-	-	-	-	-	-	-
Baghouse Bags										
HP letdown station Maintainance	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177	472,177
Other Variable Costs	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779	5,756,779
Fixed Operating Costs	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960	5,238,960
Total Product Cost	4,761,197	4,761,197	4,761,197	4,761,197	4,761,197	4,761,197	4,761,197	4,761,197	4,761,197	4,761,197
Annual Depreciation										
General Plant Writedown										
Depreciation Charge										
Net Revenue	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922
Losses Forward	-	-	-	-	-	-	-	-	-	-
Taxable Income	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922	13,228,922
Income Tax	2,778,074	2,778,074	2,778,074	2,778,074	2,778,074	2,778,074	2,778,074	2,778,074	2,778,074	2,778,074
Annual Cash Income	10,450,849	10,450,849	10,450,849	10,450,849	10,450,849	10,450,849	10,450,849	10,450,849	10,450,849	10,450,849
Discount Factor	0	0	0	0	0	0	0	0	0	0
Annual Present Value	2,067,645	1,879,677	1,708,797	1,553,452	1,412,229	1,283,845	1,167,132	1,061,029	964,572	876,883
Total Capital Investment + Interest										
Net Present Worth										

Year	27	28	29	30
Fixed Capital Investment				
Land				(85,321)
Working Capital	-	-	-	(4,911,790)
Loan Payment	-	-	-	-
Loan Interest Payment	0	0	0	0
Loan Principal	0	0	0	0
Fuel Sales	17,990,120	17,990,120	17,990,120	17,990,120
By-Product Credit	-	-	-	-
Total Annual Sales	17,990,120	17,990,120	17,990,120	17,990,120
Annual Manufacturing Cost				
Avoided Sludge Disposal Cost	(6,706,719)	(6,706,719)	(6,706,719)	(6,706,719)
CHG catalyst	-	-	-	-
Baghouse Bags				
HP letdown station Maintainance	472,177	472,177	472,177	472,177
Other Variable Costs	5,756,779	5,756,779	5,756,779	5,756,779
Fixed Operating Costs	5,238,960	5,238,960	5,238,960	5,238,960
Total Product Cost	4,761,197	4,761,197	4,761,197	4,761,197
Annual Depreciation				
General Plant Writedown				
Depreciation Charge				
Net Revenue	13,228,922	13,228,922	13,228,922	13,228,922
Losses Forward	-	-	-	-
Taxable Income	13,228,922	13,228,922	13,228,922	13,228,922
Income Tax	2,778,074	2,778,074	2,778,074	2,778,074
Annual Cash Income	10,450,849	10,450,849	10,450,849	10,450,849
Discount Factor	0	0	0	0
Annual Present Value	797,167	724,697	658,815	598,923
Total Capital Investment + Interest				(286,377)
Net Present Worth				

Appendix H Process Flow Diagrams and Stream Information

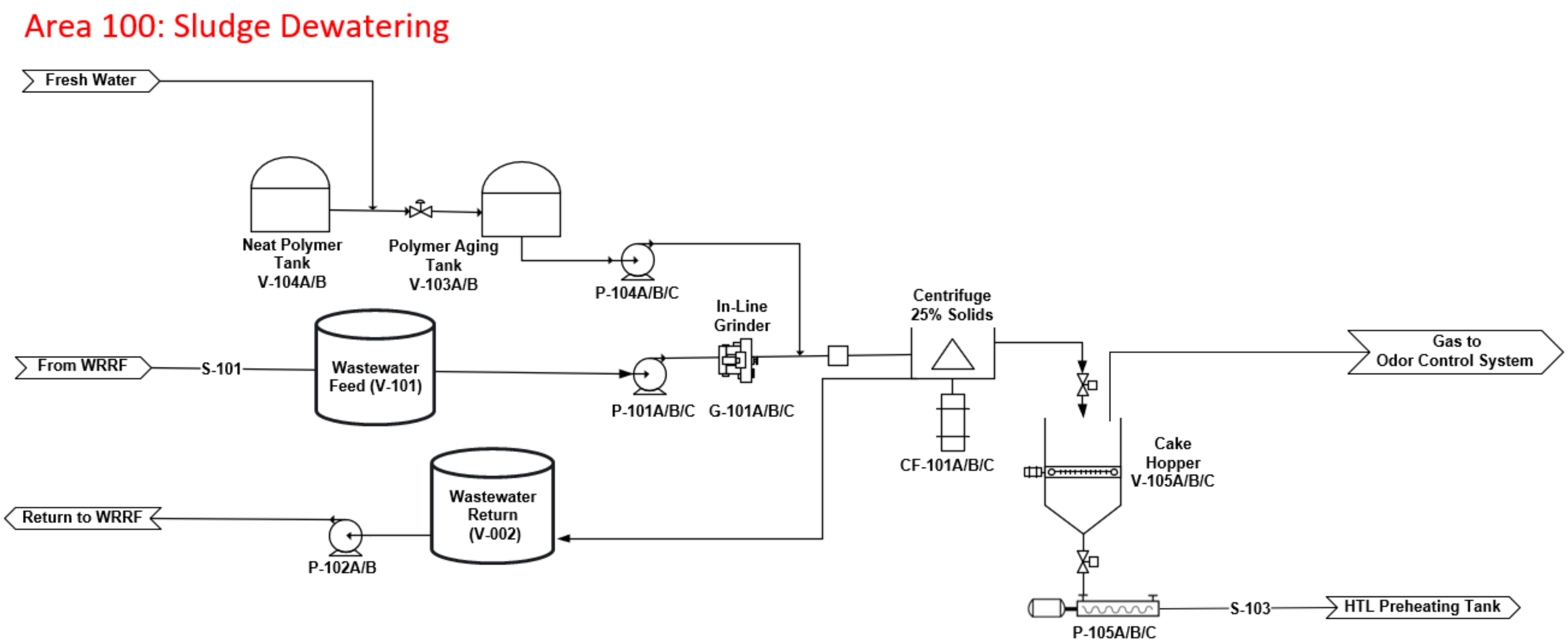

Figure H.1. Sludge Feedstock Dewatering

Area 200: HTL Reaction and Biocrude Separation

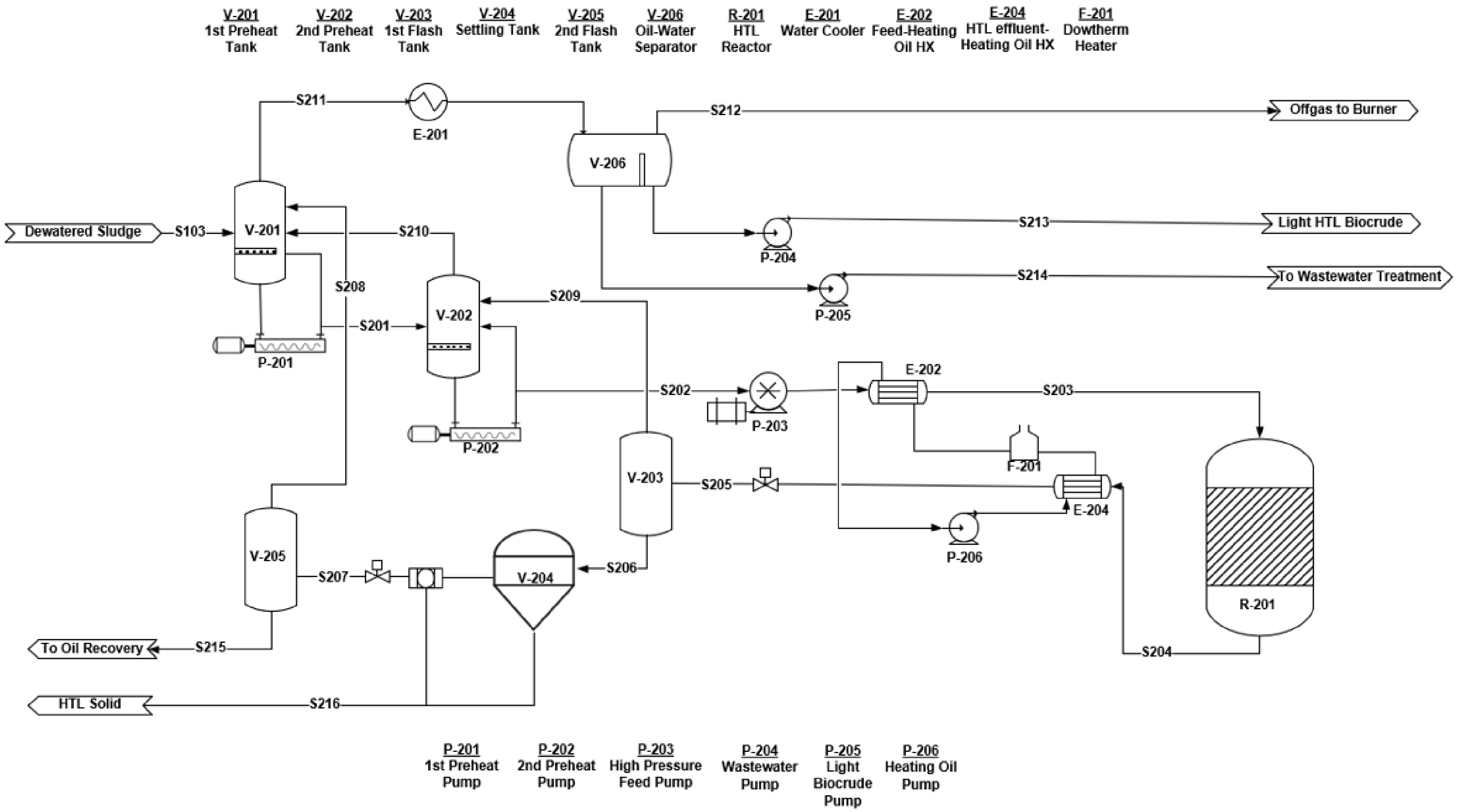

Figure H.2. HTL Flash and Reaction PFD (same for gravity separation and solvent extraction)

Stream Name	S-103	S-201	S-202	S-203A	S-203B	S-204	S-205	S-209	S-207	S-208	S-215	S-210	S-211	S-212	S-213	S-214
Total Stream																
Temperatu F	60	193	328	338	656	656	394	393	309	308	308	328	193	-1	11	11
Pressure psia	15	25	220	3069	2979	2900	280	280	80	80	80	220	25	24	23	23
Mass Flows lb/hr	36667	41052	47319	47319	47319	47319	47319	9995	37324	3936	33388	3728	3279	1483	1206	590
H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2	0	12	83	83	83	1525	1525	1494	30	30	0	1423	1441	1398	33	10
H2O	27500	31062	35870	35870	35870	36049	36049	5570	30478	3329	27149	763	529	1	6	523
NH3	0	133	321	321	321	454	454	243	212	108	103	54	30	1	0	29
CH4	0	0	0	0	0	38	38	38	0	0	0	37	37	37	0	0
C2H6	0	0	1	1	1	13	13	12	0	0	0	12	12	11	0	0
C3H8	0	0	0	0	0	4	4	4	0	0	0	4	4	3	0	0
N-C4H10	0	0	2	2	2	37	37	36	1	1	0	34	34	24	10	0
N-PENTAN	0	0	1	1	1	13	13	13	0	0	0	12	12	5	7	0
SLUDGE	9167	9167	9167	9167	9167	0	0	0	0	0	0	0	0	0	0	0
ASH	0	0	0	0	0	1378	1378	0	1378	0	1378	0	0	0	0	0
SOLID	0	0	0	0	0	950	950	0	950	0	950	0	0	0	0	0
METHANOL	0	4	10	10	10	17	17	7	10	4	6	1	1	0	0	1
ETHANOL	0	32	76	76	76	113	113	57	57	26	31	13	7	0	2	5
ACETONE	0	65	157	157	157	235	235	138	97	58	39	45	39	1	17	21
ACEACID	0	57	143	143	143	529	529	90	439	55	384	4	2	0	0	1
PROACID	0	25	66	66	66	233	233	43	190	24	167	2	1	0	0	0
2-PYRRLD	0	1	3	3	3	218	218	3	216	1	215	0	0	0	0	0
2-PIPERD	0	2	9	9	9	134	134	7	127	2	125	0	0	0	0	0
7-LACTAM	0	0	0	0	0	15	15	0	15	0	15	0	0	0	0	0
C5H9NS	0	1	3	3	3	238	238	3	235	1	235	0	0	0	0	0
TOLUENE	0	1	5	5	5	47	47	45	2	2	0	41	41	1	40	0
RYRO3ETM	0	35	50	50	50	142	142	125	17	14	2	110	89	0	89	0
PHENO4M	0	23	65	65	65	153	153	47	106	19	87	4	1	0	0	0
AMIPHENO	0	0	0	0	0	6	6	0	6	0	6	0	0	0	0	0
INDOLE	0	58	134	134	134	211	211	103	107	37	70	27	7	0	7	0
2-PYTENE	0	9	26	26	26	719	719	702	18	17	0	685	694	0	694	0
C15OLEF	0	1	2	2	2	122	122	121	1	1	0	119	120	0	120	0
MC12AMID	0	4	18	18	18	101	101	14	87	4	83	1	0	0	0	0
C16AMIDE	0	22	103	103	103	486	486	86	400	18	383	4	0	0	0	0
C18AMIDE	0	43	176	176	176	575	575	147	428	30	399	13	0	0	0	0
C16:0FA	0	190	597	597	597	1139	1139	493	646	105	541	86	1	0	1	0
C18:1FA	0	75	139	139	139	217	217	123	94	36	58	59	20	0	20	0
C13H18	0	0	1	1	1	33	33	32	0	0	0	32	32	0	32	0
HEVOIL1	0	0	0	0	0	387	387	0	387	0	387	0	0	0	0	0
HEVOIL2	0	31	88	88	88	168	168	75	93	14	79	18	1	0	1	0
C16H1-01	0	0	0	0	0	495	495	0	495	0	495	0	0	0	0	0
TRIOL-01	0	0	0	0	0	125	125	125	0	0	0	125	125	0	125	0

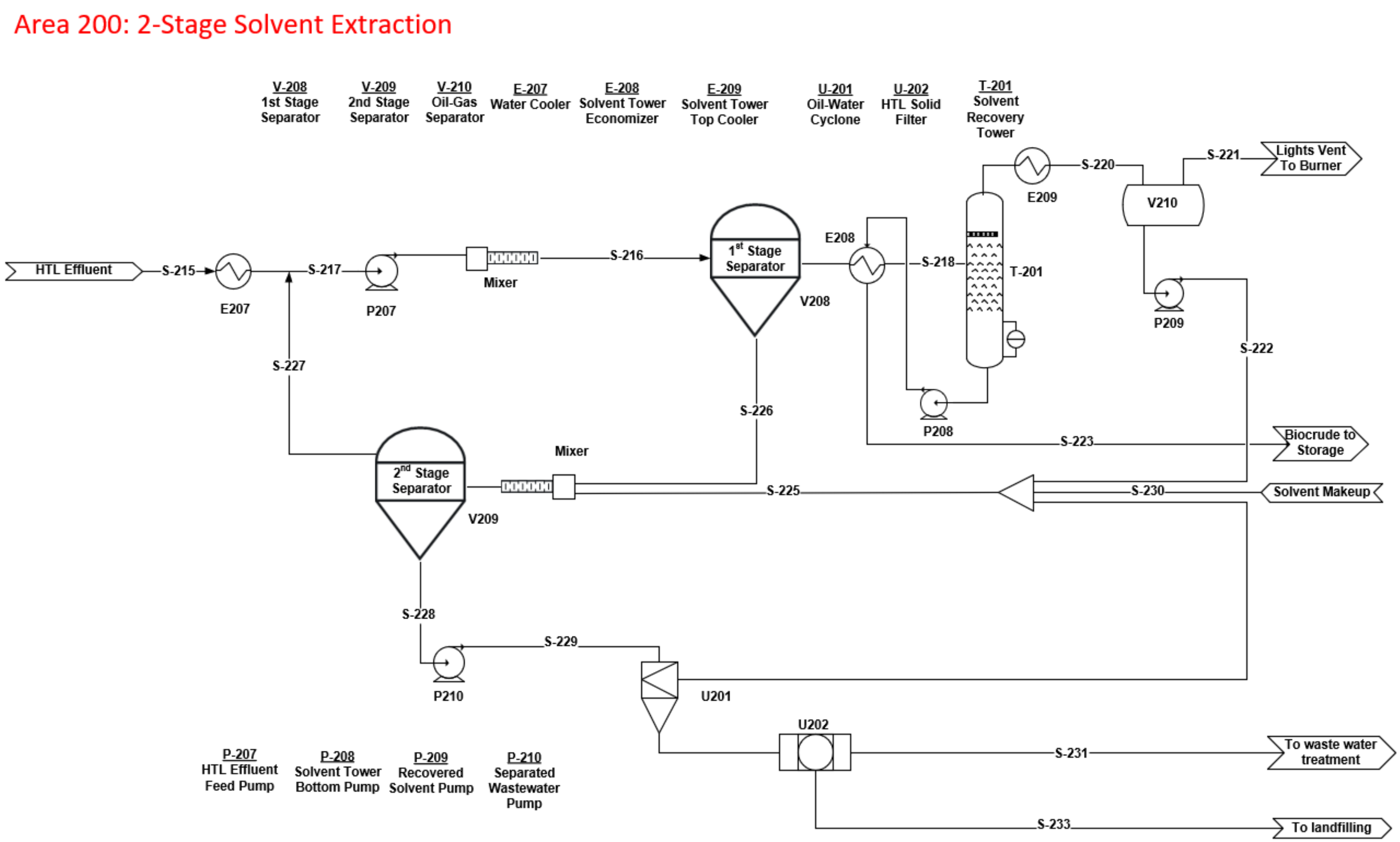

Figure H.3. Solvent Extraction PFD

Stream Name		S215	S-217	S-216	S-218	S-220	S-221	S-222	S-223	S-225	S-227	S-228	S-231	S-233
Total Stream														
Temperature	F	211.4	190.0	166.4	180.0	120.0	80.0	120.1	140.0	248.0	167.6	167.5	211.4	211.4
Pressure	psia	15.0	23.0	23.0	20.0	15.7	100.0	50.0	15.0	20.0	50.0	15.0	15.0	15.0
Mass Flows	lb/hr	30896.2	33387.6	50430.9	19489.1	16857.7	140.0	16857.7	2631.4	47939.5	17043.3	30896.2	25235.8	5660.3
CO2		0.3	0.3	1.1	0.8	0.8	0.0	0.8	0.0	1.1	0.8	0.3	0.3	0.0
H2O		27149.3	27149.3	27177.9	93.9	93.9	0.0	93.9	0.0	27177.9	28.6	27149.3	23793.3	3356.0
H2S		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NH3		103.2	103.2	104.4	1.6	1.6	0.0	1.6	0.0	104.4	1.2	103.2	103.2	0.0
N-C4H10		0.0	0.0	0.3	0.3	0.3	0.0	0.3	0.0	0.3	0.3	0.0	0.0	0.0
N-PENTAN		0.0	0.0	0.3	0.3	0.3	0.0	0.3	0.0	0.3	0.3	0.0	0.0	0.0
ASH		1364.2	1378.0	1378.0	13.8	0.0	0.0	0.0	13.8	1364.2	0.0	1364.2	0.0	1364.2
SOLID		940.1	949.6	949.6	9.5	0.0	0.0	0.0	9.5	940.1	0.0	940.1	0.0	940.1
METHANOL		6.3	6.3	6.6	0.4	0.4	0.0	0.4	0.0	6.6	0.3	6.3	6.3	0.0
ETHANOL		30.6	30.6	34.7	5.4	5.4	0.0	5.4	0.0	34.7	4.2	30.6	30.6	0.0
ACETONE		38.8	38.8	70.6	33.0	33.0	0.0	33.0	0.0	70.6	31.8	38.8	38.8	0.0
ACEACID		384.5	384.5	419.5	47.8	47.8	0.0	47.8	0.0	419.5	35.0	384.5	384.5	0.0
PROACID		166.1	166.5	204.8	49.5	49.0	0.0	49.0	0.4	204.4	38.3	166.1	166.1	0.0
ETHAMIN		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2-PYRRLD		169.6	214.9	243.8	45.7	0.4	0.0	0.4	45.3	198.5	29.0	169.6	169.6	0.0
2-PIPERD		4.2	125.4	143.1	121.4	0.2	0.0	0.2	121.2	21.9	17.7	4.2	4.2	0.0
7-LACTAM		3.6	14.7	18.8	11.2	0.1	0.0	0.1	11.1	7.7	4.1	3.6	3.6	0.0
C5H9NS		114.9	234.6	290.5	120.3	0.6	0.0	0.6	119.7	170.8	55.9	114.9	114.9	0.0
TOLUENE		47.3	0.0	16761.0	16709.4	16616.6	140.0	16616.6	92.8	16808.2	16760.9	47.3	47.3	0.0
RYRO3ETM		0.0	2.5	2.5	2.5	0.0	0.0	0.0	2.5	0.1	0.1	0.0	0.0	0.0
PHENO4M		7.3	87.2	106.6	86.5	6.6	0.0	6.6	79.9	26.7	19.4	7.3	7.3	0.0
AMIPHENO		5.2	6.4	6.9	1.2	0.0	0.0	0.0	1.2	5.7	0.5	5.2	5.2	0.0
INDOLE		0.0	70.0	71.0	70.6	0.6	0.0	0.6	70.0	1.0	1.0	0.0	0.0	0.0
2-PYTENE		0.0	0.4	0.4	0.4	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0
C15OLEF		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MC12AMID		0.0	82.9	83.0	82.9	0.0	0.0	0.0	82.9	0.0	0.0	0.0	0.0	0.0
C16AMIDE		0.0	382.8	382.8	382.8	0.0	0.0	0.0	382.8	0.0	0.0	0.0	0.0	0.0
C18AMIDE		0.0	398.5	398.5	398.5	0.0	0.0	0.0	398.5	0.0	0.0	0.0	0.0	0.0
C16:0FA		0.0	540.9	541.0	540.9	0.0	0.0	0.0	540.9	0.0	0.0	0.0	0.0	0.0
C18:1FA		0.0	58.2	58.2	58.2	0.0	0.0	0.0	58.2	0.0	0.0	0.0	0.0	0.0
HEVOIL1		360.9	386.8	398.0	25.9	0.0	0.0	0.0	25.9	372.2	11.2	360.9	360.9	0.0
HEVOIL2		0.0	79.2	79.2	79.2	0.0	0.0	0.0	79.2	0.0	0.0	0.0	0.0	0.0
C16H1-01		0.0	495.3	497.9	495.2	0.0	0.0	0.0	495.2	2.7	2.7	0.0	0.0	0.0

Area 300: HTL Aqueous Treatment

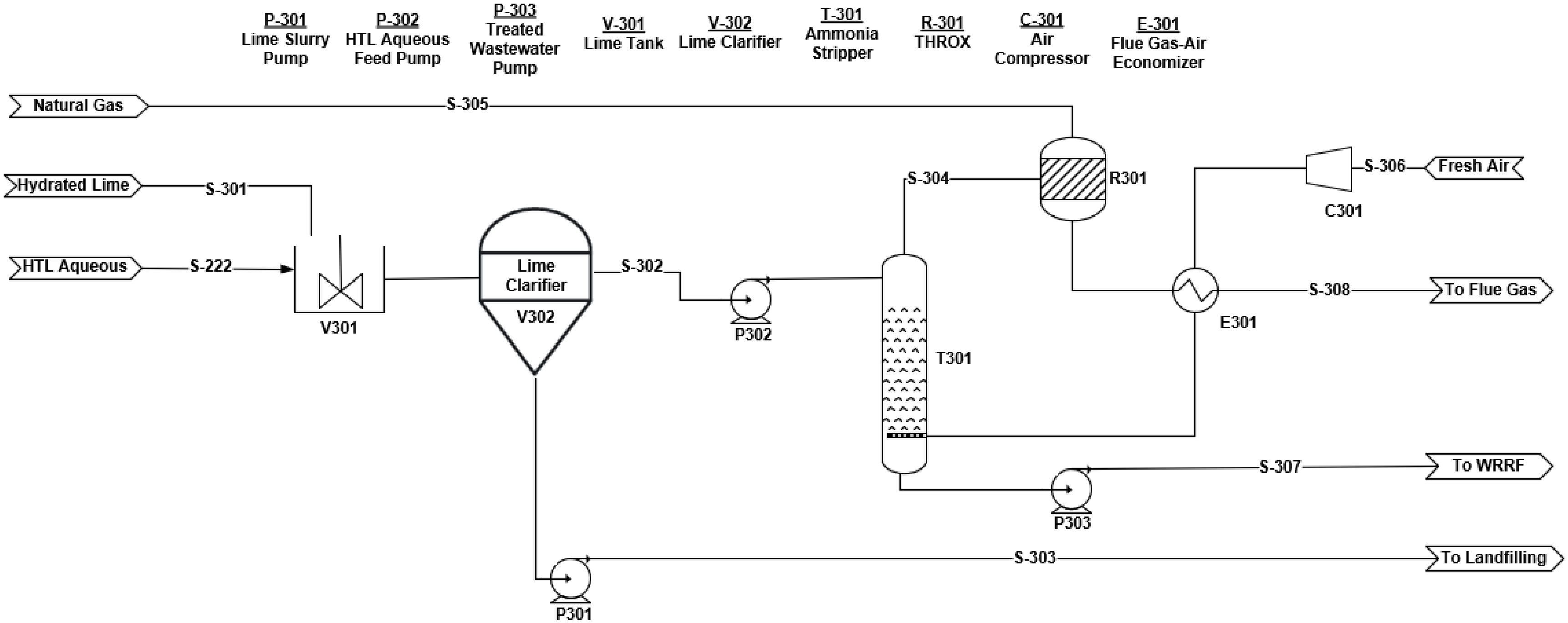

Figure H.4. HTL Aqueous Treatment PFD

Material									
Stream Name	Units	S-301	S-302	S-303	S-304	S-305	S-306	S-307	S-308
Total Stream									
Temperature	F	70.0	140.1	140.7	122.4	70.0	59.0	111.2	367.3
Pressure	psia	14.7	60.0	60.0	14.8	25.0	14.7	14.8	14.7
Mass Flows	lb/hr	66.6	25882.1	116.6	21829.4	20.6	20000.0	24052.7	21850.0
H2O	lb/hr	0.0	24318.4	17.5	1751.8	0.0	126.1	22692.8	2114.1
N2	lb/hr	0.0	0.0	0.0	14981.7	0.0	15009.8	28.1	15087.7
O2	lb/hr	0.0	0.0	0.0	4577.8	0.0	4600.1	22.4	4084.4
AR	lb/hr	0.0	0.0	0.0	253.4	0.0	254.7	1.3	253.4
CO2	lb/hr	0.0	0.0	0.0	8.5	0.0	9.2	0.6	310.3
NH3	lb/hr	0.0	131.5	0.1	128.9	0.0	0.0	2.6	0.0
METHANE	lb/hr	0.0	0.0	0.0	0.0	20.6	0.0	0.0	0.0
METHANOL	lb/hr	0.0	6.8	0.0	3.5	0.0	0.0	3.3	0.0
ETHANOL	lb/hr	0.0	35.9	0.0	23.5	0.0	0.0	12.4	0.0
ACETONE	lb/hr	0.0	59.3	0.0	59.3	0.0	0.0	0.0	0.0
ACEACID	lb/hr	0.0	385.4	0.3	38.8	0.0	0.0	346.7	0.0
PROACID	lb/hr	0.0	166.3	0.1	2.2	0.0	0.0	164.1	0.0
2-PYRRLD	lb/hr	0.0	169.5	0.1	0.0	0.0	0.0	169.4	0.0
2-PIPERD	lb/hr	0.0	4.2	0.0	0.0	0.0	0.0	4.2	0.0
7-LACTAM	lb/hr	0.0	3.6	0.0	0.0	0.0	0.0	3.6	0.0
C5H9NS	lb/hr	0.0	114.8	0.1	0.0	0.0	0.0	114.8	0.0
HEVOIL1	lb/hr	0.0	360.7	0.3	0.0	0.0	0.0	360.7	0.0
K+	lb/hr	0.0	46.1	0.0	0.0	0.0	0.0	46.1	0.0
NA+	lb/hr	0.0	16.1	0.0	0.0	0.0	0.0	16.1	0.0
NH4+	lb/hr	0.0	0.4	0.0	0.0	0.0	0.0	0.4	0.0
CL-	lb/hr	0.0	39.5	0.0	0.0	0.0	0.0	39.5	0.0
SO4--	lb/hr	0.0	6.3	0.0	0.0	0.0	0.0	6.3	0.0
HCO3-	lb/hr	0.0	1.0	0.0	0.0	0.0	0.0	1.0	0.0
CO3--	lb/hr	0.0	13.3	0.0	0.0	0.0	0.0	13.3	0.0
OH-	lb/hr	0.0	3.3	0.0	0.0	0.0	0.0	3.3	0.0
CA3PO4*2	lb/hr	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0
CACO3	lb/hr	0.0	0.0	89.8	0.0	0.0	0.0	0.0	0.0
CA(OH)2	lb/hr	66.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MG(OH)2	lb/hr	0.0	0.0	8.0	0.0	0.0	0.0	0.0	0.0

Appendix I HTL Biocrude & Aqueous Phase Model Composition

HTL organic product is a complex mixture of hundreds of compounds. The number and type of compounds used in the Aspen model to represent HTL biocrude and the associated aqueous phase must reasonably match key properties, such as CHONS, density, heating value, GC/MS data, biocrude SIMDIS data and aqueous COD value. The compounds chosen for the Aspen model are shown in Table I. Note that this list does not imply that these compounds occur in the given percentages in actual HTL biocrude, rather each compound represents a group of compounds that taken together exhibit the bulk properties. Carbon dioxide and ammonia in the aqueous phase form their ionic species in various amounts and types, including $NH4^{+}$, $NH2COO^{-}$, $HCO3^{-}$, CO_3^{2-}. For simplification purposes, ion formation is not simulated in the HTL model, but their pure original compounds are considered.

Table I1. Compounds used to model HTL liquid products (dry ash free)

Model Component Name	Matial Balance Names	Boiling Point, °C	Wt%	MW	C	H	O	N	S
N-METHYLTHIOPYRROLIDONE	C5H9NS	284	3.96%	115.20	5	9		1	1
Biocrude									
Oleic-acid	C18:1FA	360	2.25%	282.47	18	34	2		
n-Hexadecanoic acid	C16:0FA	350	15.62%	256.43	16	32	2		
Palmitamide(Hexadecanamide)	C16AMIDE	419	11.03%	255.44	16	33	1	1	
N-Methyldodecanamide	MC12AMID	360	2.39%	213.36	13	27	1	1	
9-Octadecenamide, (Z)-	C18AMIDE	430	11.49%	281.48	18	35	1	1	
Indole	INDOLE	253	2.21%	117.15	8	7		1	
3-methyl-4-aminophenol	AMIPHENO	293	0.18%	123.15	7	9	1	1	
1H-Pyrrole, 3-ethyl-2,4,5-trimethyL-	RYRO3ETM	219	2.64%	137.22	9	15		1	
Dibenzyl-sebacate	HEVOIL2	459	2.30%	382.50	24	30	4		
Phenol, 4-methyl-	PHENO4M	202	2.53%	108.14	7	8	1		
3,7,11,15-tetramethyl-2-Hexadecene	2-PYTENE	387	19.99%	280.54	20	40			
1-Pentadecene	C15OLEF	268	3.45%	210.40	15	30			
Toluene	Toluene	111	1.19%	92.14	7	8			
Naphthalene, 1,2,3,4-tetrahydro-1,1,6-trimethyl-	C13H18	225	0.92%	174.29	13	18			
Triolein	TRIOL-01	847	3.60%	885.45	57	104	6		
C.-I.-11285	C6H1-01	673	14.27%	262.31	16	14		4	
			100.00%						
Aqueous-phase product									
Water	H2O		8.70%	18.015		2	1		
Methanol	METHANOL		0.32%	32.042	1	4	1		
Ethanol	ETHANOL		1.74%	46.069	2	6	1		
Acetone	ACETONE		3.61%	58.080	3	6	1		
Acetic acid	ACEACID		17.97%	60.053	2	4	2		
propanoic acid	PROACID		7.78%	74.079	3	6	2		
CO2	CO2		14.64%	44.010	1		2		
NH3	NH3		6.20%	17.031		3		1	
2-Pyrrolidinone	2-PYRRLD		10.00%	85.106	4	7	1	1	
2-Piperidinone	2-PIPERD		5.84%	99.133	5	9	1	1	
Caprolactam	7-LACTAM		0.68%	113.159	6	11	1	1	
Heavy1 (531-52-2)	HEVOIL1		18.00%	300.363	19	16		4	
N-METHYLTHIOPYRROLIDONE	C5H9NS		4.52%	115.199	5	9		1	1
			100.00%						

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