

Predesign Report for the WWTP Anaerobic Digestion and Cogeneration Expansion Project

Prepared for

City of Gresham

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Jacobs

Predesign Report for the WWTP Anaerobic Digestion and Cogeneration Expansion Project

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Executive Summary

Introduction

The City of Gresham is interested in completing a preliminary design for the construction of the Gresham Wastewater Treatment Plant (WWTP) Anaerobic Digestion and Cogeneration Expansion, CIPWW00024. The preliminary design scope of work includes assisting the City with defining the scope and phasing of the project with which to proceed to design and construction.

The preliminary design further refines the conceptual design identified in the *Feasibility Study of Expanding Liquid Organic Digestion Capacity, CIP 322100* (Feasibility Study) (Jacobs, 2020), which found that there are payback options for a digestion expansion project that could serve to fulfill Gresham's capacity needs in addition to helping the community by accepting additional HSOW in the region.

The purpose of this predesign report is to define the facilities required to allow the Gresham WWTP to achieve the following goals:

- Provide required digestion capacity and redundancy
- Roughly double the solids processing capacity in terms of:
 - High strength organics processing
 - Biogas production
 - Power generation
- Maintain and expand power generation to retain WWTP net zero status
- Install biogas cleaning to generate renewable natural gas (RNG) with the remaining biogas that is not needed to retain net zero electricity status
- Install power controls for use during utility power outages so that the WWTP system can be isolated from the Portland General Electric (PGE) utility grid and operated in island mode

Alternatives Evaluation

Feedstocks

This assessment built on the Feasibility Study (Jacobs, 2020) to identify additional HSOW available in the region. This effort focused on contacting companies within Gresham's Industrial Pretreatment Program, such as organic waste generated by bakeries, grocery stores, restaurants, and other food manufacturers.

Jacobs consulted with the Gresham WWTP to determine a list of potential organic waste stakeholders in the area. Despite reaching out to each of the businesses in the above lists, only two provided information. Even so, this study did reveal some information about the HSOWs in the area. The next step is to discuss with the City some other potential strategies to reach out to current and future stakeholders in the region.

Digestion

This task involved conducting and documenting an assessment of the existing digestion tank's ability to operate over the long-term at thermophilic temperatures. The assessment outlined upgrades and/or improvements to insulation or other mitigation measures needed to mitigate long-term impacts to the structures such as cracking that may result from operating at higher temperatures.

This task involved qualitatively evaluating different digestion technologies and configurations and selecting the general approach that will be carried forward to the predesign report. For example, analysis included evaluation of the digestion capacity expansion with a single, continuous flow stirred tank reactor (CFSTR), a series of CFSTRs that will approach plug flow, or a plug flow reactor configuration.

An economic evaluation was conducted considering costs to construct and operate a microbial hydrolysis system, changes to the heat balance, and if appropriate, increase/decrease in dewatering costs, decrease in cake storage costs (initial capital costs), and reduction in biosolids land application costs. Microaeration in the digesters was evaluated for reduction of hydrogen sulfide in the biogas prior to the biogas treatment systems. This evaluation was based on information from other facilities and did not involve conducting a site-specific pilot of microaeration, although a potential recommendation of this evaluation could be to conduct a pilot at the Gresham WWTP, which could entail lab-scale testing utilizing the digestion pilot system or a full-scale pilot as part of the next phase of this project.

Renewable Energy

The renewable energy landscape continues to evolve since completion of the Feasibility Study (Jacobs, 2020). Changes have included:

- The Oregon legislature passed Senate Bill 98, which established RNG targets and rules around RNG procurement for all gas utilities in Oregon. Gas utilities can invest in the equipment to process, clean, condition, compress, and interconnect RNG to the local gas distribution network.
- The Climate Protection Program, which is the outcome of the governor's Executive Order on Climate will also dramatically increase the incentive for gas utilities throughout Oregon to procure RNG.

These policies have led Northwest Natural Gas Company (NWN) to be more involved in RNG development and procurement in recent years. In addition, the volume of high-value RNG entering renewable energy markets has steadily increased. Since the original BCE was developed in 2020, it has been updated to include RNG in addition to RE. A hybrid option was also considered that consists of increasing the plant's combined heat and power (CHP) system capacity to produce RE and cleaning the excess biogas to pipeline quality to sell for revenue.

The three options considered in the updated BCE can be summarized as follows:

- Option 1: Renewable Electricity – All biogas used to generate RE with expanded CHP system with 2.2 megawatt (MW) capacity
- Option 2: Renewable Natural Gas – All biogas cleaned to pipeline quality for injection
- Option 3: Hybrid – Base-load CHP system (expanded to 1.2 MW capacity) and clean excess biogas to pipeline quality for injection

At project Workshop 1, the City chose to proceed with the Option 3: Hybrid. The City has the ability to phase in the capital improvements based on funding and to further allow the renewable energy credit programs (both state and federal) to mature and possibly become more certain.

Anaerobic Digestion and Cogeneration Expansion

High Strength Organic Waste Receiving Facility

The WWTP is anticipated to receive FOG and food waste as the two sources of HSOW. The preliminary design assumes that the food waste will be screened and preprocessed into a slurry by others (most likely Oregon Metro) prior to delivery at the WWTP. The HSOW receiving facility is divided into two stations, one for FOG receiving and the other for food waste slurry (FWS) receiving. The FOG receiving station will be expanded and a new FWS receiving station will be added.

The FOG receiving station will continue to operate according to current protocol, but the existing storage tanks will be replaced with two new 30,000-gallon tanks to provide the storage volume needed to accept additional FOG and provide complete storage redundancy. The facility currently receives 15,000 to 20,000 gallons of FOG per day and this is anticipated to increase up to 30,000 gallons.

The new FWS receiving station will be required to accept up to 20,000 lb volatile solids/day or approximately 18,400 gallons of FWS. This station includes the following unit processes:

- A truck unloading connection.
- An unloading pump to transfer the FWS to the storage tanks.
- Two 20,000-gallon storage tanks with individual mixing pump systems providing storage redundancy. This allows all of the feedstock to be stored and delivered to the digesters consistently for the following 24 hours.
- One feed pump to deliver the FWS to the digesters.

Foul air from the FOG and FWS receiving tanks will be treated with carbon canisters by displacing air from filling of the receiving tanks (in-fill). The receiving tanks will be filled one at a time by the truck transfer pump. It has been confirmed that the existing carbon canisters can support the in-fill rate for the new larger tanks being proposed for the FOG Receiving Stations. Unlike the FOG receiving station, the two new FWS receiving tanks will be serviced by only one high-density polyethylene canister with coconut shell carbon filter media. Coalescing filters upstream of each carbon canister are required to separate entrained droplets from the air, keeping the carbon canisters unclogged and clean.

Anaerobic Digestion

Existing Facilities

The digestion process at the Gresham WWTP includes two 1,000,000-gallon digesters operating at mesophilic temperatures (95 to 98 degrees Fahrenheit [°F]). The digesters are operated in a series configuration, where all of the feed is directed to Digester 1 and then transferred by gravity to Digester 2. Digester 1 has a fixed cover, whereas Digester 2 has a floating cover, which is typically used for gas storage. Both tanks are mixed using a 20-horsepower linear motion mixer, each with a variable frequency drive (VFD). The existing digesters and Digester Control Building were identified as having structural and nonstructural seismic deficiencies in the resilience assessment performed by Carollo Engineers as part of the *City of Gresham Wastewater Seismic Resilience Plan*, June 2019.

New Facilities/Modifications to Existing Facilities

As part of this project, the new 1,000,000-gallon digester will include the following:

- Operate at thermophilic temperatures (130 to 135°F)
- Cast-in-place or post-tensioned concrete
- Fixed carbon steel cover with maintenance platform
- Digester mixing system – linear motion mixer to optimize volatile solids reduction and gas production
- Digester withdrawal - Sludge withdrawal from Digester 3 will be from either the liquid surface, digester side wall, or the bottom of the cone.
- Emergency overflow lines will be located on all the digesters.

A hybrid geometry for Digester 3 is being proposed that would still offer some of the operational benefits of a silo digester, but would balance performance against these other practical limitations. A new Digester Control Building will be constructed next to Digester 3 and will house the digester heating and recirculation system as well as the digester withdrawal system.

The existing two digesters will be converted to operate at thermophilic temperatures. The covers for the existing digesters will be replaced with fixed carbon steel covers and insulated. The existing linear motion mixers will be retrofitted to be able to operate at the thermophilic temperatures. A structural model was developed to analyze the capability of the reinforced concrete walls to resist the increased stresses and to stay within the stress limits required for crack-control of the concrete. The analysis determined that the

existing concrete walls could accommodate these higher operating temperatures without requiring any supplemental reinforcing or additional insulation.

The digesters will be configured to operate in parallel regardless of the number of digesters in service, and provisions are included to allow transfer between the digesters.

Digester Heating and Recirculation

Digested sludge heat exchangers are required to heat sludge to thermophilic temperatures and maintain digester temperatures due to heat loss through the shell. The heat exchangers will use sludge recirculation and hot water recirculation to maintain the digester contents within the required temperature range. Solids will be withdrawn directly from the tank where sludge circulation pumps will convey the solids through a heat exchanger before the solids are returned to the digester.

No modifications or upgrades to the heat exchanger and sludge recirculation pumps are required for converting the existing digesters to thermophilic operations. The insulation for existing digesters requires no modifications for thermophilic temperatures.

Nitrogen Feed Connections

Digester 3 will be equipped with a nitrogen gas connection. The nitrogen gas connection will allow staff to backflush the headspace of the tank when putting it back in service. Backflushing prevents the possibility of creating an explosive mixture of methane and oxygen during these events.

Dewatering Feed Tanks and Heat Recovery

Two new dewatering feed tanks are included in the design. The dewatering feed tanks will be located to the west of the new Digester 3 Control Building and will provide a storage volume to allow operational flexibility when the dewatering process is offline; it will also allow for digested sludge heat recovery prior to dewatering, which will help prevent the stored biosolids from becoming too odorous.

Gas System Analysis

Storage

The use of a low-pressure gas holder bubble is desired to buffer fluctuation in digester gas production and use in cogeneration engines, hot water boilers, and RNG system. The gas holder includes level and pressure instrumentation to provide a dampened signal to be used for controlling digester gas usage equipment loading. The gas storage membrane will be controlled to maintain a near constant pressure adapting to changes in gas production. This will allow the downstream gas equipment (pretreatment and gas usage equipment) to be operated at a near constant setpoint and remove the need for the equipment to ramp up and down based on the gas production rates.

Pretreatment

Digester gas needs to be treated to protect the combustion equipment and the current system is undersized for the facility gas production. A new digester gas treatment system will be installed to serve the new engines, boilers, and RNG system. At this time, no equipment supplier has been selected, but the included basis of design is based on conversations with Greenlane Renewables and Unison Solutions, LLC.

The digester gas treatment system will be sized for an initial facility annual average startup flow of 370 standard cubic feet per minute (scfm) and a peak future flow of 640 scfm through a single treatment train. The digester gas treatment system will consist of three major processes: hydrogen sulfide (H₂S) removal via media adsorption, moisture reduction, and siloxane and volatile organic compound removal via activated carbon adsorption.

Renewable Natural Gas Treatment

Cleaning digester gas to pipeline quality for injection into the grid requires further treatment of the pretreated digester gas to remove any residual oil, moisture, and the carbon dioxide (CO₂) content. Also required is additional gas compression, gas constituent analyzer, carbon polishing, controls, and an enclosure for outdoor installation.

It is proposed to utilize a 3-stage membrane system configured into two treatment trains to provide the necessary turndown for the low flow scenario and also be able to process the peak RNG flow. The information included here is based on Unison Solutions, LLC. Conversations have also taken place with Greenlane Renewables based on a pressure swing adsorption system (PSA). The PSA system would struggle to meet the low flow scenario and is less expandable than the membrane system; therefore, the information contained herein is based on the membrane system.

Waste Gas Burner

Currently, the facility has two waste gas burners onsite. The older waste gas burner has exceeded its useful life and will be demolished as part of this project. The newer flare is a candlestick flare and sized for 1,040 scfm, significantly more than the anticipated future digester gas production. To avoid modifications to the existing flare, the boilers could be used to combust upgraded gas rather than the flare.

Cogeneration

Existing Facilities

The WWTP currently produces heat and electricity onsite using a 395-kilowatt (kW) cogeneration engine installed in 2005 and a 403-kW cogeneration engine installed in 2015. A standby boiler provides backup heat and a 360-kW photovoltaic array (AC side of inverters) provides additional power generation.

The cogeneration system generally produces enough electricity to power the WWTP, with the photovoltaic array generally filling in any gaps in production versus consumption. WWTP power and heating requirements are expected to increase with digester and other upgrades. Therefore, the existing cogeneration system will be replaced to accommodate these additional demands.

New Facilities

The new cogeneration system will house two 600-kW nominal cogeneration engines. The WWTP heating and power demands are projected to increase with the proposed digestion upgrades. The engine rooms are laid out with two 600-kW cogeneration units, but an 800-kW unit would fit in the same space. The cogeneration facility will consist of an engine room, an electrical room, and a small control room. The new boilers and heating water main loop pumps will be located in the new Digester Control Building. The heating water loop will connect to the engine heat recovery heat exchangers and pumps inside the engine room. Waste heat not recovered by the heating water system will be automatically rejected to radiators located adjacent to, or on the roof of, the cogeneration facility.

The engines will meet federal emissions requirements for biogas-fueled engines through use of oxidation catalysts to oxidize carbon monoxide, unburned hydrocarbons, and volatile organic compounds. It is not anticipated that further exhaust treatment (e.g., selective catalytic reduction system for further NO_x reduction) will be required based on current regulations.

Hot Water Loop System

Heating water for digesters as well as for building heat will be provided by a common heating water system. Heating loads include the digesters, FOG heating, biogas treatment, existing digester facility heating, ventilation, and air conditioning (HVAC), Administration Building HVAC, Solids Building HVAC, headworks HVAC, Maintenance Building HVAC, and the new proposed digester facility HVAC.

Heat is recovered by the cogeneration engines and two duty boilers with a standby boiler. The boilers will be provided with separate gas trains to allow them to be fired from treated digester gas or natural gas.

Two primary loop pumps ,will be provided in a duty/standby arrangement and will be located in the new Digester Control Building. These pumps will be VFD driven so flow can be adjusted to the actual heat load for energy savings over a constant flow primary loop. The secondary loop pumps will be constant speed with three-way valves adjusting the heat input to the secondary loops. No standby pumps are provided for secondary loops.

Heat Exchangers

Digested sludge heat exchangers are required to heat sludge to thermophilic temperatures and maintain digester temperatures due to heat loss through the shell. The heat exchangers will use sludge recirculation and hot water recirculation to maintain the digester contents within a temperature range. The existing sludge tubes in tube heat exchangers for Digesters 1 and 2 are anticipated to remain in service and operate at thermophilic temperatures. A spiral heat exchanger is recommended for Digester 3 and will be installed in the Digester 3 Control Building.

Pumping

The primary and secondary loop pumps will be designed for flow rates corresponding to the heat loads and design loop temperature change of 20°F for process loads and 30°F for new HVAC loads. The existing HVAC secondary loop flow rate and design temperature change will remain unchanged to avoid modifications in other facilities and existing yard piping. The existing WWTP HVAC heating water pumps will remain unmodified. These pumps could be optimized to operate at a lower flow rate if the temperature drops across the individual heat loads are re-evaluated and increased.

Boilers

The existing boiler in the existing Digester Control Building will remain in service. Two new boilers will be installed in the new Digester 3 Control Building. Alternatively, if the cogeneration project is installed at the same time as the digestion expansion project, the new boilers could be installed inside the room where the existing cogeneration engines are located. Preliminary design criteria were developed for the boilers.

Biosolids Storage

Expansion of the existing biosolids storage facility is proposed to meet the 60 days of biosolids storage desired. Modifications include extending the existing facility, such that a new truck loading lane will extend from the existing truck loading lane, eight additional storage bins will be constructed with a service bay in the center, a small unloading area for front loaders will be constructed on the north end of the facility. This modification will double the existing storage capacity from approximately 3,650 cubic yards to 7,280 cubic yards and provide additional operational flexibility. Due to the steep grade in the area north of the existing biosolids storage facility, significant earthwork and regrading will be required, and a retaining wall will be required to bring the grade level to the proper elevation for the unloading area.

Wastewater Liquids Treatment System Impacts

The WWTP receives domestic, commercial, and industrial wastewater from incorporated areas of Gresham, Wood Village, and Fairview. Co-digestion of additional organic waste, specifically FWS, would result in additional ammonia and organic load being recycled through the WWTP via the dewatering filtrate recycle stream. This recycle stream is diverted to the lower plant only. The model results indicate that the effluent ammonia concentrations would increase with co-digestion of additional organic waste and the process impacts will need to be further evaluated to ensure compliance with the NPDES permit for effluent ammonia.

Electrical Power Plan (including Utility Connection and Microgrid)

The following list indicates new facilities or electrical loads that require power, along with the recommended approach for providing power:

- New digester and associated control building: New MCC located in control building will be powered from new 480 V switchgear in the new Cogeneration Building.
- New cogeneration facility: New 480 V switchgear will connect cogeneration units. Switchgear will feed MCCs for all other loads.
- Expanded biosolids storage: A new 480 V feeder will be provided from the new Cogeneration Building.
- Gas treatment systems: One or more 480 V feeders will be provided from the new Cogeneration Building.
- FOG/FWS receiving area improvements: Power to these areas will be from existing power sources, likely within the existing digester control building.

A microgrid can benefit the WWTP in a number of ways, providing a more reliable and sophisticated power system. Major components of a typical microgrid include generation sources (cogeneration, diesel generators, solar, etc.), a battery, distribution equipment (switchgear and wiring), and a control system that governs the generation assets and communicates with the WWTP control system for load control. There are many configurations and operating principles, but inherent in any microgrid system is the ability to isolate from a larger electrical grid and run as "Island."

The WWTP already has cogeneration, solar generation assets, and a 12.47 kV in-plant power network that connects to all generation sources and loads. The addition of a battery (with microgrid controller) or a 1 MW diesel generator, along with relocation of the cogeneration intertie, would allow the WWTP to implement a microgrid that allows the cogeneration units (and potentially the solar array) to directly power the WWTP power network. The microgrid would be classified as a "physical, non-utility owned microgrid."

Due to the higher capital costs and limited financial benefit of a more resilient, battery-based microgrid, something similar to Microgrid Configuration 1 from the Energy Trust of Oregon analysis is recommended to be implemented in the near term for the WWTP.

Geotechnical Site Needs Assessment

The general subsurface soil profile is described here based on the geotechnical data from the existing geotechnical explorations, and a review of the regional geologic conditions:

- Fill consisting of loose to medium dense silty sand (SM) and soft to medium stiff silt, silt with sand, and sandy silt (ML) with occasional gravel and construction debris. This layer is underlain by the alluvium or by weathered Troutdale Formation.
- Alluvium consisting of brown loose to medium dense silty sand (SM) and firm to stiff non-plastic silt (ML) was encountered in certain borings. This unit is present overlying the Troutdale Formation.
- Troutdale Formation consisting of lightly to strongly cemented poorly graded sand (SP), poorly graded sand with silt (SP-SM), well graded sand (SW), and poorly graded gravel (GP). This unit underlies either the fill or the alluvium layer.

The historical groundwater data indicate that in the vicinity of the new digester 3 the groundwater is at about 23 feet below ground surface in the very dense Troutdale Formation. Data of the seasonal variability of groundwater are limited.

The proposed geotechnical exploration program consists of eleven borings at the new facility locations, two of which will include standpipe piezometers including vibrating wire piezometers. Standard penetration test (SPT) N-values will be documented and laboratory testing of SPT samples conducted for physical analysis of selected samples.

Currently, shear wave velocity data are not available at the project site. The proposed geotechnical investigation will include measurement of shear wave velocity using geophysical methods for soil site classification for the project area per American Society of Civil Engineers (ASCE) 7-22, Chapter 20 (ASCE, 2022). The site class will be used for the assessment of the geotechnical seismic hazard for the project.

Permitting

Building Codes

Permitting of project improvements is anticipated to occur under the 2022 Oregon Structural Specialty Code (OSSC), both for new facilities and modifications to existing structures. Based upon preliminary evaluations, it is expected that the existing structures to be modified will meet the requirements for work area compliance under the OSSC without need for extensive upgrades. However, the existing FOG tank foundations are an exception. Meeting the design requirements for seismic load resistance will require replacement of the existing foundations due to the higher overturning demands from the larger tanks in addition to the limited space available.

For concrete structures, structural design for WWTP facilities typically requires tighter limits on reinforcing steel stresses under service loads than required by the OSSC to keep crack widths small. This is done to reduce the potential for corrosion of the reinforcing steel. The preliminary analyses performed indicate that the existing digesters can be converted to operate under thermophilic conditions without wall retrofits. Reinforcing steel stresses fall within the range allowed by American Concrete Institute 350 for normal environmental exposures, acceptable for the levels of pH and sulfates at which anaerobic digesters perform acceptably.

Compliance with the 2021 Oregon Energy Efficiency Special Code (OEESC) is also required for new elements of alterations. However, alterations up through Level 3 do not require the entire building or structure to conform to the energy requirements of the OEESC.

NFPA-820 Compliance

The existing Digester Control Building built in 1987 does not meet the current National Fire Protection Association (NFPA) 820 code. To comply with the current NFPA 820 code, the building would require modifications to the HVAC systems to prevent potential of explosion hazards caused by the proximity to the anaerobic digesters. To reduce the risk of ignition in these classified areas, explosion-proof equipment can be purchased, but because ignition can still occur from transient sources, it is best to protect the facility from explosion classifications through physical separation and proper ventilation. To accomplish this, all existing openings within 10 feet of the existing digesters will be required to be sealed. All new openings will be located outside the 10-foot-wide classified areas. This requirement applies to openings for both supply and exhaust, as well as louvers and doors. Proposed modifications were identified in the preliminary design drawings.

Air Permitting Review

The project includes expanding the WWTP's high strength organic digestion capacity. Preliminary design includes the following equipment that have an impact on air quality:

- New odor controls
- Modifications to existing digesters
- A new anaerobic digester
- Replacement of an existing flare with a new flare
- Additional digester gas powered cogeneration
- New boilers
- A new biogas cleaning system

The combustion equipment is subject to air quality permitting review, but all equipment contributes to the facility meeting its Plant Site Emission Limit (PSEL), visible emissions and nuisance requirements.

Permitting requirements include addressing Oregon Department of Environmental Quality (DEQ) procedures; state regulations (facility-wide requirements, Clean Air Oregon Rule, registration and reporting of greenhouse gases, and land use compatibility statement); and federal regulations (New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants).

Projected Schedule, Constraints, and Phasing

It is understood that these improvements will likely need to be constructed through a phased sequence of separate projects. In order to allow continued operation of the solids facilities, it will be critical that during design each project identify the constraints the contractor will need to follow to minimize disruption to the normal WWTP operations. If all these facilities were to be constructed as one project, it is anticipated that the overall duration of construction could be 24 to 36 months due to the sequential construction requirements for this project.

The following project phasing is recommended but could be modified based upon available funding:

- Phase 1 (Digestion Expansion)
 - Relocate 30-inch-diameter PE and 8-inch-diameter WAS lines
 - Construct new thermophilic digester (existing digesters continue to operate at mesophilic temperatures)
 - Construct new Digester Control Building
 - Construct new dewatering feed tanks
- Phase 2 (Existing Digester Upgrades)
 - Construct gas storage facility
 - Existing Digester 1 and 2:
 - Replace covers
 - Convert to thermophilic operation
 - Construct required seismic retrofits
 - Existing Digester Control Building:
 - Upgrade ventilation and monitoring system to comply with NFPA-820 guidelines
 - Construct required seismic retrofits
- Phase 3 (High Strength Organic Waste and Biosolids Storage Expansion)
 - Demolish existing waste gas burner
 - Expand HSOW (FOG and FWS) receiving infrastructure
 - Expand biosolids storage
- Phase 4 (Cogeneration Facility)
 - Construct new cogeneration facility
 - Construct digester gas treatment facility
 - Construct RNG treatment facility
 - Install microgrid system with diesel or battery back-up

The Phase 1 project is required to be completed and online before any of the other projects begin. The other three phases could be constructed concurrently but should be brought online in the order presented.

Economic Model Update

A Class 4 cost estimate was completed as part of the Anaerobic Digestion and Cogeneration Expansion project and is included in Appendix E. The capital costs were separated into the four potential project phases. The costs include 24 percent for engineering, legal, and administrative (ELA) costs but does not include the 14 percent Gresham administration fee.

- Phase 1 (Digestion Expansion) – \$16.4 million
- Phase 2 (Existing Digester Upgrades) – \$12.2 million
- Phase 3 (High Strength Organic Waste and Biosolids Storage Expansion) – \$10.2 million
- Phase 4 (Cogeneration Facility) – \$27.8 million
- Grand Total – \$66.6 million

The business case evaluation that was completed as part of the alternatives evaluation and included in Appendix A-4 was updated with the capital cost for hybrid Option 3a from the cost estimate. The results indicate that the Option 3a hybrid offers a potential 7 to 16 year payback on a capital project that is both needed for capacity expansion and produces renewable energy and reduces FOG/FW disposal in landfills.

Next Steps

The predesign has shown that it is beneficial for the City to continue exploring the feasibility of accepting additional liquid organic waste at the Gresham WWTP. There are payback options for a digestion expansion project that could serve to fulfill Gresham's capacity needs in addition to helping the community by accepting additional liquid organic waste in the region. Next steps are as follows:

- Explore and secure sources of funding for the project.
- Continue collaboration with Metro, Energy Trust, and the Oregon Department of Energy.
- Decide on phasing and scope that will be included in the detailed design phase.
- Further evaluate industrial sources of liquid organic waste as a potentially viable future source.
- Collaborate with the City of Portland identifying sources of liquid organic waste in the Portland Metro Area.
- Continue discussion with PGE and DEQ to determine path forward with the Oregon Clean Fuels Program (CFP) and the California Low Carbon Fuel Standard (LCFS). Gresham intends to utilize the Oregon program assuming CFP rules are finalized and incentives are favorable/comparable to the LCFS.
- Continue to monitor changes to the U.S. Environmental Protection Agency Renewable Fuel Standard Program (RFS).
- Install piezometer at third digester location and gather groundwater elevation data to enable optimized design of digester geometry.
- Anticipated schedule:
 - Design complete in fiscal year (FY) 23/24
 - Construction: FY 24/25 and FY 25/26
 - Project online, begin accepting additional liquid organic waste: 2026

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Acronyms and Abbreviations

°F	degrees Fahrenheit
A	ampere
AACE	Association for the Advancement of Cost Engineering
ACH	air changes per hour
ACDP	Air Contaminant Discharge Permit
ASCE	American Society of Civil Engineers
BCE	business case evaluation
Btu/hr	British thermal units per hour
Btu/scf	British thermal units per standard cubic foot
Btu/hr-sf-°F	British thermal units per hour-square foot-degrees Fahrenheit
CAO	Cleaner Air Oregon
cfm	cubic feet per minute
CFP	Clean Fuels Program
CFR	<i>Code of Federal Regulations</i>
CFSTR	continuous flow stirred tank reactor
CHP	combined heat and power
DEQ	Oregon Department of Environmental Quality
ELA	engineering, legal, and administrative
EPA	U.S. Environmental Protection Agency
ETO	Energy Trust of Oregon
FOG	fat, oil, and grease
FWS	Food waste slurry
gpm	gallons per minute
HAP	hazardous air pollutant
HDPE	High-density polyethylene
hp	horsepower

HSOW	High strength organic waste
HVAC	heating, ventilation, and air conditioning
IPP	Industrial Pretreatment Program
kV	kilovolt
kVA	kilovolt-ampere
kW	kilowatt
kWh	kilowatt-hours
lb	pounds
LCFS	Low Carbon Fuel Standard
MACT	Maximum Achievable Control Technology
MBH	1,000 British thermal units per hour
MCC	motor control center
MHP	microbial hydrolysis
MMBtu/hr-HEX	million British thermal units per hour per heat exchanger
MW	megawatt
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NSPS	New Source Performance Standards
NWN	Northwest Natural Gas Company
OAR	Oregon Administrative Rules
OEESC	Oregon Energy Efficiency Special Code
OSSC	Oregon Structural Specialty Code
PE	primary effluent
PGE	Portland General Electric
PLC	programmable logic controller
ppd	pounds per day
ppm	parts per million

PSA	pressure swing adsorption system
PSEL	Plant Site Emission Limit
psi	pounds per square inch
RE	renewable electricity
RFS	Renewable Fuel Standard Program
RNG	renewable natural gas
SCADA	supervisory control and data acquisition
scfm	standard cubic feet per minute
SIU	Significant Industrial User
SPT	standard penetration test
TACT	Typically Achievable Control Technology
TBD	To be determined
V	volt
v/v	volume to volume
VFD	variable frequency drive
VS	volatile solids
WAS	waste activated sludge
WC	water column
WWTP	wastewater treatment plant

1. Introduction

1.1 Project Overview

The City of Gresham is completing a preliminary design for the Anaerobic Digestion and Cogeneration Expansion, CIPWW00024 project at the Gresham Wastewater Treatment Plant (WWTP). The preliminary design scope of work includes assisting the City with defining the scope and phasing of the project with which to proceed to design and construction.

The preliminary design further refines the conceptual design identified in the *Feasibility Study of Expanding Liquid Organic Digestion Capacity, CIP 322100* (Feasibility Study) (Jacobs, 2020), which found that it is beneficial for the City to continue exploring the feasibility of accepting additional high strength organic waste (HSOW) at the Gresham WWTP. The feasibility study showed that there are payback options for a digestion expansion project that could serve to fulfill Gresham's capacity needs in addition to helping the community by accepting additional HSOW in the region.

The Gresham WWTP has operated cogeneration since 2005, accepted and co-digested fat, oil, and grease (FOG) since 2012, and achieved net zero since startup of the second cogeneration engine in 2015. The Gresham WWTP digesters are currently at capacity for accepting FOG and in need of increasing digestion capacity per current and projected loadings in the *Gresham Wastewater Treatment Plant Master Plan Update 2017* (2017 Master Plan) (CH2M, 2017).

The purpose of this predesign report is to define the facilities required for the Gresham WWTP to achieve the following goals:

- Provide required digestion capacity and redundancy
- Roughly double the solids processing capacity in terms of:
 - High strength organics processing (volatile solids per day [VS/day])
 - Biogas production (standard cubic feet per day)
 - Power generation (kilowatt-hours [kWh])
- Maintain and expand power generation to retain WWTP net zero status with cogeneration engines
- Install biogas cleaning to generate renewable natural gas (RNG) with the remaining biogas that is not needed to retain net zero electricity status
- Install power controls for use during utility power outages so that the WWTP system can be isolated from the Portland General Electric (PGE) utility grid and operated in island mode

This preliminary design includes designing the project to approximately 20 percent of this assumed project scope. The improvements identified to allow the Gresham WWTP to achieve the above stated goals are:

- Construct a third, thermophilic anaerobic digester and digester control facility, including dewatering feed tanks to allow heat recovery from digested sludge
- Convert the existing mesophilic digesters to thermophilic operations
- Convert Digester 2 from floating cover to fixed cover and install low pressure storage for biogas pressure control
- Expand the high strength organic receiving infrastructure for FOG and provide new receiving infrastructure for food waste slurry (FWS)
- Demolish one of two existing flares
- Construct a cogeneration facility for engines with capacity to provide 1,200 kilowatts (kW) of combined heat and power, with capabilities to restart and operate in island mode

- Install additional gas treatment systems that will allow the biogas to be cleaned to suitable standards for operation of the cogeneration equipment and additional systems that will clean excess biogas to RNG standards
- Expand the existing biosolids storage facility for additional storage

The City plans to replace the two existing belt filter presses with new dewatering equipment (either centrifuges or screw presses that will be located in the existing Solids Building) under a separate, early-out project, and, therefore, those improvements are not included in the scope of this predesign report.

1.2 Report Organization

This predesign report is organized to review the alternatives evaluated in the development of this design, describe the elements of the selected anaerobic digestion and cogeneration project, present the economic model updates, provide preliminary design drawings for the project, and list associated predesign references.

This predesign report is supported by the following appendixes:

- A. Alternative Evaluation Documentation:
 - A-1: High Strength Organic Material Market Assessment
 - A-2: Digestion Technology Update
 - A-3: Renewable Energy Update
 - A-4: Power Utility Coordination & Preliminary Economic Model Update
 - A-5: Capital Funding Assessment
- B. Discipline Technical Memorandums
 - Architectural
 - Corrosion Control
 - Electrical
 - Geotechnical
 - Heating, Ventilation, and Air Conditioning; Plumbing; Fire Protection
 - Instrumentation and Controls
 - Mechanical
 - Site Civil and Yard Piping
 - Structural
- C. Drawings
- D. Major Equipment List
- E. Capital Cost Estimate

2. Alternatives Evaluation

2.1 High Strength Organic Material Market Assessment

The Gresham WWTP has conducted an initial HSOW market assessment to provide an updated assessment of potential HSOWs that may be available to process in an expanded anaerobic digester facility and ultimately, generate more renewable energy. Under Task 2.3 – Feedstock Market and Pre-processing Approach Update of this project, this effort focused on contacting companies within Gresham’s Industrial Pretreatment Program (IPP) and was not intended to be a comprehensive review of all potential HSOW generators in the Portland metropolitan area. The potential HSOW streams that were considered as part of this market assessment include organic waste generated by bakeries, grocery stores, restaurants, and other food manufacturers.

Additional efforts will be discussed with the City and may be completed to aid in the data evaluation as the design progresses.

Jacobs consulted with the Gresham WWTP to determine a list of potential organic waste stakeholders in the area. IPP permittees were the focus of this effort and included the following companies:

- Teeny Foods
- Portland Specialty Baking
- Trailblazer Foods
- Eclair Farm
- Migration Brewing
- Townsend Farms
- Imperial Yeast

Despite reaching out to each of the businesses in the above lists, only Teeny Foods and Portland Specialty Baking provided information. Trailblazer food specified that they were not interested in responding to the questionnaire provided. For more information regarding the information collected, see the *High Strength Organic Material Market Assessment Technical Memorandum* (Jacobs, 2022a) (copy provided in Appendix G).

While this study did reveal some information about the HSOWs in the area, there were some important limitations. The first limitation was a lack of responsiveness from the businesses. This effort was focused on specific potential HSOW producers identified in the Gresham IPP. Of that subset, there was a limited response, meaning that definitive conclusions are not currently possible. The next step is to discuss with the City some other potential strategies to reach out to current and future stakeholders in the region.

From this study, it appears that Portland Specialty Bakery is currently not interested in changing who they work with, while Teeny Foods could be convinced if economically feasible. Another important finding is that some of the waste is likely already going to the Gresham WWTP, either through the sanitary sewer or via the current FOG receiving program. In terms of potential biochemical oxygen demand loading for co-digestion that could be diverted or hauled to the Gresham WWTP, approximately 1,200 pounds per day (ppd) of waste was identified.

2.2 Digestion

This task involved conducting and documenting an assessment of the existing digestion tank’s ability to operate over the long-term at thermophilic temperatures. The assessment outlined upgrades and/or improvements to insulation or other mitigation measures needed to mitigate long-term impacts to the structures such as cracking that may result from operating at higher temperatures.

This task involved qualitatively evaluating different digestion technologies and configurations and selecting the general approach that will be carried forward to the predesign report. For example, analysis included evaluation of the digestion capacity expansion with a single, continuous flow stirred tank reactor (CFSTR), a series of CFSTRs that will approach plug flow, or a plug flow reactor configuration. Class A biosolids through digestion was also analyzed as a potential design criteria parameter.

An economic evaluation was conducted considering costs to construct and operate a microbial hydrolysis system, changes to the heat balance, and if appropriate, increase/decrease in dewatering costs, decrease in cake storage costs (initial capital costs), and reduction in biosolids land application costs.

Microaeration in the digesters was evaluated for reduction of hydrogen sulfide in the biogas prior to the biogas treatment systems. This evaluation was based on information from other facilities and did not involve conducting a site-specific pilot of microaeration, although a potential recommendation of this evaluation could be to conduct a pilot at the Gresham WWTP, which could entail lab-scale testing utilizing the digestion pilot system or a full-scale pilot as part of the next phase of this project.

Further details about the digestion alternative are included in *Task 2.4 – Digestion Technology Update* (Jacobs, 2023a) (copy provided in Appendix H).

2.3 Renewable Energy

The City performed a Feasibility Study (Jacobs, 2020) to determine if they should accept additional FOG and food slurry that will be diverted from landfills by the Metro Commercial Food Scraps Policy. The existing digesters are at capacity and could not accept any more additional organic waste loading. However, with the expansion of the digestion capacity included in the study, the WWTP could process an additional 30,000 pounds volatile solids per day (lb VS/day) of additional HSOW loading. The additional ppd of volatile solids would also produce more biogas, which could be used to generate revenue through either renewable electricity (RE) or RNG. This approach would aid the City in going beyond net zero for energy consumption. The BCE carried out in the study showed a promising payback period for RE options, especially if grant funding is available to offset upfront capital investment. The next steps included a more detailed predesign of the recommended project.

The renewable energy landscape continues to evolve since completion of the Feasibility Study (Jacobs, 2020). Changes have included:

- The Oregon legislature passed Senate Bill 98, which established RNG targets and rules around RNG procurement for all gas utilities in Oregon. Senate Bill 98 sets the policy framework for gas utilities to buy RNG and deliver it to their customers for residential, commercial, and industrial needs, such as space and process heating. There are not requirements to put the RNG into compressed natural gas vehicles. This bill is completely separate from the Oregon Clean Fuels Program and the federal Renewable Fuel Standard.
- Senate Bill 98 allows natural gas utilities to both procure RNG under long-term contracts and invest in RNG production. Gas utilities can invest in the equipment to process, clean, condition, compress, and interconnect RNG to the local gas distribution network. These investments can be rate-based and can be made both in Oregon and outside of Oregon.
- The Climate Protection Program, which is the outcome of the governor's Executive Order on Climate will also dramatically increase the incentive for gas utilities throughout Oregon to procure RNG.

These policies have led Northwest Natural Gas Company (NWN) to be more involved in RNG development and procurement in recent years. NWN has been executing contracts to purchase RNG under long-term fixed-price contracts and is investing in RNG production and has several projects where they are providing the capital to pay for the RNG cleaning, conditioning, and compression equipment, as well as the pipeline interconnection.

In recent years, the volume of high-value RNG entering renewable energy markets has steadily increased. Since the original BCE was developed in 2020, it has been updated to include RNG in addition to RE.

A hybrid option was also considered that consists of increasing the plant's combined heat and power (CHP) system capacity to produce RE and cleaning the excess biogas to pipeline quality to sell for revenue. The results from the BCE will help confirm the preferred alternative.

The three options considered in the updated BCE can be summarized as follows:

- Option 1: Renewable Electricity
 - All biogas used to generate RE with expanded CHP system with 2.2 megawatt (MW) capacity
- Option 2: Renewable Natural Gas
 - All biogas cleaned to pipeline quality for injection
- Option 3: Hybrid
 - Base-load CHP system (expanded to 1.2 MW capacity) and clean excess biogas to pipeline quality for injection

At project Workshop 1, the City chose to proceed with the Option 3: Hybrid approach for the following reasons:

- The renewable energy credit markets are under development and many of the assumptions herein may continue needing to be revised. The sensitivity analyses presented in this report demonstrate that the path the City chooses—RE, RNG, or some combination—is highly sensitive to these credit markets. So having the flexibility of remaining open to a hybrid solution is of high value at this time.
- The additional project costs and therefore slightly reduced payback associated with the hybrid approach relative to only RE or only RNG are not significant enough to outweigh the value of the hybrid option as discussed above.

The City has the ability to phase in the capital improvements based on funding and to further allow the renewable energy credit programs (both state and federal) to mature and possibly become more certain. For example, the City might proceed with the redundant digester, which provides solids stabilization redundancy as well as the ability to receive additional outside HSOWs and defer the cogeneration expansion and/or the RNG infrastructure until more clarity is reached.

For more details about the BCE, see Appendix A-4 (*Task 2.6 - Power Utility Coordination and Preliminary Economic Model Update* (Jacobs, 2023b)).

3. Anaerobic Digestion and Cogeneration Expansion

3.1 High Strength Organic Waste Receiving Facility

The WWTP is anticipated to receive FOG and food waste as the two sources of the HSOW for digestion process. The preliminary design assumes the food waste will be screened and preprocessed into a slurry by others (most likely Oregon Metro) prior to delivery at the WWTP. The HSOW receiving facility is divided into two stations, one for FOG receiving and the other for food waste slurry (FWS) receiving. This section provides a brief overview of the existing HSOW receiving facility and describes the expansion of the facility to accept additional FOG and FWS.

3.1.1 Existing Facilities

The WWTP has an existing FOG receiving station that receives up to 10,000 pounds volatile solids (lb VS)/day of FOG. The existing receiving station includes a truck unloading station, one 10,000-gallon and one 20,000-gallon storage tanks, a heating system, and feed pump. This facility was upgraded in 2021, installing a new rock trap and screening equipment.

3.1.2 New Facility – FOG Receiving Station Expansion

The FOG receiving station will continue to operate according to current protocol, but the existing storage tanks will be replaced with two new 30,000-gallon tanks to provide the storage volume needed for the project FOG quantities and provide complete storage redundancy. The facility currently receives 15,000 to 20,000 gallons of FOG per day and this is anticipated to increase up to 30,000 gallons per day. The increased tank storage will allow all of the FOG to be stored and delivered into the digester consistently for the following 24 hours. An access platform will be provided for each tank for maintenance activities.

Table 3-1 shows the preliminary design criteria for the storage tanks.

Table 3-1. Storage Tank Design Criteria

Parameter	Unit	Value
Type	-	Fiber-reinforced plastic
Quantity	each	2
Diameter	feet	14
Side water depth	feet	28
Working capacity	gallons	30,000

3.1.3 New Facility – FWS Receiving Station

A new FWS receiving station is required to accept up to 20,000 lb VS/day or approximately 18,400 gallons of FWS. This station includes the following unit processes:

- A truck unloading connection.
- An unloading pump to transfer the FWS to the storage tanks.
- Two 20,000-gallon storage tanks with individual mixing pump systems providing storage redundancy. This allows all of the feedstock to be stored and delivered to the digesters consistently for the following 24 hours.
- One feed pump to deliver the FWS to the digesters.

It is assumed that the FWS delivered to the WWTP is prescreened and processed into a slurry. Therefore, no additional screening or rock trap equipment is needed. The feedstock is also not heated in the tanks, as

the food waste may decompose in the storage tanks. A platform will be provided for each tank for maintenance activities.

Table 3-2 shows the preliminary design criteria for the unloading/transfer pump.

Table 3-2. Unloading/Transfer Pump Design Criteria

Parameter	Unit	Value
Type	-	Rotary Lobe
Quantity	each	1
Capacity, each	gpm	350
Total dynamic head	feet	45
Pumped fluid solids	%	12-15
Motor size	hp	25
Control per pump	-	Constant speed

gpm = gallons per minute; hp = horsepower.

Table 3-3 shows the preliminary design criteria for the storage tanks.

Table 3-3. Storage Tank Design Criteria

Parameter	Unit	Value
Type	-	Fiber-reinforced plastic
Quantity	each	2
Working capacity	gallons	20,000

Table 3-4 shows the preliminary design criteria for the mixing pumps.

Table 3-4. Mixing Pump Design Criteria

Parameter	Unit	Value
Type	-	Rotary Lobe
Quantity	each	2
Capacity, each	gpm	350
Total dynamic head	feet	45
Pumped fluid solids	%	12-15
Motor size	hp	25
Control per pump	-	Variable frequency drive

Table 3-5 shows the preliminary design criteria for the FWS feed pump.

Table 3-5. FWS Feed Pump Design Criteria

Parameter	Unit	Value
Type	-	Progressing Cavity
Quantity	each	1
Capacity, each	gpm	30
Total dynamic head	feet	60
Pumped fluid solids	%	12 -15
Motor size	hp	3
Control per pump	-	Variable frequency drive

3.1.4 Odor Control

This section defines and documents the basis of design for the odor control system treating foul air ventilated from the FOG and FWS receiving tanks.

At the FOG receiving tanks in 2021, two carbon canisters were replaced with high-density polyethylene (HDPE) carbon canisters with Sulfursorb carbon filter media. Using carbon canisters to treat foul air is beneficial because it does not use electricity and land use is minimized. At the FOG and FWS receiving tanks, carbon canisters will treat the foul air displaced from the filling of the receiving tanks (in-fill). The receiving tanks will be filled one at a time by the truck transfer pump. Air flow directed to the carbon canister is equal to the volume of liquid, in gallons per minute, supplied by the transfer pump converted to cubic feet per minute (cfm) of displaced air. It has been confirmed that the existing carbon canisters can support the in-fill rate for the new larger tanks being proposed for the FOG Receiving Stations.

Unlike the FOG receiving station, the two new FWS receiving tanks will have foul air treated by one HDPE canister with coconut shell carbon filter media. Coalescing filters upstream of each carbon canister are required to separate entrained droplets from the air, keeping the carbon canisters unclogged and clean. It has been noted that replacing the Sulfursorb carbon filter media has been expensive to refill. A simple portable 2S meter could analyze an air sample within the canisters at the FOG receiving station and upon review, a cheaper filter media such as coconut shell carbon could be recommended.

Another option for odor treatment would be an expansion of the existing biofilter to accommodate the additional odor loading from the FOG and FWS receiving tanks. The expansion of the biofilter would be a more significant upfront capital cost, due to an additional fan needed to provide necessary pressure to pass through the biofilter media, and challenges associated with foul air conveyance across the road to the biofilter. The biofilter media does not require frequent replacement and this type of biofilter media can usually maintain treatment of odors for up to 10 years without replacement.

Table 3-6 summarizes the carbon canister requirements based on the transfer pump utilized to fill receiving tanks at the FOG and FWS Receiving Stations.

Table 3-6. Carbon Canister Design Criteria

Location	Minimum Air Flow* (cfm)	Canister Quantity	Canister Capacity (cfm)
FOG Receiving Tanks (2)	50	2	150
FWS Receiving Tanks (2)	50	1	100

Table 3-6. Carbon Canister Design Criteria

Location	Minimum Air Flow* (cfm)	Canister Quantity	Canister Capacity (cfm)
----------	----------------------------	-------------------	----------------------------

*Canister minimum air flow is equal to the gallons per minute supplied by transfer pump converted to cubic feet per minute.

3.2 Anaerobic Digestion

This section describes the anaerobic digester system and dewatering feed tanks with heat recovery, including revisions to the existing digesters, the new digester tank design, digester mixing system, digester heating and recirculation, and digester cleaning.

3.2.1 Existing Facilities

The digestion process at the Gresham WWTP includes two 1,000,000-gallon digesters operating at mesophilic temperatures (95 to 98 degrees Fahrenheit [°F]). The digesters are operated in a series configuration, where all of the feed is directed to Digester 1 and then transferred by gravity to Digester 2. Digester 1 and Digester 2 are 80 feet in diameter and have a 27-foot sidewall depth. Digester 1 has a fixed cover, whereas Digester 2 has a floating cover, which is typically used for gas storage. Both tanks are mixed using a 20-hp linear motion mixer, each with a variable frequency drive (VFD) so that the speed can be increased or decreased depending on the feed. The digesters are heated using a pump recirculation system with a concentration tube counter flow type heat exchanger. The digested sludge is withdrawn from the digesters by pumps and sent over to dewatering.

The existing digesters and Digester Control Building were identified as having structural and nonstructural seismic deficiencies in the resilience assessment performed by Carollo Engineers as part of the *City of Gresham Wastewater Seismic Resilience Plan*, June 2019 (in the Carollo report, see Appendix E, Technical Memorandum 5 – WWTP Seismic Resilience Assessment, Sections 5.3.22 Digesters #1 and #2, and Section 5.3.23 Digester Controls Building for more information). These deficiencies will need to be investigated in more detail and evaluated to determine if the City would like the design consultant to include these seismic upgrades as part of the solids facility improvements, or if these upgrades would be implemented under a separate capital project. The costs estimated as part of the Implementation Plan (Appendix F, Technical Memorandum 6 – Implementation Plan) of the Seismic Resilience Plan have been included in the Association for the Advancement of Cost Engineering International (AACE) Class 4 (AACE, 2011) estimate that Jacobs has prepared as part of this predesign report. Costs were originally estimated in 2019 dollars and have been inflation-adjusted to bring them in line with cost assumptions used in this estimate.

3.2.2 New Facilities/Modifications to Existing Facilities

As part of this project, one new 1,000,000-gallon digester will be constructed. This digester will operate at thermophilic temperatures (130 to 135°F). The new digester tank will consist of cast-in-place or post-tensioned concrete. The digester will be equipped with a fixed carbon steel cover. The cover will include a platform for maintenance activities. The normal operating liquid level will be the same elevation as the existing digesters. Tank walls will be designed to operate with a 50°F temperature differential. Both the tank cover and tank walls will be insulated. The insulation thickness will be determined at subsequent design stages.

The geometry for the new digester can be either a pancake shape similar to existing digesters (low height to diameter ratio) or a silo type (equal height to diameter). The drawings currently show a pancake digester, which represents the worst case scenario from a site layout perspective as a pancake digester has a larger footprint. A silo type digester would reduce the footprint but would be much taller than the existing digesters. While a silo digester offers many operational benefits, there are some practical limitations that need to be considered.

The groundwater level is a constraint for how deep a digester should be constructed. It is undesirable to have the bottom of a digester extend below the groundwater level because this condition creates a heat-sink effect. This cools the digester, requiring more energy usage to keep the digester at its optimum operating temperature. A silo digester can be constructed above the groundwater level but this pushes the profile further out of the ground and makes the digester taller. The groundwater levels shown in Figure 3-1 were extrapolated from the 1997 geotechnical report (Fujitani Hilts and Associates, 1997). It is recommended to install a boring with a groundwater monitor at the location of Digester 3 to allow collection of groundwater data to help determine the optimum depth of the new digester.

Another limitation with a silo digester is that the increase in sidewall depth will require the new thickened sludge pumps to pump against a higher static head than originally designed. Preliminary calculations show that the thickened sludge pumps could potentially be capable of pumping to a water surface elevation in the new digester up to 20 feet above the water surface level in the existing digesters. Thicker sludge behaves like a Bingham plastic, making pump calculations less accurate as sludge concentrations increase. It is recommended that these preliminary pump calculation models should be calibrated against actual thickened sludge pumping operational data in the next design phase after the startup of the new rotary drum thickeners and thickened sludge pumps.

A hybrid geometry for Digester 3 is being proposed that would still offer some of the operational benefits of a silo digester, but would balance performance against these other practical limitations. The hybrid geometry would allow for a slightly steeper cone to be set just above the groundwater elevation to optimize energy usage. It would also allow the water surface elevation to be set at a level that would still be within the operating range of the new thickened sludge pumps.

The preliminary design criteria for the different digester geometries for Digester 3 are presented in Table 3-7. More information about the digester geometry is provided in Appendix H. The silo and hybrid digesters would be smaller in diameter but much taller than existing pancake digesters.

Table 3-7. Digester 3 Design Criteria

Parameter	Unit	Pancake Digester	Silo Digester	Hybrid Digester
Quantity	each	1	1	1
Inner diameter	feet	80	55	60
Sidewall height	feet	30	58	50
Side water depth	feet	27	55	47
Cone depth	feet	10	27.5	15
Height to diameter ratio	-	0.34	1	0.78
Cover type	-	Fixed carbon steel	Fixed carbon steel	Fixed carbon steel
Effective volume of digesters	million gallons	1.0	1.0	1.0
Operating temperature	°F	130–135	130–135	130–135

Figure 3-1 presents how the silo digester and hybrid digester presented in Table 3-7 would compare to the existing digesters at the WWTP.

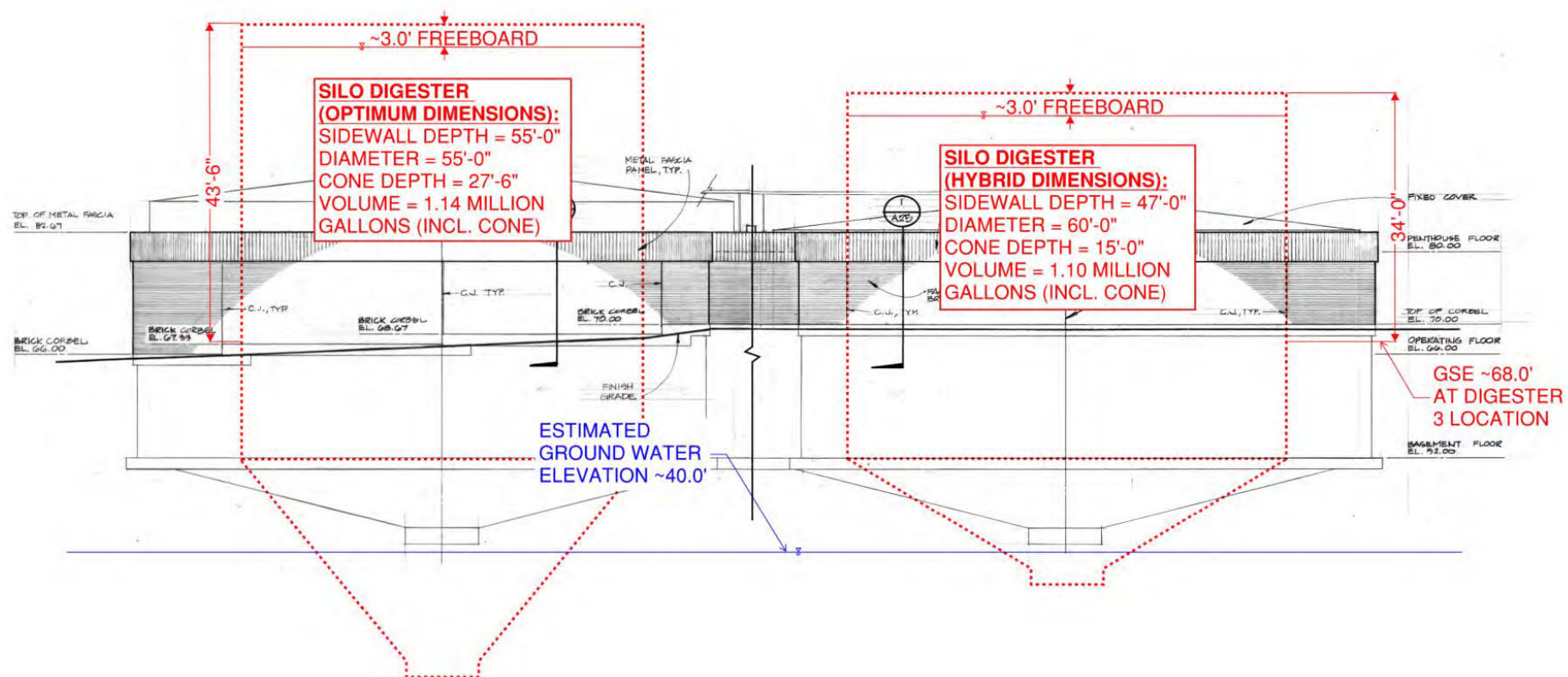


Figure 3-1. Silo Digester and Hybrid Digester Geometry Compared Against Existing Pancake Digesters

Due to the location of Digester 3, a new Digester Control Building will be constructed beside Digester 3. This building will house the digester heating and recirculation system as well as the digester withdrawal system. Construction of these new facilities will require relocation of the existing 30-inch-diameter primary effluent (PE) and 8-inch-diameter waste activated sludge (WAS) lines coming from the upper plant.

Digester gas will be withdrawn through stainless steel gas lines that transfer digester gas generated in the digester to gas storage, gas treatment, and beneficial use. The gas withdrawal connection will be located in the gas dome, above the emergency overflow line, to avoid plugging with foam.

A safety-selector valve and combination pressure/vacuum relief valves with flame arrestors will be mounted on the gas dome. Provision for additional safety-selector valve and combination pressure/vacuum relief valve will be included in the design. These valves regulate pressure in the digester to eliminate damage to the cover from digester over- and under-pressurization. The digester normal operating pressure, maximum pressure, pressure relief crack pressure, and vacuum relief crack pressure will be determined during detailed design and will likely match the existing system. A separate vacuum relief valve, with no flame trap, will be provided as a last line of defense against vacuum conditions if the combination pressure relief/vacuum valve fails. The digester cover will be equipped with a weighted hatch to provide emergency pressure relief if the pressure relief and emergency overflow mechanisms fail.

The existing two digesters will be converted to operate at thermophilic temperatures. The covers for the existing digesters will be replaced with fixed carbon steel covers and insulated. The new covers will include platforms to provide maintenance access to the mixers and other equipment. Impacts to the heating water system are further discussed in Section 3.5. The existing linear motion mixers will be retrofitted to be able to operate at the thermophilic temperatures.

A structural model was developed (see Appendix A-2) to assess the ability of the existing cast-in-place concrete digestion tanks to operate at the increased temperatures required for thermophilic digestion (130–135 °F). The analysis evaluates the capability of the reinforced concrete walls to resist the increased stresses and to stay within the stress limits required for crack-control of the concrete. The analysis determined that the existing concrete walls could accommodate these higher operating temperatures without requiring any supplemental reinforcing. It was further determined that no additional insulation would be required to limit the stress increases and mitigate long-term impacts to the existing structures.

Two new dewatering feed tanks will be constructed. The biosolids dewatering process is operated intermittently; the dewatering feed tanks will provide a storage volume to allow operational flexibility when the dewatering process is offline; it will also allow for digested sludge heat recovery prior to dewatering, which will help prevent the stored biosolids from becoming too odorous.

3.2.2.1 Digester Feed System

The WWTP typically co-thickens upper plant primary sludge and WAS, and lower plant WAS in the Solids Building and thickened sludge is fed to the existing digesters by thickened sludge pumps. Primary sludge from the lower plant and primary scum from the upper plant are sent directly to the existing digesters.

The digesters will be configured to operate in parallel regardless of the number of digesters in service, but provisions are included to allow transfer between the digesters. The sludge feeding to the digesters will be modified to include automated valves on the feed pipes that will actuate the flows to the digesters based on a feed schedule. For instance, when operating all three digesters in parallel, the actuated valve would stay open to each digester for 20 minutes (60 minutes divided by three digesters). Then the cycle would repeat. Organic waste from the HSOW facility is configured to allow for parallel feeding to the digesters. Provisions are included in the design to allow sludge to be sent to future digesters.

3.2.2.2 Digester Mixing System

The digester tank contents will be mixed to optimize volatile solids reduction and gas production. Digester 3 will be mixed using a linear motion mixing system similar to the current digesters. Linear

motion mixers use an oscillating ring-shaped hydro-disk that moves up and down through the liquid to mix the digester. Linear motion mixers use an internal cam scotch-yoke design that efficiently transfers energy from the drive motor to the liquid. Linear motion mixers have a low power demand, are easy to maintain, and have performed well for the WWTP since they were installed. The preliminary design criteria for the linear motion mixing system for Digester 3 are presented in Table 3-8. If a silo or hybrid geometry is selected, the linear motion mixers will have two or more hydro-disks with longer shafts to efficiently mix the tank.

Table 3-8. Digester 3 Linear Motion Mixing System Design Criteria

Parameter	Unit	Value
Duty units per tank	each	1
Standby units	each	0
Total solids concentration	%	2 to 4.5
Maximum motor size	hp	20
Control per pump	-	Variable frequency drive

3.2.2.3 Digester Heating and Recirculation

Digested sludge heat exchangers are required to heat sludge to thermophilic temperatures and maintain digester temperatures due to heat loss through the shell. The heat exchangers will use sludge recirculation and hot water recirculation to maintain the digester contents within the required temperature range. Solids will be withdrawn directly from the tank where sludge circulation pumps will convey the solids through a heat exchanger before the solids are returned to the digester. This configuration creates a closed recirculation loop and allows better control over digester temperature compared to heating the influent sludge directly.

No modifications or upgrades to the heat exchanger and sludge recirculation pumps are required for converting the existing digesters to thermophilic operations. The insulation for existing digesters requires no modifications for thermophilic temperatures.

The heating and recirculation loop for Digester 3 will include new sludge recirculation pumps and a spiral heat exchanger, which will be installed in a new building. Table 3-9 presents the preliminary design criteria for the digester sludge recirculation pumps. For more details about the heat loop and preliminary design criteria, see Section 3.5 of this report.

Table 3-9. Digester 3 Heating and Recirculation Design Criteria

Parameter	Unit	Value
Duty pumps	each	1
Standby pumps	each	1
Design flow per pump	gpm	360
Pump type	-	Non-clog horizontal screw centrifugal
Maximum motor size	hp	5
Pump total dynamic head	feet	15
Total solids concentration	% total solids	2 – 4.5
Motor speed	rpm	1,800

Table 3-9. Digester 3 Heating and Recirculation Design Criteria

Parameter	Unit	Value
Control per pump	-	Constant speed

3.2.2.4 Digester Withdrawal System

Digester withdrawal from the existing digesters will continue according to current operations. Sludge withdrawal from Digester 3 will be from either the liquid surface or the bottom of the cone. Surface overflow will limit foam and scum buildup in the gas dome. The sloped floor bottom (cone withdrawal) will facilitate the transfer of grit and debris through the digestion process. Withdrawing predominantly from the digester standpipe is recommended, with occasional (1 day per week) withdrawal periods from the cone. The digested sludge pumps will convey to dewatering feed tanks.

During surface overflow operation, feed sludge will displace liquid in the operating digesters. A gravity overflow line will discharge to a digester standpipe. As digested solids reaches the elevation of this pipe, it will overflow into the standpipe located adjacent to the digester. This design feature controls the digester normal liquid level. The standpipe will be a 36-inch-diameter, 316L stainless steel pipe that stands vertically adjacent to the digester. Digested solids will be pumped out of the standpipe by the digester withdrawal pumps.

A 4-inch, 316L stainless steel gas dome/standpipe equalization line will connect the headspace of the digester to the headspace of the overflow standpipe. The line will equalize pressures between the two headspaces. This pressure equalization line will be located at the same elevation as the gas withdrawal line.

During cone withdrawal operation, speed control of the digested sludge pumps will match the pumped withdrawal rate to the measured flow entering the digesters. Alternatively, the pumps could be operated in level control mode based on the level in the digester. The digester withdrawal pumps will run on variable speed drives.

Table 3-10 presents preliminary design criteria for the digested sludge pumps for Digester 3. The pumps will be progressing cavity type pumps of similar design features and flows as current pumps. Two pumps will be installed in the new control building and operated in a duty/standby configuration. Provisions will be provided in the piping for connections to future digested sludge pumps.

Table 3-10. Digester 3 Sludge Transfer Pumps Design Criteria

Parameter	Unit	Value
Duty pumps	each	1
Standby pumps	each	1
Design flow per pump	gpm	100
Pump type	-	Progressing cavity
Maximum head pressure	psi	50
Total solids concentration	%	2 to 4.5%
Motor speed	-	1,800
Maximum motor size	hp	10
Control per pump	-	Variable frequency drive

psi = pounds per square inch.

No modifications or upgrades are required for the existing digested sludge pumps for Digester 1 and Digester 2.

3.2.2.5 Emergency Overflow

Emergency overflow lines will be located on all the digesters. The invert of the emergency overflow will be located 3 feet above the invert of the normal full tank overflow line in the digesters. The location will allow free discharge of the emergency overflow such that levels and pressures in the digesters do not impact the structural integrity of the fixed cover systems.

The digester overflow will be piped through a U-shaped trap with its vertical leg taller than the maximum operating pressure of the digester. The trap will be filled with water to provide a gas seal. This feature will prevent digester gas from escaping the tank.

The emergency overflow system will be constructed from 316L stainless steel for all piping components that will regularly be exposed to digester gas. Downstream of the water trap, the remainder of the U-shaped overflow can be constructed of carbon steel. The emergency overflow will be 12 inches in diameter to prevent blockages. Emergency overflow events will flow by gravity to the lower plant aeration basin splitter box. A flushing tap will be connected to the emergency overflow to allow for high pressure cleaning. No valves will be provided on the emergency overflow line until it is routed to a safe discharge point.

Existing overflow piping for Digester 1 and Digester 2 will be reused for emergency overflows.

3.2.2.6 Nitrogen Feed Connections

Digester 3 will be equipped with a nitrogen gas connection. The nitrogen gas connection will allow staff to backflush the headspace of the tank when putting it back in service. Backflushing prevents the possibility of creating an explosive mixture of methane and oxygen during these events. The nitrogen gas system will consist of a 2-inch stainless steel pipe and appropriate valves to distribute nitrogen gas from an offloading truck to the gas headspace in the tank. The location of the nitrogen gas feed connection will be coordinated to allow easy access to a quick-fill connection.

3.2.2.7 Dewatering Feed Tanks and Heat Recovery

The dewatering feed tanks will be located to the west of the new Digester 3 Control Building and will be constructed of cast-in-place concrete walls and lids. The design criteria are summarized in Table 3-11.

Table 3-11. Dewatering Feed Tank Design Criteria and Data

Parameter	Unit	Value
Storage period required	days	1
Storage volume required (2047 average annual)	gallons	140,000
Number of dewatering feed tanks	-	2
Tank footprint (inside)	feet	23 long x 23 wide
Maximum side water depth	feet	18
Freeboard	feet	2
Maximum storage volume (per tank)	gallons	70,000
Tank mixing type	-	Pump mixing
Number of mix pumps	-	2
Mix pump motor size, each	hp	20

Table 3-11. Dewatering Feed Tank Design Criteria and Data

Parameter	Unit	Value
Control per pump	-	Constant speed

The two tanks will share a common wall, which includes a 24-inch by 24-inch opening with a gate. The tanks will be connected to the digester gas collection system and will have safety relief valves.

Typical dewatering feed tank operation will have both feed tanks in service, tandem operation. The common wall gate will be open and the sludge from the digesters will be entering one of the tanks while the dewatering feed pumps will be drawing from the other tank. By operating as such, both tanks' volume will be in use and the sludge will be circulating to avoid sludge stagnation and septic conditions. When either of the two dewatering feed tanks reach high level, then the digested sludge feed to the tanks will be stopped. Hot digested sludge from the tank that is receiving digested sludge will act as the suction for the sludge heat recovery pumps. These pumps will pump hot digested sludge through a rectangular sludge to sludge heat recovery heat exchanger. This heat exchanger will recover heat from digested sludge and transfer that heat to the thickened sludge feeding the digesters. The digested sludge outlet from the sludge heat recovery heat exchanger will be discharged to the opposite dewatering feed tank to aid in keeping the lead tank as hot as possible. Cooling digested sludge prior to dewatering is critical to avoid excessive odors at the dewatering facility. The design criteria are summarized in Table 3-12.

Table 3-12. Heat Recovery Heat Exchanger Design Criteria

Parameter	Unit	Value
Heat exchanger type	-	Rectangular channel type sludge to sludge Manufacturer DDI
Heat transfer capacity	MBH	1,500
Number heat exchangers	-	1
Hot sludge inlet temperature	°F	130
Thickened sludge inlet temperature	°F	60
Hot sludge target outlet temperature	°F	100
Hot sludge flow rate	gpm	100
Thickened sludge flow rate	gpm	30-85

MBH = 1,000 British thermal units per hour.

Alternatively, the common wall gate will be closed to take either of the tanks out of service. The other tank only will be receiving sludge from the digesters, feeding sludge to dewatering and receiving discharge sludge from the sludge heat recover heat exchanger. Under this alternate, single operation scenario, when one dewatering feed tank reaches high level, then the DS feed to that tank will be stopped.

3.3 Gas System Analysis

3.3.1 Storage

The use of a low-pressure gas holder bubble is desired to buffer fluctuation in digester gas production and use in cogeneration engines, hot water boilers, and the RNG system. The gas holder includes level and pressure instrumentation to provide a dampened signal to be used for controlling digester gas usage equipment loading. The gas storage membrane will be controlled to maintain a near constant pressure adapting to changes in gas production. This will allow the downstream gas equipment (pretreatment and gas usage equipment) to be operated at a near constant setpoint and remove the need for the equipment

to ramp up and down based on the gas production rates. The preliminary design criteria for the gas storage system are presented in Table 3-13.

Table 3-13. Gas Storage Design Criteria

Parameter	Design Criteria
Number of spheres	1
Base diameter	31 feet
Slab diameter	38 feet
Maximum gas storage volume	21,150 cubic feet
Type	Dual-membrane, low pressure
Mounting	Concrete pad
Air blowers	One duty + one standby
Controls	Packaged system with programmable logic controller, starters for air blowers
Candidate manufacturers	Based on WesTech

3.3.2 Pretreatment

Digester gas needs to be treated to protect the combustion equipment. The existing treatment system is undersized for the demands of the new expanded facility. The existing system will be replaced with a new robust system to treat all of the digester gas, including the additional gas produced from the new and converted thermophilic digesters, prior to combustion in the cogeneration engines, boiler, or processed by the RNG system. The raw gas basis of design was based on data collected through 2017; City staff is collecting updated gas constituent data from the supervisory control and data acquisition (SCADA) historian. These update data will be used to confirm that the gas cleaning system inlet conditions are properly specified for design. The preliminary design criteria for raw gas are presented in Table 3-14.

Table 3-14. Raw Gas Design Criteria

Parameter	Design Criteria
Inlet flow	370 scfm at startup average annual operation and a peak future flow of 640 scfm
Inlet temperature	95 to 125°F
Inlet pressure	4 to 12 inches water column anticipated
Moisture content	100% relative humidity
Maximum inlet H ₂ S concentration	1,500 ppm, to be confirmed
Average inlet H ₂ S concentration	700 ppm, to be confirmed
Average inlet siloxane concentration	4.8 to 5.7 milligrams per cubic meter, to be confirmed
Average inlet methane concentration	50 to 70 % v/v, to be confirmed
Average inlet carbon dioxide concentration	30 to 45 % v/v, to be confirmed

ppm = parts per million; scfm = standard cubic feet per minute; v/v = volume to volume basis.

A new digester gas treatment system will be installed to serve the new engines, boilers, and RNG system. At this time, no equipment supplier has been selected, but the included basis of design is based on conversations with Greenlane Renewables and Unison Solutions, LLC. It is recommended to complete an early procurement for the digester gas pretreatment system to confirm the system scope and allow for confirmation of interconnections between the pretreatment system and the digester gas usage equipment.

The digester gas treatment system will be sized for an initial facility annual average startup flow of 370 scfm and a peak future flow of 640 scfm through a single treatment train. The digester gas treatment system will consist of three major processes: hydrogen sulfide (H_2S) removal via media adsorption, moisture reduction, and siloxane and volatile organic compound removal via activated carbon adsorption. Condensation formed from digester gas and combustion gas streams has the potential to form sulfuric acid (H_2SO_4) when H_2S is absorbed into the condensed water. Sulfuric acid is corrosive and will cause damage to engine internals. Siloxanes form sand- and glass-like deposits after combustion, which coat pistons, valves, cylinder walls, and other internal engine components. These deposits lead to frequent engine downtime for repairs and even full rebuilds. Removing H_2S and siloxanes greatly reduces these risks. Removal of H_2S and siloxanes is required for injection of RNG into the natural gas grid by the receiving gas companies.

Warm, saturated gas is required for H_2S removal. However, relatively dry gas is required for activated carbon siloxane removal. Therefore, moisture removal will be provided between these two processes. The digester gas pretreatment outlet requirements are based on fuel specifications provided by the engine manufacturers and anticipated RNG receiving pipeline gas tariffs. Media life requirements will be based on the projected year 2047 gas flow of 640 scfm. The lead vessel for each H_2S removal and siloxane removal train will be sized to last at least 3 months before changeout. This design requirement provides a reasonable vessel size and an acceptable media bed life.

The H_2S removal train consists of two vessels in series and filled with a free-flowing pelletized ferric hydroxide media, with piping and valves arranged to allow either vessel to serve as the lead or lag vessel. Any one vessel can be shut down to remove media while the remainder of the system stays in operation. Media change out is anticipated to take 2 days (including media soaking time) and two to three technicians to complete the work. After media changeout, the vessel can be placed back into service as the lag vessel in its train. Because of the presence of H_2S and moisture, and the associated risk of formation of H_2SO_4 inside the H_2S removal system, Type 316/316L stainless steel will be used to construct the vessels, piping, valves, and heat exchangers (if applicable). Platforms, ladders, and accessories not exposed to the digester gas will be constructed from Type 304/304L stainless steel.

Activated carbon siloxane removal media requires dehumidified gas for proper operation. Digester gas leaving the H_2S removal system will be nearly saturated, so a dehumidification system between H_2S removal and siloxane removal is required. A particulate filter will be installed prior to digester gas blowers to protect the blowers. The blowers are required to provide the driving head required through the moisture removal system. Gas-chilled water heat exchangers will cool the gas from the H_2S removal system prior to moisture removal vessels, then gas-hot water heat exchangers will reheat the gas downstream of the moisture removal vessels. Gas-gas heat exchangers will use the cool, dehumidified gas downstream of the gas-chilled water heat exchangers to pre-cool the gas entering the gas-chilled water heat exchangers as well as pre-heat the gas entering the gas-hot water heat exchangers. Glycol solution will be used as the cooling fluid. Condensate will be collected in a moisture removal vessel and will be removed through an automatic drip trap. Reheating the gas will achieve the dry gas required by the siloxane removal media. The gas will also be heated after the vessels with a water to gas heat exchanger to maintain a constant temperature dry gas fuel supply of about 100°F.

The heat exchangers and moisture removal vessels will be arranged in a single train. A glycol chiller would be located on a separate skid in a nonclassified area with supply and return piping to the moisture removal skid. This does not provide redundancy of the system and could be changed during future analysis. In the event of a catastrophic failure of one of the heat exchangers, the system would not be able to operate

while the damaged unit is repaired or replaced. The glycol solution will require treatment with corrosion inhibitors.

While the H₂S removal vessels will eliminate most of the H₂S from the digester gas, there will be trace amounts of H₂S present that could increase to 10 parts per million by volume (maximum) as the H₂S removal media reaches saturation. Because of the risk associated with sulfuric acid forming inside the moisture removal system and the potential for condensation forming inside vessels and piping during winter months, Type 316/316L stainless steel will be used to construct all vessels, digester gas and condensate piping, digester gas and condensate valves, and heat exchangers. Glycol piping and valves will follow the program standard for chilled water. Platforms, ladders, and accessories not exposed to the digester gas will be constructed from Type 304/304L.

The siloxane and volatile organic carbon removal vessels will receive warm dehumidified gas from the dehumidification system. The siloxane removal vessels will be arranged in a single train, with two vessels in series. The piping and valves will be arranged to allow any vessel to serve as the lead or lag vessel. Any vessel can be removed from service and the media changed while the system remains operational. Media change out is anticipated to take 4 to 6 hours.

The final particulate filters will be arranged as a single unit downstream of the siloxane removal vessels. A single unit does not provide redundancy and will need to be taken offline for cleaning and changing of equipment and would result in no final particulate filtration during these time periods, but this is expected to be for a short timeframe only.

A final reheat heat exchanger will be arranged as a single unit downstream of the final particulate filter to reheat the gas using hot water if the temperature leaving the particulate filter drops below 80°F. The heat exchanger will be sized for the full facility gas flow.

Because dehumidification occurs upstream of siloxane removal, the risk of sulfuric acid forming inside the siloxane removal system is reduced. However, condensation is still possible within the siloxane removal system, so the siloxane removal vessels, particulate filters, and reheat heat exchangers will be constructed from Type 304/304L stainless steel to mitigate potential corrosion concerns. To provide consistency with piping and valves throughout gas treatment, and to prevent the possible installation of Type 304/304L stainless steel piping and valves where Type 316/316L stainless steel is required, the siloxane removal and particulate filter system piping and valves will be constructed from Type 316/316L stainless steel. Platforms, ladders, and accessories not exposed to digester gas will be constructed from Type 304/304L stainless steel.

Following pretreatment, the digester gas could be used by the upgraded cogeneration system to produce heat and power, combusted in the boilers to provide heat, or further cleaned in the RNG system for injection into the natural gas grid. Further information is provided for the gas usage options in other sections of this report. The preliminary design criteria for the pretreatment system are presented in Table 3-15.

Table 3-15. Pretreatment System Design Criteria

Parameter	Design Criteria
Capacity	Sized for an initial facility annual average startup flow of 370 scfm and a peak future flow of 640 scfm
H ₂ S removal vessels	Two 10-foot-diameter free standing media vessels, operated in lead/lag configuration
H ₂ S removal media	Iron sponge or SulfaTreat™
Maximum hydrogen sulfide	<10 parts per million by volume
H ₂ S removal materials of construction	Type 316/316L stainless steel

Table 3-15. Pretreatment System Design Criteria

Parameter	Design Criteria
H ₂ S electrical classification	Class I, Division 1
Gas boosters	One duty and one-standby
Gas booster type	Rotary lobe positive displacement blower
Gas booster electrical classification	Class I, Division 1
Moisture removal	Dual-core heat exchanger with chilled water and gas reheat
Moisture removal system electrical classification	Class I, Division 1
Chiller system	Packaged glycol system with capacity of 25 to 100% of rated capacity, one glycol circulation pump
Chiller system electrical classification	Unclassified
Siloxane removal vessels	Two 6-foot-diameter free standing media vessels, operated in lead/lag configuration
Siloxane removal media	Activated carbon, to be confirmed
Maximum siloxane	<100 parts per billion by volume
Siloxane removal materials of construction	Type 304/304L stainless steel vessels and 316/316L valves and piping
Siloxane electrical classification	Class I, Division 1
Final particulate filter	Downstream of siloxane vessels to polish gas for 99% removal of 3 micron and larger particulate and liquid droplets
Controls	Packaged system with programmable logic controller, adjustable speed drives for gas boosters
Control panel electrical classification	Unclassified
Gas pretreatment system discharge pressure	6 pounds per square inch gauge
Discharge temperature	80°F
Dew Point temperature	40°F
Relative humidity	~25%
Candidate manufacturers	Unison Solutions, others to be determined

3.3.3 Renewable Natural Gas Treatment

Cleaning digester gas to pipeline quality for injection into the grid requires further treatment of the pretreated digester gas to remove any residual oil, moisture, and the carbon dioxide (CO₂) content. Also required is additional gas compression, gas constituent analyzer, carbon polishing, controls and an enclosure for outdoor installation.

Based on discussions during the predesign evaluation services, there is a desire for the RNG system to be capable of processing the gas remaining after the cogeneration engines and boilers are fueled or processing all of the digester gas produced in the digesters. Operation in this manner results in a wide range of feed gas flow ranges for the equipment to accommodate. Table 3-16 indicates the anticipated minimum RNG system feed flow, annual average feed and peak feed flows.

Table 3-16. RNG System Anticipated Flow Capacity

Scenario	Minimum RNG System Feed (scfm)	Annual Average RNG System Feed (scfm)	Peak RNG System Feed (scfm)
Facility startup (2027)	63	370	445
Facility buildout (2047)	230	560	640

It is proposed to utilize a 3-stage membrane system configured into two treatment trains to provide the necessary turndown for the low flow scenario and also be able to process the peak RNG flow. The information included here is based on Unison Solutions, LLC. Conversations have also taken place with Greenlane Renewables based on a pressure swing adsorption system (PSA). The PSA system would struggle to meet the low flow scenario and is less expandable than the membrane system; therefore, the information contained herein is based on the membrane system.

The 3-stage membrane system operates with all of the gas flow feeding the 1st stage. The 2nd stage is fed with methane rich gas from the 1st stage and the 3rd stage is fed with CO₂ rich gas from the 1st stage. The 2nd stage produces the final gas and feeds product gas compression equipment. The 2nd and 3rd stage has a recycle stream containing methane that is returned to feed gas compression. The 3rd stage also produces a waste stream that is primarily CO₂.

Methane recovery from a 3-stage membrane system would be expected to be greater than 99 percent and the uptime of the system is anticipated to be greater than 95 percent, with downtime due to anticipated and unanticipated maintenance needs. Preliminary design criteria for the RNG treatment system are presented in Table 3-17.

Table 3-17. Renewable Natural Gas Treatment System Design Criteria

Parameter	Design Criteria
Capacity	Sized for an initial facility minimum flow of 63 scfm and a peak future flow of 640 scfm
Treatment technology	Membrane separation
Number of stages	3-stage
Discharge pressure	190 pounds per square inch gauge*
Moisture removal	Yes
Oil removal	Yes
Compression system	Yes
Controls	Packaged system with programmable logic controller, adjustable speed drives for gas boosters
Gas analyzer	Yes
Carbon polishing system	Yes
System enclosure	Includes an electrically non-classified electrical room, moisture removal system, compression system and CO ₂ removal system

Table 3-17. Renewable Natural Gas Treatment System Design Criteria

Parameter	Design Criteria
Candidate manufacturers	Unison Solutions, others to be determined

* To be confirmed with receiving gas pipeline company (Northwest Natural Gas).

3.3.4 Waste Gas Burner

Currently, the facility has two waste gas burners onsite. A candle stick flare was installed around 1987 and is located next to the HSOW receiving station in a very congested area and near the digesters. A second waste gas burner was installed in 2019 and located between the clarifier and Digester 1. The older waste gas burner has exceeded its useful life and will be demolished as part of this project. The newer flare is a candlestick flare and sized for 1,040 scfm, significantly more than the anticipated future digester gas production. The waste gas burner is equipped with an automatic re-ignition system specifically designed for burning low pressure wastewater sludge gas. If the flare is to combust high-Btu gas, gas that has been upgraded to pipeline quality, the existing flare would require modification. It is anticipated that the stack would need to be changed to 310SS and change out componentry in the shroud area to handle the higher Btu content gas. In addition, the pressure of the RNG quality gas would need to be reduced to no greater than 1 psi, from the receiving pipeline operating pressure.

To avoid modifications to the existing flare, the boilers could be used to combust upgraded gas rather than the flare. This would require the boilers to be operational for RNG system start up and when the RNG system is producing off specification gas. If all of the facility heat is being met by the cogeneration system, the boiler heat would all be wasted. The heating water loop would need to be equipped with a 3W heat exchanger to cool the primary heating water loop, similar to the current water loop. Determination of this decision should be completed prior initiating the final facility design.

Table 3-18 presents the design criteria for the existing waste gas burner.

Table 3-18. Existing Waste Gas Burner Design Criteria

Parameter	Design Criteria
Type of flare	Candlestick
Vertical flame trap assembly	10-inch
Electric drip trap	6-quart
Sediment trap	8-inch
Emergency vent & manhole cover	30-inch
Waste gas burner	10-inch
Flare capacity	1,040 scfm
Maximum pressure drop	0.5 inch water column at rated capacity
Digester gas connection	10-inch, 125 lb ANSI flange
Height of burner	14.22 feet above grade
Control panel	Remote mounted unit located at least 15 feet from the waste gas burner
Feed gas	Raw digester gas
Pilot fuel	Natural gas
Pilot fuel feed pressure	4 to 27 inches water column

Table 3-18. Existing Waste Gas Burner Design Criteria

Parameter	Design Criteria
Manufacturer	Shand & Jurs (current manufacturer)

3.4 Cogeneration

3.4.1 Existing Facilities

The WWTP currently produces heat and electricity onsite using a 395-kilowatt (kW) cogeneration engine installed in 2005 and a 403-kW cogeneration engine installed in 2015. A standby boiler provides backup heat and a 360-kW photovoltaic array (AC side of inverters) provides additional power generation. The cogeneration engines on average consume slightly less digester gas than is produced by the digesters (approximately 79 percent – see Figure 3-2), with the remainder being flared. The boiler is dual fuel and can use either digester gas or natural gas. The plant experienced a significant outage of the cogeneration system, FOG receiving station, and secondary digester for an improvement project in October and November of 2022. Therefore, all digester gas produced was flared during that time period.

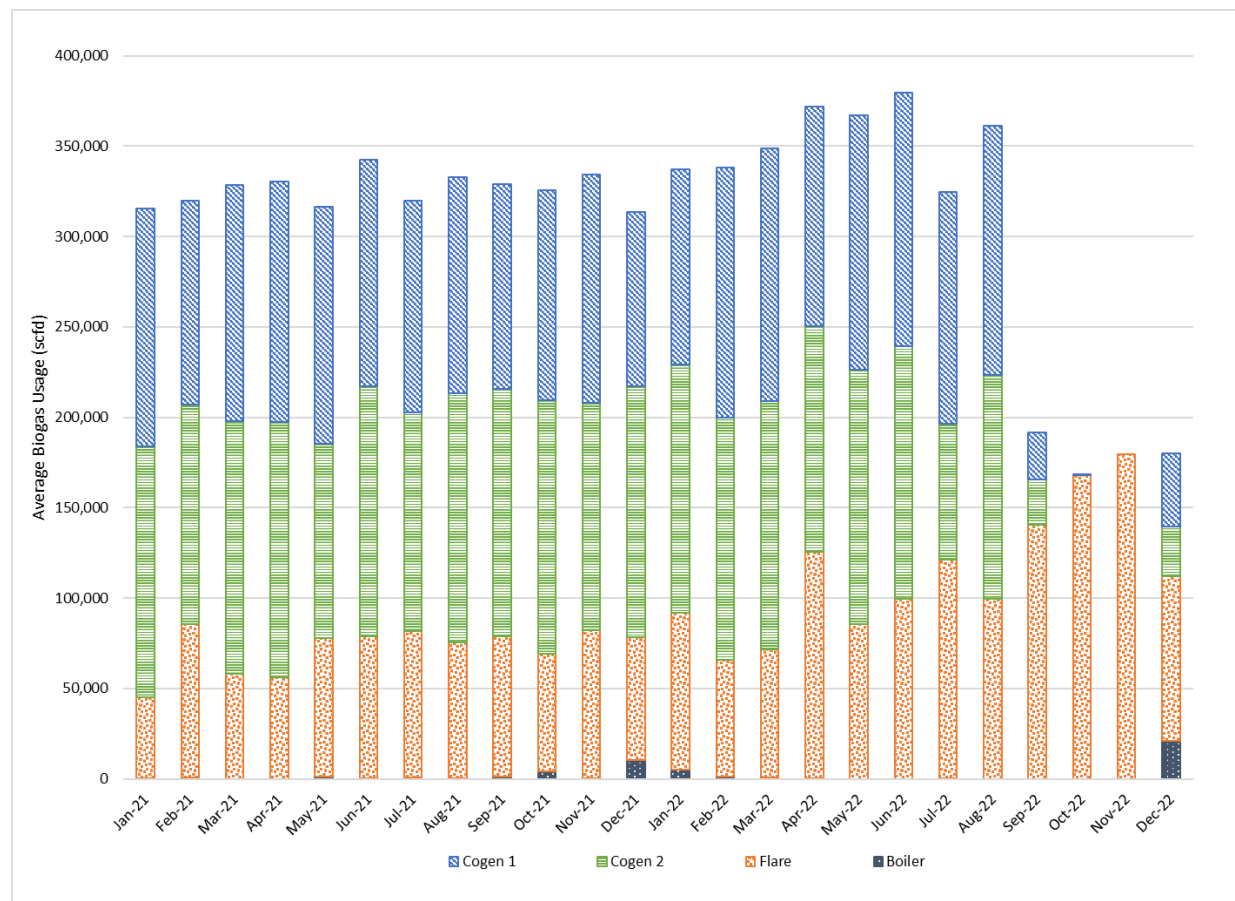


Figure 3-2. Digester Gas Monthly Production and Usage 2021–2022

Source: Plant SCADA Data Received December 2022

The existing cogeneration system is located in the existing digester complex in a common room at grade with a standby boiler in the basement below. Currently, heat is recovered from the cogeneration units and used to heat the two anaerobic digesters and the Administration Building, Solids Building, and Lower Headworks Building and for supplemental heat in the Thickener Building. The cogeneration system

provides adequate heat for the plant (see Figure 3-3) with the standby boiler only fired (manually) if necessary due to engine maintenance activities, such as during the October and November 2022 outage for an improvement project.

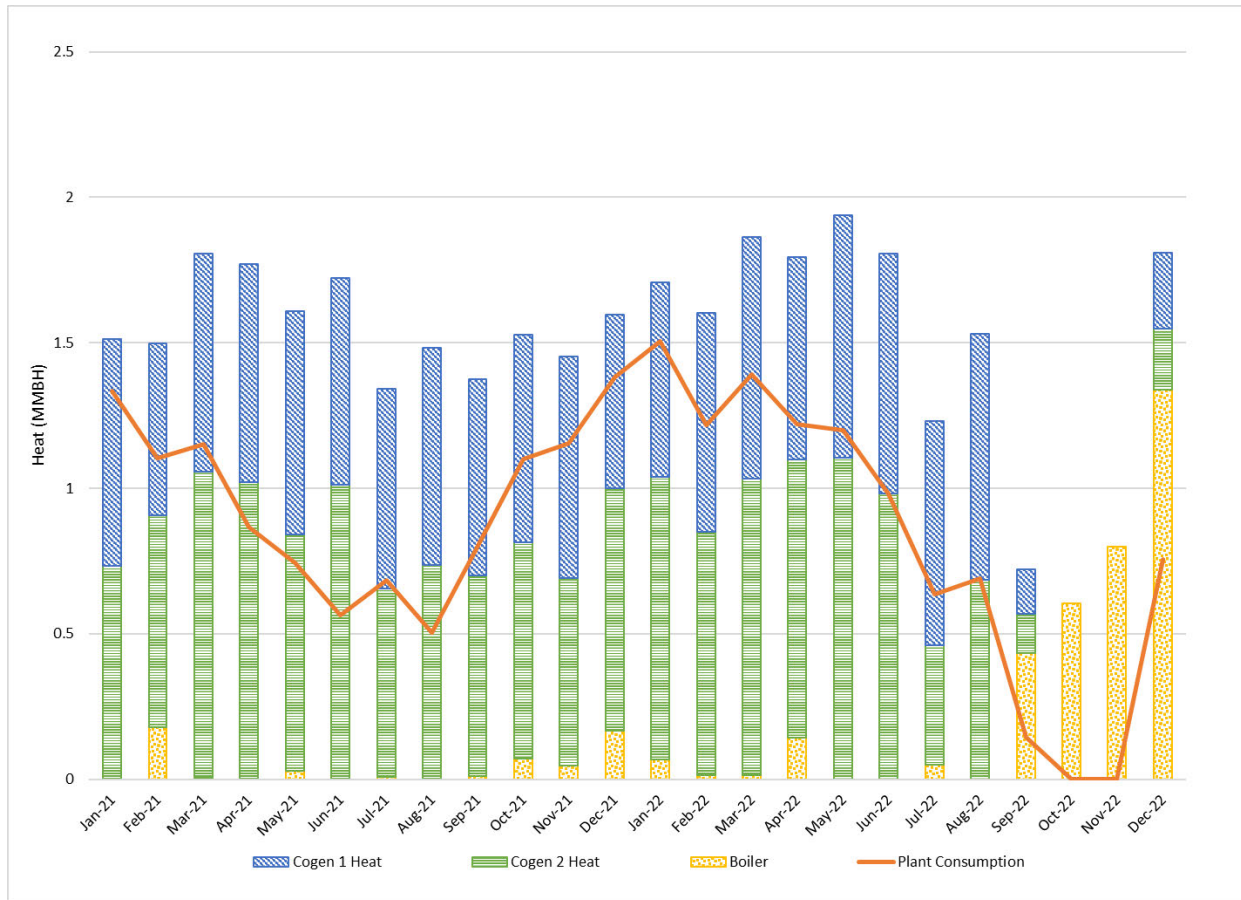


Figure 3-3. Heat Production versus Heat Consumption 2021-2022

Source: Plant SCADA Data Received December 2022

The cogeneration system generally produces enough electricity to power the plant, with the photovoltaic array generally filling in any gaps in production versus consumption. On average, the cogeneration system produces approximately 99 percent of the plant power consumption, with the photovoltaic array generating an average of 8 percent of the plant power consumption. The result is a net zero plant with some power being fed back into the grid. See Figure 3-4. The cogeneration system outage in October and November of 2022 can clearly be seen in the figure below. In addition, the solar power inverter failed in the spring of 2022, so the solar power system was not able to provide power until that was repaired recently.

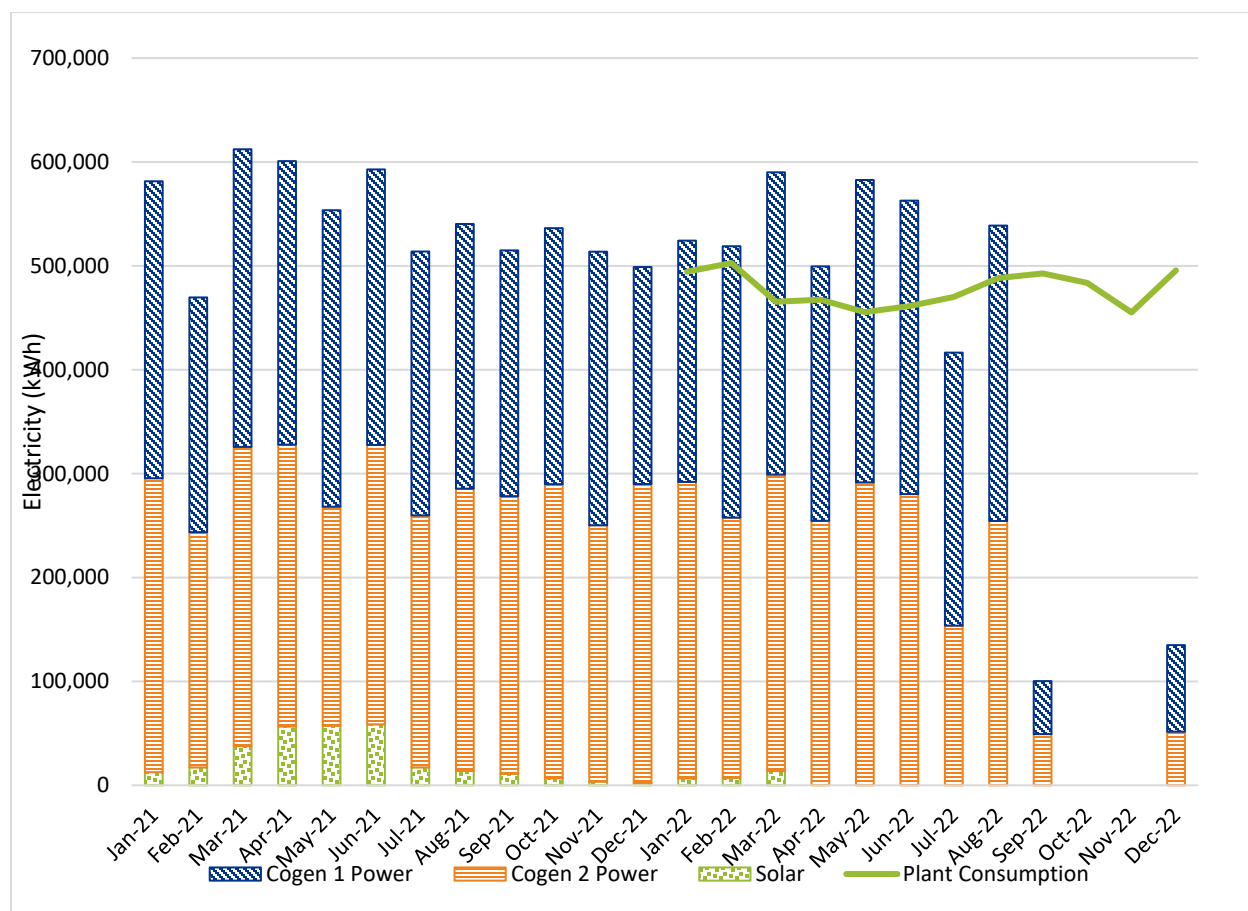


Figure 3-4. Electricity Production versus Electricity Consumption 2021–2022

Source: Plant SCADA Data Received December 2022

Note that in the figure above, detailed SCADA data for the plant power consumption were only made available for 2022, while power production data were available for both years. The data show a net-zero trend similar to that shown in the 2017 Master Plan.

Plant power and heating requirements are expected to increase with digester and other upgrades. Therefore, the existing cogeneration system will be replaced to accommodate these additional demands. To accommodate larger engines and construction phasing, the new system will reside in a new facility and the existing system will be decommissioned.

3.4.2 New Facilities

The new cogeneration system will be located in a new facility west of the existing digester facility and adjacent to the new digester gas treatment system described in Section 3.3. The facility will house two 600 kW nominal cogeneration engines. Table 3-19 presents preliminary design criteria for the cogeneration engines.

Table 3-19. Cogeneration Engines Design Criteria

Parameter	Unit	Value
Number of engines	each	2
Type	-	Ultra-lean burn turbocharged spark-ignition internal combustion engine
Power output ^a	kW (each)	600

Table 3-19. Cogeneration Engines Design Criteria

Parameter	Unit	Value
Generator voltage	volts/phases	480/3
Heat availability ^b	Btu/hr (each)	2,124,000 ±8%
Fuel consumption ^c	scfm (each)	144 ±8%
Electrical efficiency ^a	%	41.2
Heat recovery efficiency ^b	%	42.7
Total efficiency ^d	%	83.9
Backup heat rejection	-	Radiators

^aEngine manufacturers vary some in power output/electrical efficiency. Values based on Caterpillar CG132-12 at full load.

^bEngine manufacturers vary some in heat availability/efficiency. Values based on Caterpillar CG132-12 at full load and recovering jacket water heat and exhaust heat with exhaust heat exchanger gas outlet temperature of 356°F.

^cFull-load fuel consumption based on assumed digester gas LHV of 575 Btu/scf and Caterpillar CG132-12 data sheet stated tolerances.

^dSummation based on Caterpillar CG132-12 values and full-load operation.

Btu/hr = British thermal units per hour; Btu/scf = British thermal units per standard cubic feet.

The plant heating and power demands are projected to increase with the proposed digestion upgrades. Based on the study, *Gresham Wastewater Treatment Resilient Microgrid* (Energy Trust of Oregon, 2022), the current plant power demand ranges from a low of approximately 400 kW to a high of approximately 1,100 kW. It is assumed that the power profile will be similar with the overall increased power demand (e.g., both the minimum and maximum will increase by approximately the same proportion). It is not ideal to run an ultra-lean burn gas engine lower than approximately 55 percent load (or approximately 75 percent load with selective catalytic reduction) for long periods of time, as this tends to increase exhaust gas temperatures to the point that the exhaust treatment equipment could be damaged. If the minimum plant load remained at 400 kW, that would represent a minimum load of 66 percent for one 600-kW engine, which should be acceptable. A more detailed analysis comparing concurrent digester gas production and plant power demand should be performed, but it may be beneficial to stage the addition of the cogeneration units to provide optimum flexibility by retaining the newer of the existing engines. The engine rooms are laid out with two 600-kW cogeneration units shown per the master plan, but an 800 kW unit would fit in the same space. The space within the electrical room will need to be revisited if it is desired to have provisions for larger 800-kW units in the future. This would potentially allow one 800-kW unit and one 403-kW unit for a total of 1,203 kW while providing more ability to cover the low range of the current plant power demand without excessive power export to the utility.

The cogeneration facility will consist of an engine room, an electrical room, and a small control room. The new boilers and heating water main loop pumps will be located in the new Digester Control Building, as described in Section 3.5. The heating water loop will connect to the engine heat recovery heat exchangers and pumps inside the engine room. The heat recovery heat exchangers will be plate-and-frame type to allow for easy expansion if required to increase heat recovery. The heat recovery pumps will be end-suction centrifugal type. The exhaust heat recovery heat exchanger and silencer are planned to be located inside the engine room, although a separate silencer may be provided on the roof, depending on noise requirements and the selected cogeneration engine system. The heat recovery piping and heat exchanger arrangement vary from manufacturer to manufacturer, so a second heat recovery pump per engine may be required for exhaust heat recovery.

Waste heat not recovered by the heating water system will be automatically rejected to radiators located adjacent to, or on the roof of, the cogeneration facility. The low temperature requirements for the second stage intercoolers means that this heat is always rejected. The radiators for each engine will either be provided with separate circuits for low-temperature heat rejection (second-stage intercooler) and high temperature heat rejection (engine jacket, oil cooler, first-stage intercooler), or two separate radiators for each engine may be provided for the low and high temperature cooling circuits. This will be determined based on the selected engine. Each engine will have a dedicated radiator system, but it may be possible to have cross-over valves between the two radiator systems for redundancy. This will be determined once an engine is selected. It is anticipated that the heat rejection loop for each engine will be filled with a 50:50 glycol/water mixture to prevent freezing in the winter when an engine is offline. The radiator fans will be VFD-driven and will adjust speed based on the cooling water supply temperature to the engines.

The engines will meet federal emissions requirements for biogas-fueled engines through use of oxidation catalysts to oxidize carbon monoxide, unburned hydrocarbons, and volatile organic compounds. It is not anticipated that further exhaust treatment (e.g., selective catalytic reduction system for further NO_x reduction) will be required based on current regulations.

Fresh and waste oil storage tanks will be located adjacent to the cogeneration facility. Both tanks will be UL 142 listed with double-wall construction and all the required appurtenances. Depending on the selected engine, the fresh oil local to each engine will be incorporated into the cogeneration skid, or a smaller locally-mounted fresh oil makeup tank will be located next to each engine. Gear-type oil pumps will transfer fresh oil from the fresh oil storage tank to the engine makeup tank(s). Engine-mounted pumps will transfer waste oil from the engine sumps to the waste oil storage tank during an oil change. Gear-type oil pumps will transfer waste oil from the waste oil storage tank to a tanker for disposal.

The cogeneration facility will include an electrical room adjacent to the engine room incorporating the motor control center (MCC), panelboards, and 480 volt (V)/120 V transformers to power smaller loads (programmable logic controllers [PLCs], lighting, receptacles, etc.). The 12.47-kilovolt (kV) pad-mounted transformers and synchronizing switchgear will be located adjacent to the cogeneration facility. Depending on the final location of the facility, the facility footprint may be increased to include the synchronizing switchgear inside the electrical room. The engine controllers will be located in the engine rooms as these will be connected to the engine by manufacturer-supplied wiring harnesses. Ancillary systems related to the engines will be controlled by PLC(s) located in the electrical room.

An operations room will be provided to allow operators to monitor and operate the engine systems. A human-machine interface will be provided to allow operators to connect to the engine controllers and ancillary cogeneration systems. A separate human-machine interface will be connected to the plant supervisory control and data acquisition system.

3.5 Hot Water Loop System

Heating water for digesters as well as for building heat will be provided by a common heating water system. The heating water schematic is presented in Drawings 01-G-0053 and 01-G-0054. Heating loads include the digesters, FOG heating, biogas treatment, existing digester facility heating, ventilation, and air conditioning (HVAC), Administration Building HVAC, Solids Building HVAC, headworks HVAC, Maintenance Building HVAC, and the new proposed digester facility HVAC.

Heat is recovered by the cogeneration engines and two duty boilers with a standby boiler. The boilers will be provided with separate gas trains to allow them to be fired from treated digester gas or natural gas.

Two primary loop pumps will be provided in a duty/standby arrangement and will be located in the new Digester Control Building. These pumps will be VFD driven so flow can be adjusted to the actual heat load for energy savings over a constant flow primary loop. The secondary loop pumps will be constant speed with three-way valves adjusting the heat input to the secondary loops. No standby pumps are provided for secondary loops. The boiler pumps will operate in a similar fashion but providing heat input to the primary loop. The cogeneration engine heat recovery pumps will be VFD-driven to maximize the available heat

input to the primary loop. The primary and secondary loops will be designed for a 20°F temperature change.

The preliminary heat loads and inputs are summarized in Tables 3-20 and 3-21.

Table 3-20. Preliminary Heat Loads

Name	Load (MBH)	Remarks
Digesters	5,325	Thermophilic (130°F)
FOG heating	520	30,000 gallons per day
Digester gas pretreatment	220	
New Digester Control Building HVAC	255	Estimate to be refined during detailed design
New Cogeneration Building HVAC	150	
Existing Digester Control Building HVAC	220	
Solids Building HVAC	425	
Headworks HVAC	750	
Administration/Lab Building HVAC	300	
Maintenance Building HVAC	190	
Total	8,355	

MBH = 1,000 British thermal units per hour.

Table 3-21. Preliminary Heat Inputs

Name	Input (MBH)	Remarks
Cogeneration Engine 1	2,124	New 600 kW engine
Cogeneration Engine 2	2,124	New 600 kW engine
Boiler 1	5,230	Existing boiler
Boiler 2	3,350	New boiler
Boiler 3	3,350	New boiler
Total	10,948	Not including existing boiler (standby boiler)

3.5.1 Heat Exchangers

Digested sludge heat exchangers are required to heat sludge to thermophilic temperatures and maintain digester temperatures due to heat loss through the shell. The heat exchangers will use sludge recirculation and hot water recirculation to maintain the digester contents within a temperature range.

To size the sludge heat exchangers and hot water loop system, two design conditions were considered: 2047 average day flow with one digester out of service and 2047 maximum 15 day-flow with all digesters in service (two existing and one new digester in service). The 2047 average day flow with one digester out of service resulted in the largest heat demand per heat exchanger; thus, it was used for the design criteria.

The existing sludge tubes in tube heat exchangers for Digesters 1 and 2 are anticipated to remain in service and operate at thermophilic temperatures. The existing sludge heat exchangers are adequately sized to provide the required heat transfer to Digesters 1 and 2 at thermophilic temperatures. Heat exchanger design criteria for Digesters 1 and 2 are presented in Table 3-22.

Table 3-22. Digesters 1 and 2 Heat Exchanger Design Criteria

Parameter	Unit	Value
Duty heat exchangers (existing)	each	2
Standby heat exchangers	each	0
Hot fluid	-	Water
Hot fluid temperature – influent	°F	180
Hot Fluid temperature – effluent	°F	160
Hot fluid flow	gpm	270
Number of tubes (passes)	#	12
Cold fluid	% total solids	Digested solids at 2 to 4.5% total solids
Cold fluid temperature – influent	°F	130
Cold fluid Temperature – effluent	°F	140
Cold fluid flow	gpm	360
Heat Exchanger Surface Area	Square feet	196
Maximum overall heat transfer coefficient	Btu/hr-sf-°F	250
Heat transfer capacity	MMBtu/hr- HEX	2.7
Heat exchanger type	-	Tube in Tube

Btu/hr-sf-°F = British thermal units per hour-square foot-degrees Fahrenheit; MMBtu/hr-HEX = million British thermal units per hour per heat exchanger; TBD = to be determined.

A new heat exchanger for Digester 3 will be installed in the Digester 3 Control Building. The design criteria for the new Digester 3 heat exchanger are presented in Table 3-23.

Table 3-23. Digester 3 Heat Exchanger Design Criteria

Parameter	Unit	Value
Duty heat exchangers	each	1
Standby heat exchangers	each	0
Hot fluid	-	Water
Hot fluid temperature – influent	°F	180
Hot Fluid temperature – effluent	°F	160
Hot fluid flow	gpm	270
Hot fluid maximum pressure drop	-	TBD

Table 3-23. Digester 3 Heat Exchanger Design Criteria

Parameter	Unit	Value
Cold fluid	% TS	Digested solids at 2 to 4.5% TS
Cold fluid temperature – influent	°F	130
Cold fluid temperature – effluent	°F	140
Cold fluid flow	gpm	360
Cold fluid maximum pressure drop	-	TBD
Maximum overall heat transfer coefficient	Btu/hr-sf-°F	250
Heat transfer capacity	MMBtu/hr-HEX	2.7
Heat exchanger type	-	Spiral

Btu/hr-sf-°F = British thermal units per hour-square foot-degrees Fahrenheit; MMBtu/hr-HEX = million British thermal units per hour per heat exchanger; TBD = to be determined.

A spiral heat exchanger is recommended for this application. A spiral heat exchanger consists of two rectangular channels wrapped helically around a split mandrel to create two curved channels for fluid flow. Each channel is usually constructed using two sheets of metal spaced by welded studs. The spiral assembly is enclosed by a cylindrical shell and two circular end covers are installed to seal the flow channels and provide distinct flow paths for each fluid. Heat exchange occurs across the metal coil.

Spiral heat exchangers have a small footprint and are relatively easy to maintain. The spiral design creates a self-cleaning process, where any blockages in the channel create a localized increase in fluid velocity. The velocity increase exerts a drag force on the fouled surface, which helps to dislodge and clear the blockage. Also, the heat transfer surface is a thick metal plate, so leakage rarely occurs between channels. Because of the minimal maintenance requirements, spiral heat exchangers are the most commonly used sludge-to-water heat exchangers in digester heat recovery systems throughout the world. The spiral design also has a high surface area-to-volume ratio, which results in a smaller footprint and higher heat transfer rate than a tube-in-tube or shell-and-tube configuration. The primary disadvantage of a spiral configuration is that the end cover for the water channel cannot be opened for maintenance access. However, maintenance on the water channel is rarely needed.

The following limitations on the heat exchanger design is recommended:

- Minimum sludge viscosity shall be 0.004 pound per foot per second.
- Sludge channels shall have no single dimension less than 1 inch.
- Sludge openings shall have no pins or other restrictions.
- Heat exchangers shall be designed for a maximum working pressure of 50 pounds per square inch gauge and temperature of 200°F.
- The minimum fouling factor assumed for all heat transfer calculations shall be 500 hour-square foot-°F/MMBtu.
- Material of construction shall be carbon steel or stainless steel.
- Maximum sludge temperature increase shall not exceed 10°F.
- Sludge channel velocities within the heat exchanger shall be between 3.0 and 7.0 feet per second.
- Heat exchangers shall be manufactured to American Society of Mechanical Engineers standards.

3.5.1.1 Heating Water Heat Exchangers

Heating water heat exchangers used to transfer heat from water to water or water to glycol solutions will be plate and frame type heat exchangers to allow for additional plates to be installed if additional heat transfer requirements are needed in the future.

Cogeneration engine heat recovery heat exchangers will be installed in the new cogeneration facility, recovering heat from the cogeneration engines and transferring the heat to the heating water loop. Design criteria for the cogeneration engine heat recovery heat exchangers are presented in Table 3-24.

Table 3-24. Cogeneration Engine Heat Recovery Heat Exchanger Design Criteria

Parameter	Unit	Value
Duty heat exchangers	each	2
Standby heat exchangers	each	0
Hot fluid	-	Glycol Solution
Hot fluid temperature – influent	°F	210
Hot fluid temperature – effluent	°F	155
Hot fluid flow	gpm	TBD
Hot fluid maximum pressure drop	-	TBD
Cold fluid	-	Water
Cold fluid temperature – influent	°F	165
Cold fluid temperature – effluent	°F	185
Cold fluid flow	gpm	215
Cold fluid maximum pressure drop	-	TBD
Maximum overall heat transfer coefficient	Btu/hr-sf-°F	500
Heat transfer capacity	MMBtu/hr-HEX	2.124
Heat exchanger type	-	Plate and Frame

Btu/hr-sf-°F = British thermal units per hour-square foot-degrees Fahrenheit; MMBtu/hr-HEX = million British thermal units per hour per heat exchanger; TBD = to be determined.

A heating water loop dump heat exchanger will be provided and located in the new cogeneration facility to be used when commissioning renewable natural gas treatment system. In this scenario, the renewable natural gas treatment system will be producing gas prior to approval for injection into the pipeline. This excess gas must be sent somewhere and in this scenario the boilers would burn this excess gas, causing the temperature in primary heating water loop to rise above normal temperatures. The dump heat exchanger would be utilized to cool the primary heating water loop back down to normal temperatures. Non-potable plant effluent water would be used for the cooling liquid and would be wasted to plant effluent. Design criteria for the dump heat exchanger are presented in Table 3-25.

Table 3-25. Heating Water Loop Dump Heat Exchanger Design Criteria

Parameter	Unit	Value
Duty heat exchangers	each	1
Standby heat exchangers	each	0

Table 3-25. Heating Water Loop Dump Heat Exchanger Design Criteria

Parameter	Unit	Value
Hot fluid	-	Water
Hot fluid temperature – influent	°F	192
Hot fluid temperature – effluent	°F	108
Hot fluid flow	gpm	83
Hot fluid maximum pressure drop	-	TBD
Cold fluid	-	Non-potable water (plant effluent)
Cold fluid temperature – influent	°F	60
Cold fluid temperature – effluent	°F	TBD
Cold fluid flow	gpm	TBD
Cold fluid maximum pressure drop	-	TBD
Maximum overall heat transfer coefficient	Btu/hr-sf-°F	500
Heat transfer capacity	MMBtu/hr-HEX	3.350
Heat exchanger type	-	Plate and frame

Btu/hr-sf-°F = British thermal units per hour-square foot-degrees Fahrenheit; MMBtu/hr-HEX = million British thermal units per hour per heat exchanger; TBD = to be determined.

3.5.2 Pumping

The primary and secondary loop pumps will be designed for flow rates corresponding to the heat loads and design loop temperature change of 20°F for process loads and 30°F for new HVAC loads. The existing HVAC secondary loop flow rate and design temperature change will remain unchanged to avoid modifications in other facilities and existing yard piping. Piping layouts and hydraulic calculations will be performed during detailed design to determine ultimate pump head and horsepower requirements.

Two primary loop pumps will be provided in a duty/standby arrangement. These pumps will be VFD-driven so flow can be adjusted to the actual heat load for energy savings over a constant flow primary loop. The secondary loop pumps will be constant speed with three-way valves adjusting the heat input to the secondary loops. No standby pumps are provided for secondary loops. The boiler pumps will operate in a similar fashion but providing heat input to the primary loop. The cogeneration engine heat recovery pumps will be VFD-driven to maximize the available heat input to the primary loop. Heating water piping configuration will be a two pipe system with a supply and a parallel return line.

Preliminary pump sizing is summarized in Table 3-26.

Table 3-26. Preliminary Pump Sizing

Name	Flow Rate (gallons per minute)	Remarks
Heating water primary loop pumps	1,000	Duty/standby.
Digester 1 Heating Water Pump	270	Replace existing pump.
Digester 2 Heating Water Pump	270	Replace existing pump.

Table 3-26. Preliminary Pump Sizing

Name	Flow Rate (gallons per minute)	Remarks
Digester 3 Heating Water Pump	270	
Existing plant HVAC heating water pumps	285	Existing duty/standby pumps serving existing plant HVAC loads, Digester Control Building, Solids Building, Headworks, Admin/Lab, and Maintenance Building.
New Digester Control Building heating water pump	17	Estimate to be refined during detailed design.
Gas Treatment heating water pump	22	
New Cogeneration Building HVAC heating water pump	10	
Boiler 1 (existing) recirculation pump	525	Replace existing pump.
Boiler 2 recirculation pump	335	May change if boiler size is increased.
Boiler 3 recirculation pump	335	May change if boiler size is increased.
Cogeneration Engine 1 heat recovery pump	215	Will require coordination with engine supplier. This value may change.
Cogeneration Engine 2 heat recovery pump	215	Will require coordination with engine supplier. This value may change.
Dump heat exchanger heating water pump	83	

Table 3-27 presents preliminary design criteria for the heating water primary loop pumps.

Table 3-27. Design Criteria for the Heating Water Primary Loop Pumps

Parameter	Value
Duty pumps	1
Standby pumps	1
Design flow per pump	1,000 gpm
Design head pressure per pump	TBD
Pump type	Horizontal end suction centrifugal
Motor speed	TBD
Maximum motor size	20 hp
Control per pump	Variable speed

Table 3-28 presents preliminary design criteria for the digester heat exchanger hot water recirculation pumps for each digester.

Table 3-28. Design Criteria for the Digester Heating Water Pumps for Digesters

Parameter	Value
Duty pumps, per digester	1
Standby pumps, per digester	0
Heating water temperature differential for this load	20°F
Design flow per pump	270 gpm
Design head pressure per pump	TBD
Pump type	Vertical Inline centrifugal
Motor speed	TBD
Maximum motor size	3 hp
Control per pump	Constant speed

The existing plant HVAC heating water pumps will remain unmodified. These pumps could be optimized to operate at a lower flow rate if the temperature drops across the individual heat loads are re-evaluated and increased. Currently the temperature drop for this entire heat loop is approximately 13°F. Flow rates for the heating water loop could be reduced if the temperature drop of this loop was increased to 20 to 30°F. The potential for reduction of flow rates in the secondary loop would also reduce the primary loop flow proportionally. If this pump were to be replaced, energy code would require the new pump to be variable speed.

Table 3-29 shows the design summary for the existing plant HVAC heating water pumps.

Table 3-29. Design Summary for the Existing Plant HVAC Heating Water Pumps

Parameter	Value
Duty pumps	1
Standby pumps	1
Heating water temperature differential for this load	13°F
Design flow per pump	285 gpm
Design head pressure per pump	78 feet
Pump type	Horizontal end suction centrifugal
Motor speed	1,800 revolutions per minute
Maximum motor size	10 hp
Control per pump	Constant speed

Table 3-30 shows the design criteria for the new Digester Control Building HVAC heating water pump.

Table 3-30. Design Criteria for New Digester Control Building HVAC Heating Water Pump

Parameter	Value
Duty pumps	1

Table 3-30. Design Criteria for New Digester Control Building HVAC Heating Water Pump

Parameter	Value
Standby pumps	0
Heating water temperature differential for this load	30°F
Design flow per pump	17 gpm
Design head pressure per pump	TBD
Pump type	Vertical Inline centrifugal
Maximum head pressure	TBD
Motor speed	TBD
Maximum motor size	¼ hp
Control per pump	Constant speed

Table 3-31 shows the design criteria for the new Digester Control Building HVAC heating water pump.

Table 3-31. Design Criteria for Gas Treatment Heating Water Pump

Parameter	Value
Duty pumps	1
Standby pumps	0
Heating water temperature differential for this load	20°F
Design flow per pump	22 gpm
Design head pressure per pump	TBD
Pump type	Vertical Inline centrifugal
Maximum head pressure	TBD
Motor speed	TBD
Maximum motor size	¼ hp
Control per pump	Constant speed

Table 3-32 shows the design criteria for the new Digester Control Building HVAC heating water pump.

Table 3-32. Design Criteria for New Cogeneration Building HVAC Heating Water Pump

Parameter	Value
Duty pumps	1
Standby pumps	0
Heating water temperature differential for this load	30°F
Design flow per pump	10 gpm
Design head pressure per pump	TBD

Table 3-32. Design Criteria for New Cogeneration Building HVAC Heating Water Pump

Parameter	Value
Pump type	Vertical Inline centrifugal
Maximum head pressure	TBD
Motor speed	TBD
Maximum motor size	¼ hp
Control per pump	Constant speed

Table 3-33 shows the design criteria for the new replacement Boiler 1 recirculation pump.

Table 3-33. Design Criteria for Boiler 1 Recirculation Pump

Parameter	Value
Duty pumps	1
Standby pumps	0
Heating water temperature differential for this load	20°F
Design flow per pump	525 gpm
Design head pressure per pump	10 feet
Pump type	Vertical Inline centrifugal
Maximum head pressure	TBD
Motor speed	TBD
Maximum motor size	2.5 hp
Control per pump	Constant speed

Table 3-34 shows the design criteria for Boiler 2 and 3 recirculation pumps.

Table 3-34. Design Criteria for Boiler 2 and 3 Recirculation Pumps

Parameter	Value
Duty pumps	Two (one per boiler)
Standby pumps	0
Heating water temperature differential for this load	20°F
Design flow per pump	335 gpm
Design head pressure per pump	10 feet
Pump type	Vertical Inline centrifugal
Maximum head pressure	TBD
Motor speed	TBD
Maximum motor size	1.5 hp

Table 3-34. Design Criteria for Boiler 2 and 3 Recirculation Pumps

Parameter	Value
Control per pump	Constant speed

Table 3-35 shows the design criteria for Cogeneration Engines 1 and 2 heat recovery pumps.

Table 3-35. Design Criteria for Cogeneration Engines 1 and 2 Heat Recovery Pumps

Parameter	Value
Duty pumps	Two (one per engine)
Standby pumps	0
Heating water temperature differential for this load	20°F
Design flow per pump	215 gpm
Design head pressure per pump	12 feet
Pump type	Vertical Inline centrifugal
Maximum Head Pressure	TBD
Motor speed	TBD
Maximum motor size	1 hp
Control per pump	Variable speed

3.5.3 Boilers

The existing boiler in the existing Digester Control Building will remain in service. Two new boilers will be installed in the new Digester 3 Control Building. Design criteria for boilers are summarized in Table 3-36.

Table 3-36. Boiler Design Criteria

Parameter	Design Criteria
Quantity	Three (two duty + one standby)
Existing boiler size	5,230 MBH
Firm boiler sizing criteria	6,076 MBH (2047 winter loads, no sludge heat recovery, one engine out of service)
Capacity new boilers, each	3,350 MBH, 80 hp, 30 psi; to be confirmed during Detailed Design
Fuel trains	Natural gas and pretreated digester gas
Candidate manufacturers	Hurst, Superior boiler, additional manufacturer(s) to be determined

Alternatively, if the cogeneration project is installed at the same time as the digestion expansion project, the new boilers could be installed inside the room where the existing cogeneration engines are located. Figure 3-5 shows the alternate boiler installation location at the existing cogeneration engine locations at the existing digester control building.

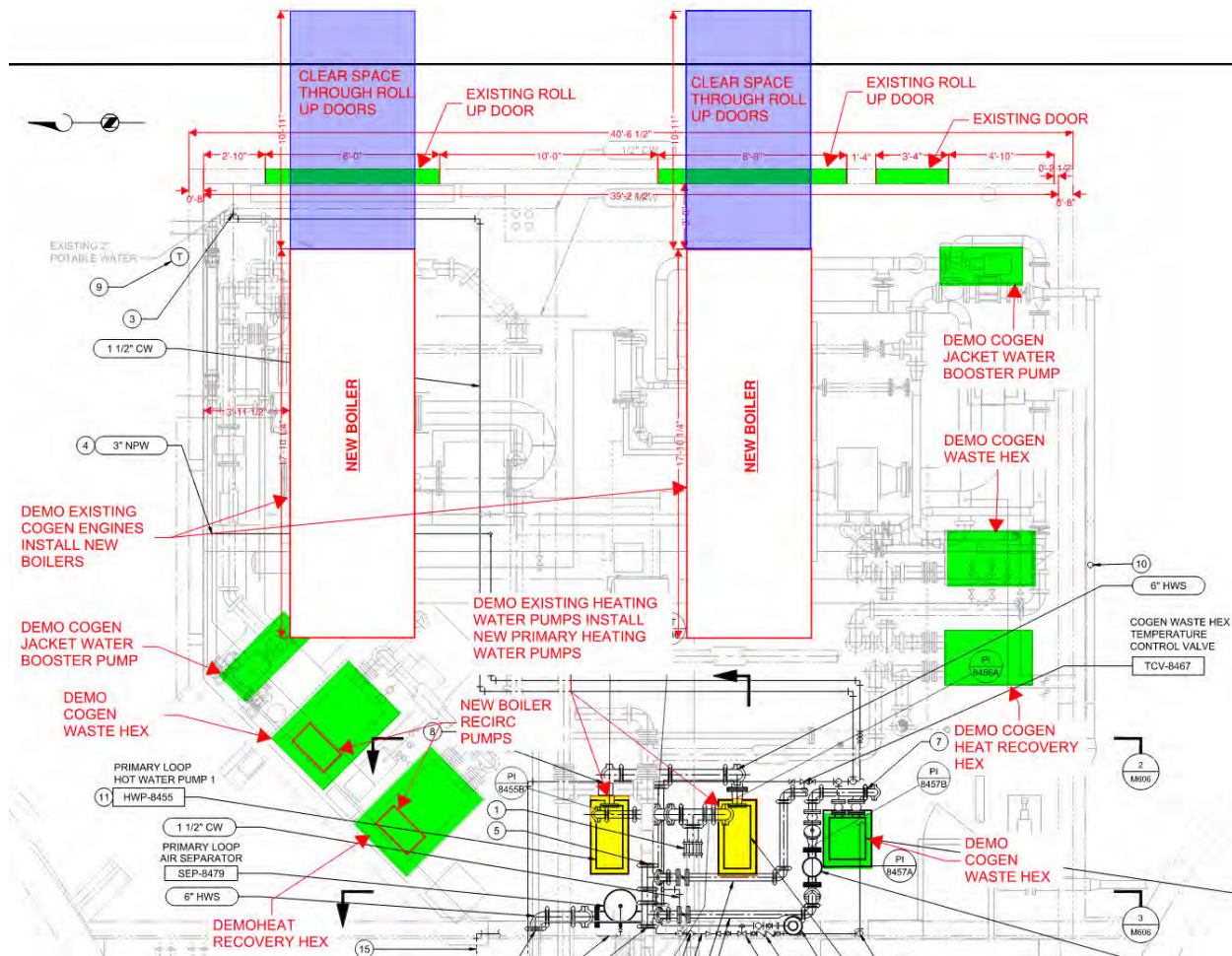


Figure 3-5. Alternate Boiler Installation Location

3.6 Biosolids Storage

3.6.1 Existing Facilities

The existing biosolids storage facility consists of nine covered concrete storage bins and an adjoining covered cake loading area. Six storage bins were constructed originally during the 1992 Solids Storage project, and the facility was modified to add three additional storage bins as part of the 2001 WWTP Expansion project. The storage facility contains a wooden roof frame and is covered by a metal roof, but contains large openings on all sides of the structure. Cake solids are transported from the Dewatering Building and dropped into the storage bins from the south side of the structure at a higher elevation, and flow by gravity to fill the bins. Stop logs located on the north end of the bins are removed for loading by gravity into larger trucks for year-round hauling. The City is investigating dewatering equipment replacement separate from this predesign, which is anticipated to improve dewatering performance and reduce dewatered cake solids percent.

3.6.2 New Facilities

With the anticipated increase in FOG receiving and the addition of FWS, solids production is expected to increase when the additional waste is accepted. The predesign assumes the additional loading will be accepted beginning in 2032, and in order to meet the 60 days of biosolids storage desired, the existing storage capacity needs to expand. The additional digested solids production from added FOG and FSW is shown in Figure 3-6, and Table 3-37 displays the additional days of biosolids storage provided by the expanded facility compared to the existing facility.

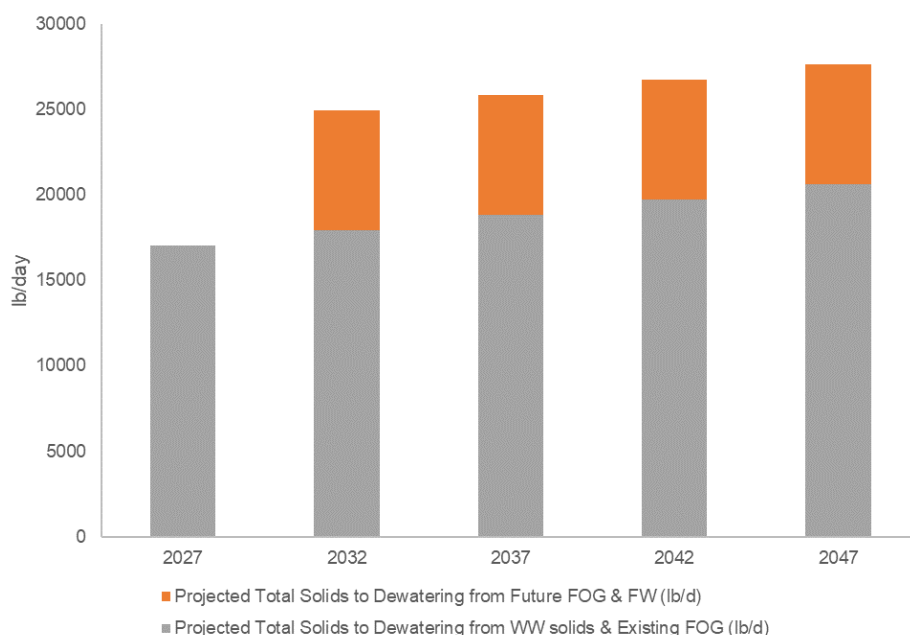


Figure 3-6. Projected Digested Sludge Loading to Dewatering

Table 3-37. Days of Biosolids Storage with Existing Infrastructure and Proposed Expansion

Condition	Days of Biosolids Storage*
2022 Average Loading; Existing Infrastructure	64
2047 Projected Loading with Additional FOG & FWS; Existing Infrastructure	37 (<60)
2047 Projected Loading with Additional FOG & FWS; Proposed Expansion	74

*Assumes 95% solids capture rate through dewatering equipment and 16% dewatered cake solids.

Proposed modifications to the existing storage facility extend and mirror the existing facility, such that a new truck loading lane will extend from the existing truck loading lane, eight additional storage bins will be constructed with a service bay in the center, a small unloading area for front loaders will be constructed on the north end of the facility, and a new 50-foot-wide unloading pad will be constructed to the north end of the facility. This modification will double the existing storage capacity from approximately 3,650 cubic yards to 7,280 cubic yards and provide additional operational flexibility. Structural modifications will be required to accommodate the addition to the existing facility. Additional excavation and paving will be required on the north side of the facility to allow for the construction of the unloading pad for the front loader trucks. Due to the steep grade in the area north of the existing biosolids storage facility, significant earthwork and regrading will be required, and a retaining wall will be required **to bring the grade level to the proper elevation for the unloading area**. A preliminary expansion plan and section are presented in the drawings, and the overall site plan shows the location of the retaining wall in relation to the expanded facility.

3.7 Wastewater Liquids Treatment System Impacts

The WWTP receives domestic, commercial, and industrial wastewater from incorporated areas of Gresham, Wood Village, and Fairview. A few of the Significant Industrial Users (SIUs) that discharge to the WWTP have entered into an agreement with the City of Gresham regarding expansions of their existing operations. Expansion of these operations would result in increased flows discharged into the City's sewer system and increase flow and ammonia loading to the WWTP. 1,000 lb/day of additional influent ammonia from the SIUs is anticipated to be received by the WWTP.

The City also accepts organic waste from commercial sources and co-digests with the solids produced at the WWTP. As part of this project the City is looking to increase their co-digestion capacity. Co-digestion of additional organic waste, specifically FWS, would result in additional ammonia and organic load being recycled through the WWTP via the dewatering filtrate recycle stream. This recycle stream is diverted to the lower plant only.

The recently issued NPDES permit (effective November 1, 2021, through August 31, 2026) for the WWTP includes final effluent ammonia limits (applicable in the dry-weather months only from May 1 through October 31) that will take effect March 31, 2025, unless the City can effectively demonstrate compliance with receiving water quality ammonia criteria prior to that time through a combination of outfall diffuser improvements to increase dilutions and potentially ammonia treatment modifications.

3.7.1 Model Development and Assumptions

To evaluate the magnitude of these sidestream impacts from the co-digestion of organic wastes on biological nutrient removal performance, a Jacobs' steady-state whole plant process simulator model Pro2D2 was developed and calibrated as part of the evaluation documented in *Impacts of Additional Ammonia Loading on the Gresham Wastewater Treatment Plant* (Jacobs, 2022b). The model was revised to reflect the addition of a third thermophilic digester, conversion of the existing mesophilic digesters to thermophilic operation, and to incorporate the additional HSOW being considered. Additionally, in order to be complaint with the NPDES permit in the near future, the upper plant was converted to include nitrification in the model.

A process flow diagram of the model setup is presented in Figure 3-7. The figure illustrates that only the lower plant aeration basins receive thickening and dewatering filtrate and would therefore be affected by recycle of organic and nutrient loading from co-digestion of additional HSOw.

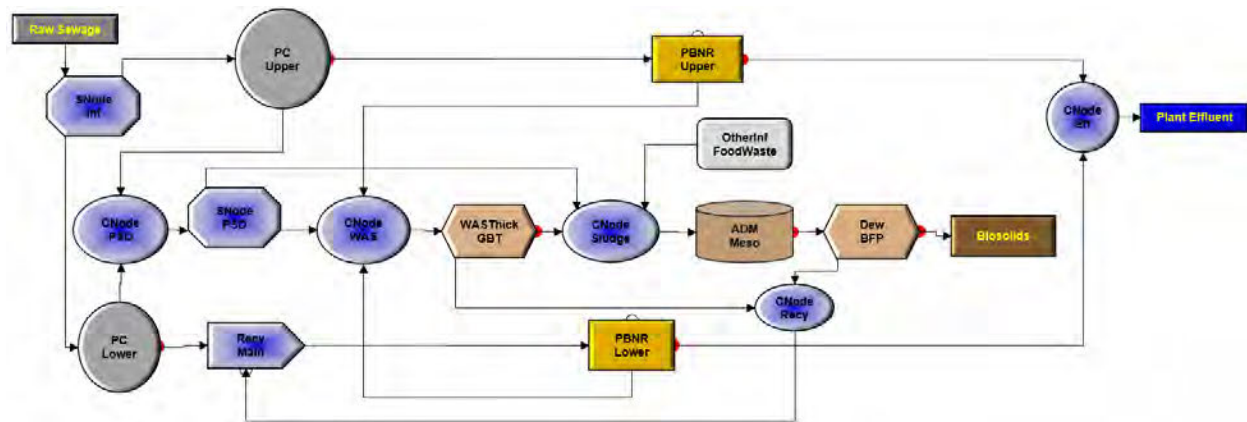


Figure 3-7. Pro2D2 Process Flow Diagram

Projected Year 2036 dry season maximum month conditions from the 2017 Master Plan, as summarized in Table 3-38, were used as the basis for evaluation.

Table 3-38. Projected Year 2036 Dry Season Maximum Month Conditions

Source: 2017 Master Plan

Condition	Units	Value
Flow	mgd	15.90
BOD ₅	ppd	28,101
TSS	ppd	27,235
Volatile suspended solids	--	89%

Table 3-38. Projected Year 2036 Dry Season Maximum Month Conditions

Source: 2017 Master Plan

Condition	Units	Value
Total Kjeldahl nitrogen	ppd/ mg N/L	5,046/ 38
Ammonia nitrogen	ppd / mg N/L	3,532 / 27
Alkalinity	ppd	38,000
Temperature	degrees Celsius	17

BOD₅ = 5-day biochemical oxygen demand; mgd = million gallons per day; mg/L = milligrams per liter; ppd = pounds per day; TSS = total suspended solids.

The values used for FOG and food slurry in the model were obtained from the 2020 Feasibility Study (Jacobs, 2020) and provided in Table 3-39.

Table 3-39. Influent Characteristics FOG and Food Slurry

Condition	Units	FOG	Food Slurry
BOD ₅	ppd	41,349	--
COD	ppd	--	38,364
TSS	ppd	18,714	25,020
Volatile suspended solids	%	92%	87%
Total Kjeldahl nitrogen	ppd	74	834
Ammonia nitrogen	ppd / mg/L	74 / 222	834* / 2,500*
Alkalinity	ppd	0	0
Temperature	degrees Celsius	20	20

*Worst case assumed that all total Kjeldahl nitrogen converted into ammonia nitrogen in the digester.

BOD₅ = 5-day biochemical oxygen demand; COD = chemical oxygen demand; mgd = million gallons per day; mg/L = milligrams per liter; ppd = pounds per day; TSS = total suspended solids.

To conservatively estimate the sidestream impact of additional HSOW, the process simulations assumed the total volume of HSOW to be 50,000 gpd, which is the maximum amount projected to be accepted at the WWTP (15,000 gpd currently accepted plus 35,000 gpd additional).

The influent flow and loading from the SIUs assumed in the analysis is summarized in Table 3-40.

Table 3-40. Influent Characteristics from SIUs

Condition	Units	Value
Flow	mgd	1.0
Ammonia nitrogen*	ppd / mg N/L	1,000 / 120

*Other constituents are assumed to be negligible for the analysis.

mgd = million gallons per day; mg N/L = milligrams per liter of nitrogen; ppd = pounds per day.

3.7.2 Model Results

Table 3-41 summarizes the relevant impacts resulting from the co-digestion of additional HSOW and additional influent ammonia loading from the SIUs on the effluent limits. Effluent limits are presented for two conditions: no nitrification and nitrification in the upper plant. The additional HSOW would increase organic and ammonia loading to the lower plant by approximately 100 ppd and 770 ppd, respectively for both conditions. The total required air rate in the lower plant aeration basins would increase by 7.5 percent with the addition of FOG and food slurry as all of the recycle stream is sent to the lower plant, and no increase in air demand for the upper plant. Air demand in the upper plant will also increase slightly due to higher influent ammonia loadings. Increased air demand is observed due to nitrification in the upper plant.

Table 3-41. Summary of Relevant Impacts Resulting from the Co-Digestion of Additional Food Slurry and Additional Influent Ammonia Loads from SIUs

Parameter	No Nitrification			Nitrification in Upper Plant Only		
	No Additional Food Slurry or FOG (Current Operations)	Food Slurry & Additional FOG	Additional Influent Ammonia from SIUs + Food Slurry & Additional FOG	No Additional Food Slurry or FOG (Current Operations)	Food Slurry & Additional FOG	Additional Influent Ammonia from SIUs+ Food Slurry & Additional FOG
Plant effluent total Kjeldahl nitrogen (mg N/L)	31	35	36	17	22	23
Plant effluent NH ₃ -N (mg N/L)	28	32	34	15	19	20
Total required air rate increase for lower plant blowers (%)*	0%	8%	9%	0%	9%	9%
Total required air rate increase for upper plant blowers (%)*	0%	0%	5%	120%	120%	130%

*Increase in air demand calculation for the upper plant and lower plant is compared against air demand for current operations with no nitrification for all conditions.

mg N/L = milligrams per liter of nitrogen.

3.7.3 Summary

The model results indicate that the effluent ammonia concentrations would increase with co-digestion of additional organic waste. The addition of influent ammonia from SIUs also impacts the effluent ammonia. The process impacts from the additional ammonia in the influent from SIUs and in the recycle streams from the co-digestion process will need to be further evaluated to ensure compliance with the NPDES permit for effluent ammonia.

3.8 Electrical Power Plan (including Utility Connection and Microgrid)

3.8.1 Existing Electrical System

The WWTP currently has one 12.47 kV PGE incoming service. In addition, the WWTP includes 360 kW of solar power generation and two ~400 kW cogeneration generators.

The WWTP service, located southeast of the Upper Plant Blower Building, consists of a medium voltage service switch and a PGE metering pad. The PGE metering includes a net meter that measures the aggregate power flow to/from the plant. Downstream of the metering equipment, the service switch then feeds MH-2 where power is distributed to MH-4 and a 2,500 kilovolt-ampere (kVA) transformer that feeds SWBD-378 (Upper Plant Blower Building). MH-4, which is located north of the Upper Headworks Building feeds a 600 kVA transformer that feeds SWBD-1189 (Upper Plant Headworks Building) and a 1,500 kVA transformer that feeds the power distribution center (Lower Plant Blower Building).

The solar power generation is located to the east of the Upper Plant Blower Building. It is connected to the plant 480 V power system via SWBD-3785 via a single 1,600 ampere (A) circuit breaker, and the array consists of a 260 kW inverter and a 100 kW inverter. The WWTP has two cogeneration generators, each rated at approximately 400 kW, located inside the Digester Control Building. They are paralleled at SWGR-8401 via 600AT circuit breakers, and ultimately connect to the Lower Plant Blower Building 480 V power distribution center via a 1200AT circuit breaker.

The WWTP has two 200 kW standby diesel generators. Standby generator GEN-1192 is located inside of Upper Plant Headworks Building, which is southeast of the Administration Building. The standby generator GEN-8473 is located east of Digester 2. GEN-1192 backs up SWBD-1189 (Upper headworks building). GEN-8473 backs up MCC-DD (Digester Control Building).

The electrical room in the Upper Plant Blower Building consists of SWBD-3785, MCC-3786, and MCC-3787. The SWBD-3785 has a 1,600 A circuit breaker available space and two 1600 A frame spare circuit breakers. The available space or spare circuit breakers can be used to feed a new MCC for this project. The existing electrical room in the Upper Plant Blower Building has some available space to install new power distribution equipment.

The Lower Plant Blower Building consists of two electrical rooms; one room is located on the north side and the other on the south side of the building. The north electrical room has MCC-BB, MCC-BB-A, and MCC-BC. The south electrical room houses a power distribution center and MCC-B. The location of the Lower Plant Blower Building is not advantageous to feed new facilities and electrical equipment. Therefore, these electrical rooms will not be taken into consideration as a power source for new loads and equipment.

The Digester Control Building has one electrical room. The electrical room has MCC-DD and MCC-DDD. MCC-DD has one 6-inch spare cubicle and five 12-inch spare cubicles to feed new loads. MCC-DDD has an available 6-inch and 12-inch cubicle to install a new circuit breaker. The electrical room in the Digester Control Building has no available space to install a new MCC. The cogeneration generator room houses SWGR-8401 which feeds each of the 398 kW cogeneration generators. The existing cogeneration generator room has no available space for new power distribution equipment necessary to support new loads or additional cogeneration units.

3.8.2 New Facilities

The following list indicates new facilities or electrical loads that require power, along with the recommended approach for providing power:

- New digester and associated control building: New MCC located in control building will be powered from new 480 V switchgear in the new Cogeneration Building.
- New cogeneration facility: New 480 V switchgear will connect cogeneration units. Switchgear will feed MCCs for all other loads.
- Expanded biosolids storage: A new 480 V feeder will be provided from the new Cogeneration Building.
- Gas treatment systems: One or more 480 V feeders will be provided from the new Cogeneration Building.

- FOG/FWS receiving area improvements: Power to these areas will be from existing power sources, likely within the existing digester control building.

3.8.3 Microgrid

A microgrid can benefit the Gresham WWTP in a number of ways, providing a more reliable and sophisticated power system. Major components of a typical microgrid include generation sources (cogeneration, diesel generators, solar, etc.), a battery, distribution equipment (switchgear and wiring), and a control system that governs the generation assets and communicates with the WWTP control system for load control. There are many configurations and operating principles, but inherent in any microgrid system is the ability to isolate from a larger electrical grid and run as “Island.”

The WWTP already has cogeneration, solar generation assets, and a 12.47 kV in-plant power network that connects to all generation sources and loads. The addition of a battery (with microgrid controller) or a 1 MW diesel generator, along with relocation of the cogeneration intertie, would allow the WWTP to implement a microgrid that allows the cogeneration units (and potentially the solar array) to directly power the WWTP power network. The microgrid would be classified as a “physical, non-utility owned microgrid.”

3.8.3.1 Microgrid Configuration Evaluation

An Energy Trust of Oregon (ETO) analysis was performed in June 2022 and serves as a basis for how various microgrid configurations could be implemented at the WWTP, along with high level cost estimates and benefits for each configuration. The four configurations examined in that report were as follows:

- **Microgrid Configuration 1:** Two cogeneration units + two diesel generators. No battery and assumes no solar used during an outage.
- **Microgrid Configuration 2:** Two cogeneration units + two diesel generators + solar. Smaller battery to enable solar integration.
- **Microgrid Configuration 3:** Two cogeneration units + one diesel generator + solar. Larger battery to make up for less diesel capacity.
- **Microgrid Configuration 4:** Two cogeneration units + solar. Largest battery sized for resilience and cogeneration auxiliary starting, assuming diesel generators not available.

The goals of implementing a microgrid, as outlined in the ETO analysis, include operating the WWTP during a 2 week regional PGE utility outage, offset operating costs, enhancing sustainability, and supporting the general WWTP goals to serve the community.

The report shows that there is not much opportunity for a microgrid to offset operating costs. However, all the microgrid configurations evaluated can support the 2-week outage, albeit at different levels of resilience (Microgrid Configuration 1 being least resilient, to Configuration 4 being the most resilient).

One drawback of gas powered cogeneration units is that they do not perform as well as diesel generators or batteries in terms of rapid load changes, which can be frequent for the WWTP as motors turn on/off regularly. This limitation can be offset by a paralleled battery or diesel generator that can perform the necessary voltage/frequency regulation and react much faster to load transients. Despite this limitation of gas engines, WWTP operators have indicated that when the WWTP electrical system was configured differently than it is today, the WWTP was able to establish an islanded grid and operate only cogeneration power. Jacobs’ understanding is that cogeneration units were able to successfully power the WWTP’s Lower Plant Blower Building, completely islanded from PGE. Some of the Lower Plant Blower Building largest loads operate on VFDs or soft starting controls, which helps ease the transient load profile to within manageable limits of the engines. With this successful history of operation, it would be likely that a similar system can be implemented today, enabling WWTP islanding via diesel generation.

Although a diesel generator powered islanding approach will help achieve the 2-week outage goals, it has the following drawbacks compared to a fully integrated, battery-based microgrid:

- Closed transitions (seamless power delivery) upon utility outages will not be possible. The WWTP will undergo short outages without a battery to immediately support WWTP loads and keep cogeneration units running. Transitions back to utility may still be able to achieve a closed transition.
- Increased reliance on diesel fuel storage and delivery. Diesel fuel deliveries may be difficult to procure due to a regional power outage causing a spike in demand.
- Increased burden on operators to perform islanding procedures. A fully integrated and battery backed microgrid would reduce the need to manually island the WWTP cogeneration engines from the regional grid.

Due to the higher capital costs and limited financial benefit of a more resilient, battery-based microgrid, something similar to Microgrid Configuration 1 is recommended to be implemented in the near term for the WWTP.

A new diesel generation source would be required to support the proposed approach. It is recommended that this generation source connect to the WWTP power system at the 12.47 kV distribution level. This allows for maximum flexibility in terms of powering cogeneration auxiliaries for islanding and also providing immediate and reliable power to critical WWTP loads. Implementing a single, larger diesel generator could allow for decommissioning of the two existing 200 kW diesel generators because this single generator would power the entire WWTP, instead of select loads as currently configured with two smaller engines connected at the 480 V distribution level. The generators could also remain as is as extra backup, with no adverse impact on microgrid. The new generator but must be sized at a minimum to power all the cogeneration auxiliaries, plus the magnetizing currents required to energize the 12.47-480 V transformers. The size does not need to be larger than the WWTP peak load, which is estimated at approximately 1.1 MW in the ETO analysis. This value should be confirmed via other methods. For the purposes of this predesign, a 1 MW generator is proposed. This generator could serve dual purposes, both assisting in islanding and as an integrated WWTP standby power source.

Diesel fuel storage requirements must be determined based on a number of factors, including fuel storage costs, availability of fuel during prolonged regional outages, sustainability goals, and the time needed to safely start cogeneration engines and have their power output available to the system. If sizing the fuel storage to assist with islanding alone, the requirement will be relatively small, on the order of a few-hours-worth of fuel at full load. If sizing fuel storage for more prolonged outages where cogeneration might not be available, the storage requirement could be up to 2 weeks in order to meet the goals outlined in the ETO analysis. Assuming 50 percent availability of cogeneration power during a prolonged outage, it is recommended that fuel storage not exceed 1 week. Further reduction in fuel storage requirements can be achieved with the understanding that overall resiliency is impacted. There could also be issues with running a standby diesel generator for an extended period of time. There are typically limits related to air permitting on how much a diesel generator can operate in a given year. Potential limitations on allowable operational duration should be further investigated.

For the WWTP to be able to fully utilize all the cogeneration at any location in the WWTP, the electrical system configuration must be modified. Primarily, the utility intertie must be relocated to a place on the system upstream of MH-2, near the main WWTP disconnect and PGE metering equipment. This will allow the cogeneration power and solar power to be delivered to the WWTP 12.47 kV network during an outage, which is necessary to get power to all WWTP loads. The current intertie point is at the Lower Blower Building power distribution center, at 480 V. The result is that during an outage this intertie breaker must be opened, which isolates the cogeneration to only a portion of the WWTP electrical system. For example, there is no way for cogeneration to power the upper plant aeration blowers in the current configuration. Coordination with PGE will be required to relocate the intertie and re-establish intertie protections and controls.

The detailed operation of this approach could work in a number of ways. One operational scenario that would closely match what the WWTP has done in the past, would be as follows:

- Upon regional power failure, automated transfer operations isolate the cogeneration engines and utilize standby diesel generation to re-power the WWTP. The cogeneration auxiliary equipment would be started using the power from standby diesel generator.
- After a short delay, the cogeneration engines could be automatically or manually started and synchronized with the standby diesel generator power.
- After a delay to ensure stable power, the standby diesel generator power could be turned off, depending on balanced power generation versus loading. Cogeneration units can only turn down so low before tripping offline, so proper system balancing is critical.
- On return of regional power, the WWTP power system would perform either a close or open transition back to grid power. Close transitions would be preferred and should be readily achievable. Cogen/utility paralleling controls are already included for typical operations.

Many other operational scenarios exist, including some that may allow the cogeneration engines to blackstart, that is to say, to start without any other standby power to auxiliaries such as oil pumps or cooling water. Blackstarted engines can start without external power sources; with this approach, critical auxiliary loads (such as pre-lubrication pumps) are immediately started once they receive power from the unit. This scenario is only recommended to be utilized in a true emergency situation and should not be considered a standard operating procedure.

3.8.3.2 Future, Fully Integrated Battery-Based Microgrid with Controller

Although not recommended until later construction phases, the following describes considerations and recommendations for fully integrated microgrid, including a battery. This would be roughly equivalent to the ETO analysis for Microgrid Configuration 4.

Battery

The battery would connect to the power system most likely at the 12.47 kV distribution level. This would allow the battery to power the entire WWTP and operate in parallel with solar and cogeneration power sources. Interconnection to the WWTP grid would be via a power inverter, similar to inverters serving the solar power field. The battery inverter may include an integral step-up transformer to achieve 12.47 kV, or the step-up transformer can be provided separately. Transformer capacity would closely match the battery capacity in terms of kW/kVA rating. The 12.47 kV WWTP distribution currently has two spare connection points, one at MH-2 and one at MH-4, that could be used to connect this inverter/battery system.

Sizing of the battery must account for how much power can be delivered instantaneously (kW) and how much energy can be stored (kilowatt-hours [kWh]). The ETO analysis showed various battery sizes for the microgrid configurations. The largest battery considered in the analysis was 500 kW, with an energy storage capacity of 4,500 kWh. This resulted in the highest resilience factor and annual savings for all the configurations, but at the largest capital cost. To get an idea of physical scale, a battery suitable for the size of this WWTP would be housed in a container similar to the size of a small railcar. The estimated cost to provide this battery system and necessary support components is \$9 million, which is significantly higher than the cost of the proposed larger diesel generator with islanding capabilities. Therefore, the cost estimates for the predesign report will be based upon implementing the solution using a new 1 MW diesel generator.

Microgrid Controller

The microgrid controller is the heart of an automated microgrid system. It communicates to and controls all generation assets, governing their connection to the WWTP power system and ultimately the regional grid (when not in island mode). Microgrid controllers are available from many suppliers well known in the industry, such as Eaton, Schneider, and Siemens.

Some microgrids involve communication to regional utility control systems, allowing the utility to control and manage generation assets within the WWTP. This level of sophistication was not evaluated by the ETO

analysis and is not being proposed for this project. Future facilitation of this type of control could be implemented if desired.

In the event of a microgrid failure, the WWTP has existing standby diesel generators to power a select set of the most critical loads, which is the current form of operation. A microgrid control system would likely not be required to communicate or integrate with the standby diesel generators. Standby generator operations would utilize current control schemes and equipment, separate from the microgrid. This makes for a less complicated control scheme, and eliminates the cost of integrating these assets with the larger microgrid system. The smaller size of these standby generators (200 kW each) reduces their potential positive impact on the microgrid. It could also be likely that their added generation capacity is not required when the other preferred microgrid generation assets (cogeneration and solar) are producing power.

3.9 Geotechnical Site Needs Assessment

This section briefly summarizes the existing geotechnical information, subsurface and groundwater conditions at the project site, and the proposed geotechnical investigation plan to support design of the new facilities for the project. The Geotechnical Technical Memorandum (copy provided in Appendix B) includes detailed discussion of the subsurface conditions, groundwater conditions, seismic design considerations, foundation design, general geotechnical considerations, and the proposed geotechnical investigation plan.

3.9.1 Existing Information

Geotechnical information related to subsurface conditions and geotechnical properties at the Gresham WWTP site is available from the previous geotechnical explorations completed at various locations within the project site:

- Shannon and Wilson advanced three borings in 1979 and two borings in 1982
- Geotechnical Consultants advanced eight borings in 1986
- CH2M HILL advanced four borings in 1992
- Fujitani Hilts and Associates advanced ten borings in 1997
- Hart Crowser advanced three borings and four drive probe soundings in 2017

Details of the boring locations, borings depth, historical groundwater measurements, and boring logs are included in the Geotechnical Technical Memorandum (copy provided in Appendix B). Approximate locations of these borings are also shown in Figure 3-7.

3.9.2 Subsurface and Groundwater Conditions

The general subsurface soil profile is described here based on the geotechnical data from the existing geotechnical explorations, and a review of the regional geologic conditions:

- Fill consisting of loose to medium dense silty sand (SM) and soft to medium stiff silt, silt with sand, and sandy silt (ML) with occasional gravel and construction debris. This layer is underlain by the alluvium or by weathered Troutdale Formation.
- Alluvium consisting of brown loose to medium dense silty sand (SM) and firm to stiff non-plastic silt (ML) was encountered in certain borings. This unit is present overlying the Troutdale Formation.
- Troutdale Formation consisting of lightly to strongly cemented poorly graded sand (SP), poorly graded sand with silt (SP-SM), well graded sand (SW), and poorly graded gravel (GP). This unit underlies either the fill or the alluvium layer.

The historical groundwater data indicate that in the vicinity of the High Strength Organic Waste Receiving Expansion, Thermophilic Digester, Digester Control Building, and Gas Storage facilities the groundwater is at about 23 feet below ground surface in the very dense Troutdale Formation. Data of the seasonal

variability of groundwater are limited. Groundwater data are not available in the immediate vicinity of the Cogeneration Facility, Biosolids Storage Facility, and the Waste Gas Burner.

3.9.3 Proposed Geotechnical Investigation Plan

The proposed geotechnical exploration program consists of eleven borings at the new facility locations, two of which will include standpipe piezometers including vibrating wire piezometers. Standard penetration test (SPT) N-values will be documented and laboratory testing of SPT samples conducted for physical analysis of selected samples. The proposed borings, along with approximate locations of previously completed geotechnical explorations, are shown in Figure 3-8. The layout of proposed borings is based on the site plan; the locations would be changed if the layout changes.

Currently, shear wave velocity data are not available at the project site. The proposed geotechnical investigation will include measurement of shear wave velocity using geophysical methods for soil site classification for the project area per American Society of Civil Engineers (ASCE) 7-22, Chapter 20 (ASCE, 2022). The site class will be used for the assessment of the geotechnical seismic hazard for the project.

Changes in the nature, design, or location of the planned facilities will require an update of the proposed geotechnical exploration plan.

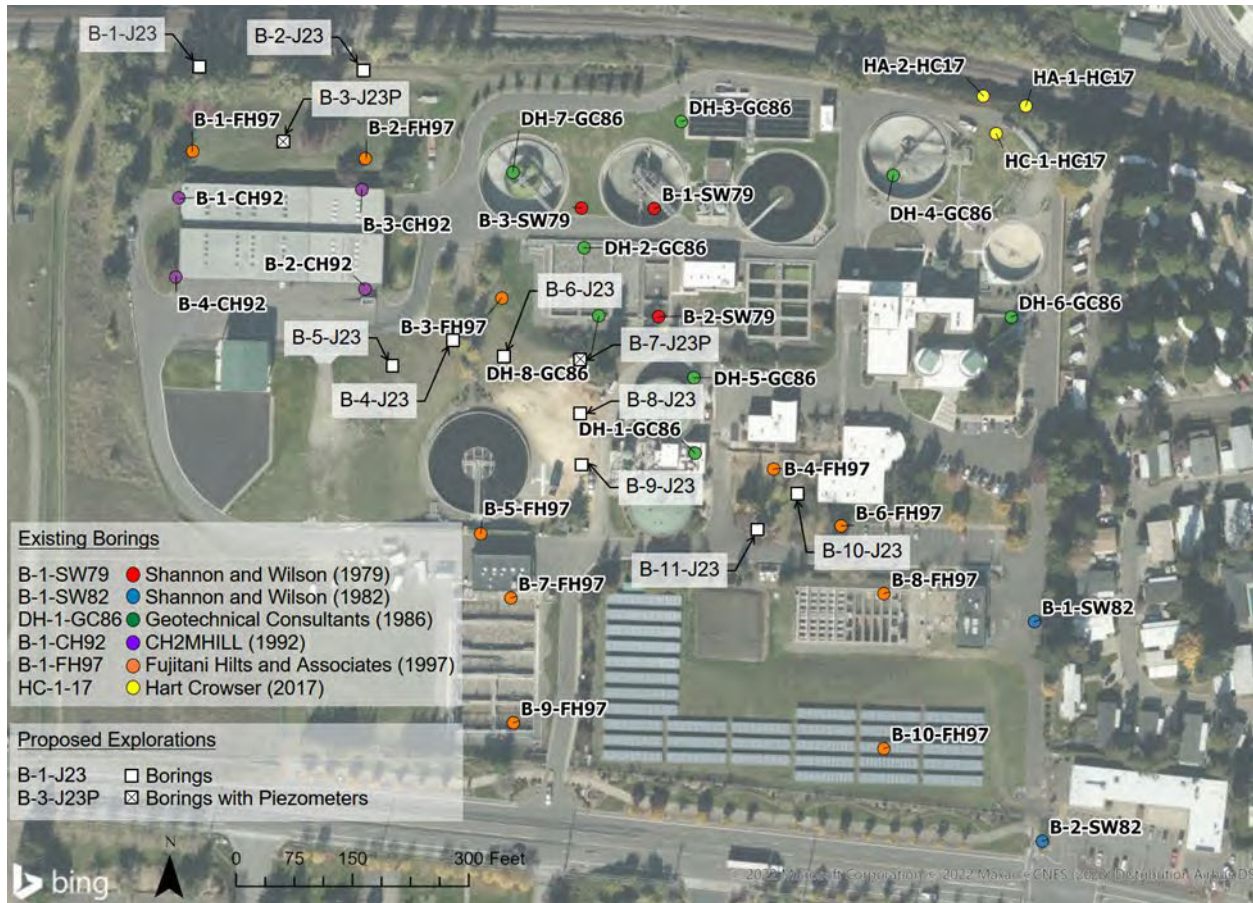


Figure 3-8. Historical and Proposed Boring Locations

3.10 Permitting

3.10.1 Building Codes

Permitting of project improvements is anticipated to occur under the 2022 Oregon Structural Specialty Code (OSSC), both for new facilities and modifications to existing structures. The work area compliance approach in Chapter 34 of the OSSC considers three levels of alterations to existing structures:

- Level 1: Removal and replacement or covering of existing materials, elements, equipment or fixtures using new materials, elements, equipment or fixtures that serve the same purpose.
- Level 2: The addition or elimination of any door or window, the reconfiguration or extension of any system, or the installation of any additional equipment, where the work area is equal to or less than 50 percent of the building area.
- Level 3: Alterations where the work area exceeds 50 percent of the building area.

Structural systems under a Level 1 alteration are required to be not less compliant with the building code provisions for new structures than before the alteration, unless forces in gravity load-carrying elements increase not more than 5 percent or roof coverings weighing not more than 3 pounds per square foot are added. Consideration of lateral loads including wind and seismic forces is required for Level 2 and 3 alterations. If gravity loads increase more than 5 percent or lateral loads more than 10 percent in a structural element, that element is required to be replaced or altered as needed to meet the provisions for new construction for a Level 2 or 3 alteration. An added layer of roof covering of no more than 3 pounds per square foot, however, does not require upgrades. Provisions for new construction apply to all additions.

Based upon preliminary evaluations, it is expected that the existing structures to be modified will meet the requirements for work area compliance under the OSSC without need for extensive upgrades. However, the existing FOG tank foundations are an exception. Meeting the design requirements for seismic load resistance will require replacement of the existing foundations due to the higher overturning demands from the larger tanks in addition to the limited space available.

For concrete structures, structural design for WWTP facilities typically requires tighter limits on reinforcing steel stresses under service loads than required by the OSSC to keep crack widths small. This is done to reduce the potential for corrosion of the reinforcing steel. The preliminary analyses performed indicate that the existing digesters can be converted to operate under thermophilic conditions without wall retrofits. Reinforcing steel stresses fall within the range allowed by American Concrete Institute 350 for normal environmental exposures, acceptable for the levels of pH and sulfates at which anaerobic digesters perform acceptably.

Compliance with the 2021 Oregon Energy Efficiency Special Code (OEESC) is also required for new elements of alterations. However, alterations up through Level 3 do not require the entire building or structure to conform to the energy requirements of the OEESC.

3.10.2 NFPA-820 Compliance

The existing Digester Control Building built in 1987 does not meet current National Fire Protection Association (NFPA) 820 code. To comply with the current NFPA 820 code, the building would require modifications to the HVAC systems to prevent potential of explosion hazards caused by the proximity to the anaerobic digesters. To reduce the risk of ignition in these classified areas, explosion-proof equipment can be purchased, but because ignition can still occur from transient sources, it is best to protect the facility from explosion classifications through physical separation and proper ventilation. To accomplish this, all existing openings within 10 feet of the existing digesters will be required to be sealed. All new openings will be located outside the 10-foot-wide classified areas. This requirement applies to openings for both supply and exhaust, as well as louvers and doors. The proposed modifications are identified in the following drawings:

- Drawing 20-A-1020: Ground Floor Plan of Existing Digester Control Building
 - Louvers at ground floor southeast side of building: Blank off louvers inside the classified areas that occur within the classified envelope of the digester. Remove gas handling equipment near louver and entry door.
 - Door to stairwell on northeast side of building: Create a new vestibule to extend entry outside of classified areas.
 - Common wall construction to digesters: Provide coating to the wall inside digester to prevent any possibility of gas passing through a crack in the wall.
- Drawing 20-A-1040: Penthouse Plan of Existing Digester Control Building
 - Air-handling unit intake proximity to north digester: Modify intake location to be outside of classified areas.
 - Multiple exhaust fan proximity to digesters: Relocate exhaust fans outside of classified areas.
 - Door from stairwell to roof on east side of building: Relocate door or blank off door.

For new facilities, to avoid exposing the WWTP to NFPA classified hazards defined in NFPA 820, the project architect will work with the mechanical and structural designers to move and seal openings in walls and roof to physically separate occupied areas from hazard classified areas. HVAC systems will be designed to properly ventilate areas to declassify areas that cannot otherwise be physically separate from hazardous classifications.

WWTPs have various sources of combustible gas. NFPA 820 determines the level of hazards in each space or area and offers acceptable mitigation techniques and monitoring requirements.

Mitigation techniques include creating physically separated spaces, ventilating with fresh air, and monitoring with combustible gas detectors. When ventilation systems are operating correctly and no dangerous gas concentrations are detected, green "GO" lights outside and inside the facility will be illuminated. If ventilation failure is detected or dangerous concentrations of combustible gases are detected, red warning "NO GO" lights will flash and audible alarms will activate, indicating the buildup of combustible gas is possible.

Monitoring with combustible gas detectors will also be installed in facilities where digester gas is handled, as required by NFPA 820.

Hazardous locations are classified as follows:

- Class 1, Division 1 locations may collect combustible gas in explosive concentrations under normal operating conditions. Electrical equipment in these locations must be explosion proof.
- Class 1, Division 2 locations may collect combustible gas in explosive concentrations under abnormal operating conditions. Electrical equipment and installations must be rated for a Class 1, Division 2 location.

3.10.3 Special System Requirements

Go/No-Go lights and audible alarms will be provided at new and existing buildings being modified in this project as required by NFPA 820. Alarms associated with combustible gas detection and Go/No-Go lights will be communicated back to the WWTP SCADA.

Basis of design includes provisions so there is no need for additional special system requirements such as CCTV. It is expected that these facilities could be designed with the square footage, chemical usage, etc., kept below the code requirements that require fire sprinkler systems.

3.10.4 Air Permitting Review

The Anaerobic Digestion and Cogeneration Expansion project includes expanding the WWTP's high strength organic digestion capacity. The preliminary design includes the following equipment that have an impact on air quality:

- New odor controls
- Modifications to existing digesters
- A new anaerobic digester
- Replacement of an existing flare with a new flare
- Additional digester gas powered cogeneration
- New boilers
- A new biogas cleaning system

The combustion equipment is subject to air quality permitting review, but all equipment contributes to the facility meeting its Plant Site Emission Limit (PSEL), visible emissions and nuisance requirements.

The following information addresses only the regulations that may be applicable to the project. Emissions associated with the project include criteria pollutants, Hazardous Air Pollutants (HAPs) and greenhouse gases. The Northwest Region of the Oregon Department of Environmental Quality (DEQ) has primary jurisdiction over the WWTP and the facility operates under Simple Air Contaminant Discharge Permit (ACDP) Number: 26-3228-SL01. This section presents a summary of the permitting procedures and pertinent state and federal regulations.

3.10.4.1 Oregon DEQ Permitting Procedures

In July 2001, the Oregon Environmental Quality Commission adopted a comprehensive set of revisions to the Oregon air quality permitting program. The intent of the revisions was to reduce the number of site-specific air permits written and issued by the DEQ, allowing the agency to focus more on permitting and enforcement with attention on larger sources of air pollutants in the state. These revisions more closely align Oregon New Source Review procedures with federal procedures.

Under the revised rules, there are three categories of ACDPs: standard, simple, and general. General permits are issued to a large number of small sources in the state that fall into specific source categories. Simple permits are issued to small sources that do not fit into the existing source categories. Standard permits are issued to larger sources. Gresham WWTP has a simple permit.

Any person requesting a new, modified, or renewed Simple ACDP must submit an application to DEQ according to Oregon Administrative Rules (OAR) 340-216-0040. The permittee must notify DEQ in writing using a Departmental "Notice of Construction Form," or "Permit Application Form," and obtain approval in accordance with OAR 340-210-0205 through 340-210-0250 before:

- a. Constructing, installing, or establishing a new stationary source that will cause an increase in any regulated pollutant emissions;
- b. Making any physical change or change in operation of an existing stationary source that will cause an increase, on an hourly basis at full production, in any regulated pollutant emissions; or
- c. Constructing or modifying any air pollution control equipment.

The permitting process includes four different levels of review and approval for the Notice to Construct application and approval. Changes with the highest environmental and public health significance will receive more comprehensive review. Minor changes may proceed 10 days after submitting the required information. DEQ may add new requirements to existing Simple or Standard ACDPs by assigning the source an ACDP Attachment according to OAR 340-216-0068. An ACDP Attachment would apply to an

affected source until the new requirements are incorporated into the source's Simple or Standard ACDP at the next permit renewal or at the time of permit modification.

3.10.4.2 State Regulations

The WWTP is considered a minor source of criteria pollutants with PSEs for nitrogen oxides (NO_x), sulfur dioxide, carbon monoxide (CO), and volatile organic compounds of 39 tons per year of each pollutant. The WWTP is an area source of HAPs. Area sources are facilities that emit or have the potential to emit less than 10 tons per year of a single HAP, or less than 25 tons per year of combined HAP.

Facility-wide Requirements

The following regulations are general emission standards that apply to all stationary sources at the facility and will be applicable to the new boilers and cogens. General emission standards and limits for new combustion equipment are stated in OAR Chapter 340 Divisions 208, 226 and 228 and include:

- Visible emission
- Particulate matter emissions
- Fugitive emissions
- Particulate matter fallout
- Nuisance and odors
- Fuels and fuel sulfur content

Gresham's current Simple ACDP includes these emission standards, and the requirements should not change due to the project.

OAR Chapter 340-226 includes Section 0130 which defines the *Highest and Best Practicable Treatment and Control: Typically Achievable Control Technology (TACT)*. For new and modified sources, the TACT emission limit established will be typical of the emission level achieved by well controlled new or modified emissions units similar in type and size that were recently installed. TACT determinations are based on information known to DEQ while considering pollution prevention, impacts on other environmental media, energy impacts, capital and operating costs, cost effectiveness, and the age and remaining economic life of existing emission control devices.

Clean Air Oregon Rule

In November 2018, Cleaner Air Oregon (CAO), a risk-based approach to facilities' toxic emissions, was implemented to overhaul Oregon's prior toxics program. Under Oregon's CAO toxics program, existing facilities in the state have been given a prioritization score, with higher scoring facilities entering the program sooner. A Notice of Intent to Construct for toxic air contaminants under CAO is only required for sources that have been issued a Toxic Air Contaminant Permit Addendum. It is Jacobs' understanding that the Gresham WWTP currently does not have a Toxic Air Contaminant Permit Addendum.

Registration and Reporting of Greenhouse Gases

If the calendar year emission rate of greenhouse gases (CO₂e) is greater than or equal to 2,756 tons (2,500 metric tons), the permittee must register and report its greenhouse gas emissions with DEQ in accordance with OAR 340-215.

Land Use Compatibility Statement

All ACDPs require a Land Use Compatibility Statement prior to permit issuance. DEQ must ensure that an operation is complying with local land use jurisdiction. Land Use compatibility will be verified with the permitting departments during detailed design for each phase of the project.

3.10.4.3 Federal Regulations

The New Source Performance Standards (40 CFR Part 60)

The New Source Performance Standards (NSPS) are uniform national U.S. Environmental Protection Agency (EPA) air emission standards that limit the amount of pollution allowed from new sources or from modified existing sources.

Part 60, subpart Dc, of Title 40 of the *Code of Federal Regulations* (40 CFR pt. 60, subpart Dc) applies to steam-generating units for which construction, modification, or reconstruction is commenced after June 9, 1989, and that have a maximum design heat input capacity of 100 MMBtu/hr or less but greater than or equal to 10 MMBtu/hr. The new boilers will be rated at less than 10 MMBtu/hr; therefore, the subpart will not apply.

40 CFR 60 Subpart JJJJ sets national standards for Stationary Spark Ignition Internal Combustion Engines. Generators installed after June 12, 2006, are subject to the NSPS requirements. The date of construction is the date the engine is ordered by the owner or operator. The size of the engine will determine the level or tier of standards required. The pollutants regulated by the final rule are nitrogen oxide (NO_x), particulate matter, CO, and nonmethane hydrocarbons. Emissions of sulfur oxides will be reduced through the use of lower sulfur fuel.

National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)

The National Emission Standards for Hazardous Air Pollutants (NESHAP) are national emissions standards set by the EPA for an air pollutant not covered by National Ambient Air Quality Standards that may cause an increase in fatalities or in serious, irreversible, or incapacitating illness. Primary standards are designed to protect human health, and secondary standards are designed to protect public welfare (e.g., building facades, visibility, crops, and domestic animals).

The National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (40 CFR pt. 63, subpart ZZZZ) establishes emission and operating limitations for HAPs emitted from stationary reciprocating internal combustion engines located at major and area sources of HAP emissions. The new cogens will be located at an area source of HAPs; therefore, Subpart ZZZZ applies. However, the engines can meet the requirements of this subpart by meeting the conditions of 40 CFR 60 Subpart JJJJ for spark ignition internal combustion engines.

The EPA has adopted a NESHAP for Publicly Owned Treatment Works in 40 CFR Part 63 subpart VVV. The provisions of that subpart apply to new and existing wastewater treatment works that have the potential to emit 10 tons per year of any listed HAP or 25 tons per year of all HAPs combined, or if an industrial user complies with its NESHAP by using the treatment and controls located at the Publicly Owned Treatment Works plant. The WWTP currently emits less than 10 tons of all HAPs combined and will continue to emit less than 10 tons of all HAPs combined after the modifications are complete. The WWTP is also not used by an industrial user to comply with a NESHAP; hence, it is not subject to 40 CFR 63 subpart VVV.

The National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (40 CFR pt. 63, subpart JJJJJ [6J]), March 21, 2011, applies to existing and new industrial boilers, institutional boilers, and commercial boilers located at area sources of hazardous air pollutants. Boilers that burn only gaseous fuels are exempt from the rule. As defined by 6J, gaseous fuels include, but are not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas. Since the boilers are located at an area source of HAPs and will only burn gaseous fuels, biogas and propane, the boilers are exempt from Subpart 6J.

For major sources of HAP emissions, EPA has developed Maximum Achievable Control Technology (MACT) standards for publicly owned treatment works. The MACT for publicly owned treatment works is applicable only to facilities that are a major source of HAP emissions. The Gresham WWTP is considered to be an area source of hazardous air pollutants and not a major source, so the MACT is not applicable.

3.11 Projected Schedule, Constraints, and Phasing

It is understood that these improvements will likely need to be constructed through a phased sequence of separate projects. In order to allow continued operation of the solids facilities, it will be critical that during design each project identify the constraints the contractor will need to follow in order to minimize disruption to the normal WWTP operations. These constraints will tend to extend the overall duration of the project schedules. If all these facilities were to be constructed as one project, it is anticipated that the overall duration of construction could be 24 to 36 months due to the sequential construction requirements for this project. Once the scope of each project is further developed during design, a detailed preliminary construction schedule can be developed to more accurately estimate the construction duration for that project.

3.11.1 Construction Constraints

The overall constraints that have been identified for this preliminary deliverable are as follows:

- **Operational Constraints.** Improvements and connections to existing facilities often require shutdowns of unit processes to allow those connection to be made. It is critical that these connections be identified in the construction documents and that the contractors are informed of any time constraints required with each shutdown so they can plan accordingly. Relocation of existing yard piping (30-inch-diameter PE and 8-inch-diameter WAS lines) will require carefully planned shutdowns or temporary pumping/piping installations that would need to be identified in contract documents. Other constraints will be influenced by seasonal influent flow characteristics. Cold weather and the related digester and facility heating demand may drive timing of improvements (or provision of temporary facilities) to reduce risk of digester heating system failures and consequences of heating system outage. These constraints will be identified during detailed design for each project.
- **Biosolids Storage Expansion.** The expanded storage area could be constructed on the north end of the facility without interrupting existing operations. After the new expansion is complete, modification for access into the existing facility could be constructed in a manner to minimize interruption to continuous storage and handling of produced biosolids.
- **Electrical Facility Upgrades.** Upgrades to the existing electrical facilities would be performed throughout construction; new utility power feeds would need to be constructed prior to bringing any new facilities online. Consideration should be given to making allowances for future construction projects.
- **New Digester and Digester Control Building.** The existing digestion facilities currently lack any redundancy in capacity, which means that the new Digester 3 must be constructed and operational before existing digesters are taken out of service for the proposed improvements.
- **Existing Digesters and Digester Control Building.** The existing digesters and control building must remain in continuous operation until the new digester and digester control building facilities are operational. The startup of the new digester and interconnections with the existing heating loop and sludge feed and withdrawal facilities must be coordinated. The floating cover in existing Digester 2 provides an operational buffer for storage of excess digester gas; construction of new gas storage facility will need to be completed prior to beginning any of the retrofits on the existing digesters. Additionally, retrofits to the existing digesters must occur sequentially, leaving one of the existing digesters and its support equipment online while making improvements to the other existing digester. The existing boiler and heating recirculation pumps will need to remain in service until the new boiler(s) and heating water system are operational.
- **Heating, Ventilation, and Air Conditioning Facilities.** Any required HVAC improvements identified for NFPA compliance do not specifically require sequencing constraints. However, consideration will need to be given to temporary ventilation while the existing system is being replaced to maintain the required ventilation in the Digester Control Building during construction.

- **Existing FOG and New FWS Receiving Systems.** It appears that the existing FOG receiving system could remain operational through most of the construction activities. The FWS receiving system could be constructed and commissioned independently of activities for the improvements on the FOG receiving system. The upgrades to the existing FOG receiving system could be phased to allow the system to remain operational; however, this would most likely result in reduced capacity until the upgrades are completed.
- **New Cogeneration Facility.** The new cogeneration facility would need to be constructed prior to making any modifications to the existing cogeneration system, heat loop, and boilers. This could be constructed while the existing systems remain operational and would only require a shutdown for switchover.
- **Existing and New Gas Treatment Systems.** The older waste gas burner will need to be demolished to allow the FOG improvements to be constructed. The new cogeneration and digester gas cleaning facilities must be constructed prior to decommissioning the old cogeneration engines and gas cleaning system. The construction of new gas treatment system for the RNG treatment (including injection into the NWN line along Sandy Boulevard) will not constrain operational use of any existing facilities or construction of new facilities, and is only required if they City decides to move ahead with selling cleaned biogas to the utility.
- **Site Utilities (Plant Water, Compressed Air, Stormwater, Potable Water, Natural Gas).** Tie-ins to existing site utilities are not yet defined. This activity will be completed during the detailed design phase.

3.11.2 Project Phasing

The constraints listed above help determine the required sequence for implementation of the proposed improvements. Considerations can be made during detailed design to allow maximum flexibility for implementation of other future proposed improvements. The following project phasing is recommended but could be modified based upon available funding:

- Phase 1 (Digestion Expansion)
 - Relocate 30-inch-diameter PE and 8-inch-diameter WAS lines
 - Construct new thermophilic digester (existing digesters continue to operate at mesophilic temperatures)
 - Construct new Digester Control Building
 - Construct new dewatering feed tanks
- Phase 2 (Existing Digester Upgrades)
 - Construct gas storage facility
 - Existing Digester 1 and 2:
 - Replace covers – existing covers may need to be prioritized sooner than this proposed phasing due to the gas leak, recommend continuing to monitor the condition.
 - Convert to thermophilic operation
 - Construct required seismic retrofits
 - Existing Digester Control Building:
 - Upgrade ventilation and monitoring system to comply with NFPA-820 guidelines
 - Construct required seismic retrofits
- Phase 3 (Liquid Organic Waste and Biosolids Storage Expansion)
 - Demolish existing waste gas burner

- Expand HSOW (FOG and FWS) receiving infrastructure
- Expand biosolids storage
- Phase 4 (Cogeneration Facility)
 - Construct new cogeneration facility
 - Construct digester gas treatment facility
 - Construct RNG treatment facility
 - Install microgrid system with diesel or battery back-up

The Phase 1 project is required to be completed and online before any of the other projects begin. The other three phases could be constructed concurrently but should be brought online in the order presented.

4. Economic Model Update

In December 2022, EPA unveiled their proposed rules for the next 3 years, 2023 through 2025 (<https://www.epa.gov/renewable-fuel-standard-program/proposed-renewable-fuel-standards-2023-2024-and-2025#rule-summary>). This was discussed at the end of the *Task 2.6 - Power Utility Coordination and Preliminary Economic Model Update Technical Memorandum* (Appendix A-4), but the changes are summarized here.

There were two significant developments

1. eRINs are moving forward. This means that EPA is making eRINs approximately 3 times more valuable. Currently, automakers are in the lead, unless the EPA is persuaded to change their minds.
 - a. Outcome: making electricity from biogas could become much more attractive.
2. EPA is proposing to get rid of the D-3/D-5 constraint – so codigestion can occur without having to downgrade the D-3 RINs from municipal WWTP sludge to the less valuable D-5 RINs.
 - a. Outcome: removes the barrier of codigestion reaping reduced benefit, and removes the driver to build separate tankage to digest food slurry separately from municipal WWTP solids.

These two updates from the EPA are examples of the quickly changing energy landscape that impacts the business case evaluation for the Gresham WWTP digestion expansion project. These updates also highlight the importance of flexibility designed into the system to reduce risk in the changing energy landscape, which is why carrying the hybrid option allows for the most future flexibility with electricity and RNG production capabilities.

The cost estimate completed in this phase of the project is considered a Class 4 estimate under Advancement of Cost Engineering (AACE) International recommended practices and is included in Appendix E. Figure 4-1 shows the status of design development relative to AACE International Publication 18R-97 (2011), which is intended to reduce the probability of a project cost overrun or underrun to less than 50 percent. Per AACE International, the expected accuracy range of a Class 4 estimate is minus 20 to minus 30 percent on the low end, and plus 30 to plus 50 percent on the high end. The accuracy factors are applied based on professional judgement of the estimator and owner/organizational experience with cost estimating.

The cost estimate for this project was based on the use of conceptual and stochastic costs and detailed items using separate labor, materials, and equipment costs. The estimate uses parametric costs where design information or details are insufficient to allow a detailed item method. Quotations, allowances, and other costs are as described in the estimate. The estimate is considered a construction cost estimate that includes a 25 percent design contingency but engineering, legal, and administrative (ELA) support and the Gresham administration fee were not included.

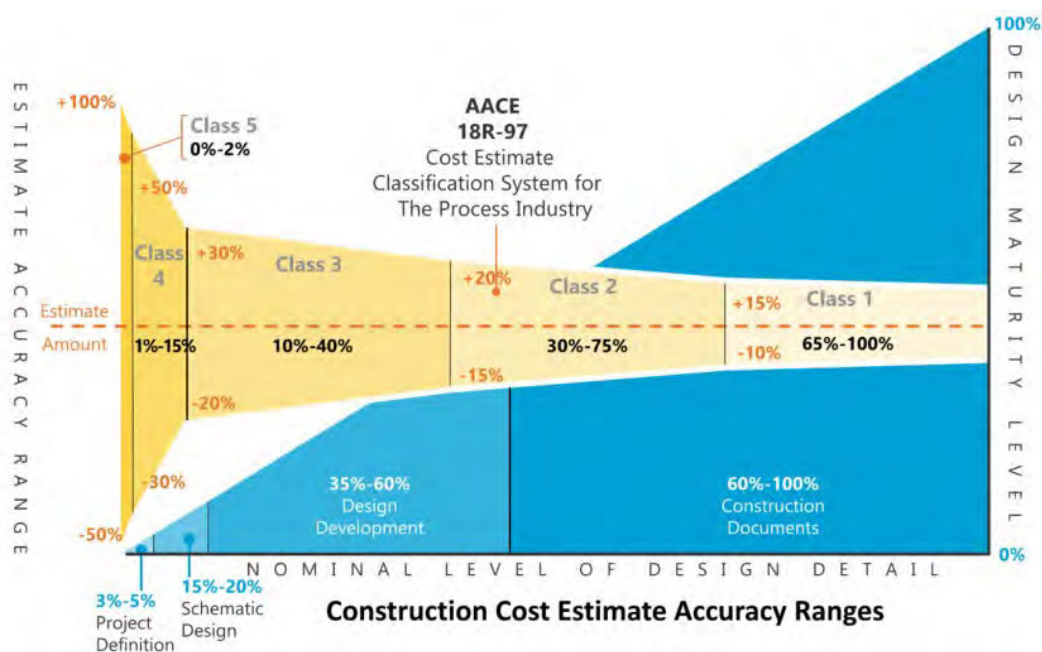


Figure 4-1. AACE Cost Estimate Classification Matrix for Process Industries

The capital costs from the Class 4 cost estimate were separated into the four potential project phases in Table 4-1. The costs in this table add 24 percent ELA to the construction cost, but do not include the 14 percent Gresham administration fee. For site-wide items in the estimate such as "Site Civil" and "Site Electrical," the costs were divided evenly and allocated per project line item in Table 4-1 (reference the Summary Report in Appendix A of the Class 4 Cost Estimate).

Table 4-1. Cost Estimate Breakdown by Phase

Item	Mean Cost Estimate (Class 4 Project Cost [+50%/-30% accuracy])
Phase 1 Project	\$16,370,000
Digester 3 Control Building/Dewatering Feed Tanks	\$ 7,800,000
New Thermophilic Digester	\$ 8,570,000
Phase 2 Project	\$12,240,000
Existing Digester Control Building Upgrades	\$ 3,320,000
Existing Digester Upgrades	\$ 7,730,000
Gas Holder	\$ 1,190,000
Phase 3 Project	\$10,220,000
FOG Receiving Station	\$ 1,060,000
FWS Receiving Station	\$ 1,970,000
Biosolids Storage	\$ 7,190,000
Phase 4 Project	\$27,750,000
Cogeneration	\$10,310,000
Biogas Conditioning	\$ 5,430,000
RNG Treatment	\$12,010,000
Total Program	\$66,580,000 ^{a, b}

^aThe accuracy range for a cost estimate at this level is -30% to +50%, which is a range of \$47 to \$100 million.

^bSite-wide work per phase was divided evenly to each line item: Site Civil, Yard Piping, Site Electrical, OR CAT Tax.

The business case evaluation that was completed as part of the alternatives evaluation and included in Appendix A-4 was updated with the capital cost for hybrid Option 3a from the Class 4 cost estimate. Table 4-2 summarizes the capital costs, annual operating costs, annual revenue, and the payback for the three scenarios: RE, RNG, and hybrid. Table 4-3 includes the payback periods for Option 3a with the proposed EPA Renewable Fuel Standard Program (RFS) updates that create a more favorable credit revenue market, and the impact of potential grant funding on the payback scenarios.

Table 4-2. Updated Cashflow Breakdown of Most Promising Revenue Generating Sub-options

Scenario	Assumptions	Total Capital Costs (\$M)	Total Credits/ Grants (\$M)	Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Payback
Baseline: New Mesophilic Digester	No additional FOG/food slurry	(\$32.4)	\$0	(\$1.8)	\$0	\$0.4	--
Option 1a: Renewable Electricity Commodity Value + Incentives	Moderate revenue from incentives; nominal value for OR CFP credits and eRINs	(\$55.2)	\$0	(\$2.5)	(\$0.7)	\$2.8	10 years
Option 2a: RNG Commodity Value + Incentives	Moderate revenue from incentives	(\$61.7)	\$0	(\$3.8)	(\$2.0)	\$4.5	10 years
Option 3a: Hybrid (Baseload Cogen + Excess RNG to market incentives)	Moderate revenue from incentives	~(\$66.6)*	\$0	(\$2.4)	(\$0.6)	\$2.8	16 years

*Only Option 3a Capital Cost was updated per the Class 4 cost estimate information.

\$M = million dollars.

Table 4-3. Updated Business Case Evaluation Payback for Option 3a Hybrid

Includes proposed EPA RFS updates and potential grant funding

Option 3a Hybrid	Current Incentives	Possible Future Incentives (Proposed EPA RFS Updates)	Grant Funding
BCE Fall 2022*	12 years	10 years	No grants
Updated Project Cost Estimate - April 2023	16 years	13 years	No grants
Updated Project Cost Estimate - April 2023	9 years	7 years	Assumed grants (30% IRA + \$3 million)

*This information has been superseded with the Updated Project Cost Estimate runs that include the Class 4 cost estimate capital costs.

Predesign Report for the WWTP Anaerobic Digestion and Cogeneration Expansion Project

The results indicate that the Option 3a hybrid offers a potential 7 to 16 year payback on a capital project that is both needed for capacity expansion and produces renewable energy and reduces FOG and food waste disposal in landfills.

5. Findings and Next Steps

The study has shown that it is beneficial for the City to continue exploring the feasibility of accepting additional liquid organic waste at the Gresham WWTP. Especially with the grant funding potential, there are payback options for a digestion and cogeneration expansion project that could serve to fulfill Gresham's capacity needs in addition to helping the community by accepting additional liquid organic waste in the region and producing renewable energy for the community.

The major findings in the predesign report are summarized as follows:

- The Hybrid option that includes both cogeneration and RNG capabilities offers the most flexibility, reliability, and built in redundancy for the digestion and cogeneration expansion project.
- There are project phasing options.
- A \$16 million third anaerobic digester capital project will be required and offers no potential payback.
- The hybrid option capital project includes the following and produces annual revenues:
 - Add a third thermophilic digester and convert the existing two mesophilic digesters to thermophilic
 - Expand FOG receiving and add FWS receiving
 - Add gas storage, expand gas cleaning and the boilers
 - Add digested sludge/dewatering feed tanks storage
 - Expand biosolids receiving infrastructure
 - Expand cogeneration system and convert excess biogas to electricity to sell in the California or Oregon clean fuels programs, and produce RNG (flexibility to do either)
- Similar to other successful energy projects like FOG receiving, this project could have a payback of less than 10 years if there is grant funding available and the renewable energy markets continue to become more favorable.
- Most sensitive components of the business case include the following:
 - Capital cost
 - Grant funding is important component of the business case evaluation
 - Incentives from renewable energy programs

Next steps are as follows:

- Explore and secure sources of funding for the project.
- Continue collaboration with Metro, Energy Trust, and Oregon Department of Energy.
- Decide on phasing and scope that will be included in the detailed design phase.
- Further evaluate industrial sources of liquid organic waste as a potentially viable future source.
- Collaborate with the City of Portland identifying sources of liquid organic waste in the Portland Metro Area.
- Continue discussion with PGE and DEQ to determine path forward with the Oregon Clean Fuels Program (CFP) and the California Low Carbon Fuel Standard (LCFS). Gresham intends to utilize the Oregon program assuming CFP rules are finalized and incentives are favorable/comparable to the LCFS.
- Continue to monitor changes to the EPA Renewable Fuel Standard Program (RFS).

Pre-design Report for the WWTP Anaerobic Digestion and Cogeneration Expansion Project

- Install piezometer at third digester location and gather groundwater elevation data to enable optimized design of digester geometry.
- Anticipated schedule:
 - Design complete in fiscal year (FY) 23/24.
 - Construction: FY 24/25 and FY 25/26
 - Project online, begin accepting additional liquid organic waste: 2026

6. References

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Appendix A

Alternatives Evaluation Documentation

A-1: High Strength Organic Material Market Assessment

A-2: Digestion Technology Update

A-3: Renewable Energy Update

A-4: Power Utility Coordination & Preliminary Economic Model Update

A-5: Capital Funding Assessment

High Strength Organic Material Market Assessment Technical Memorandum

Date:	September 8, 2022	Jacobs Engineering Inc.
Project name:	WWTP Anaerobic Digestion and Cogeneration Expansion Project – CIP WW00024	2020 SW Fourth Avenue, 3rd Floor
Attention:	Rob Chapler, Gresham Project Manager	Portland, Oregon 97201
Client:	City of Gresham	United States
Prepared by:	Massimo Romano, Jordan Norris, Lyndsey Lopez	T +1.503.235.5000
Reviewed by:	Matt Noesen	www.jacobs.com

Outline:

1. Introduction

The Gresham wastewater treatment plant (WWTP) has conducted this initial High Strength Organic Waste (HSOW) Market Assessment to provide an updated assessment of potential HSOWs that may be available to process in an expanded anaerobic digester facility and ultimately, generate more renewable energy. Under Task 2.3 – Feedstock Market and Pre-processing Approach Update of this project, this effort focused on contacting companies within Gresham’s Industrial Pretreatment Program (IPP) and was not intended to be a comprehensive review of all potential HSOW generators in the Portland metropolitan area. The potential HSOW streams that were considered as part of this market assessment include organic waste generated by bakeries, grocery stores, restaurants, and other food manufacturers.

Additional efforts will be discussed with the City and may be completed to aid in the data evaluation as the design progresses.

High Strength Organic Material Market Assessment

Jacobs consulted with the Gresham WWTP to determine a list of potential organic waste stakeholders in the area. IPP permittees were the focus of this effort and included the following companies:

- Teeny Foods
- Portland Specialty Baking
- Trailblazer Foods
- Eclair Farm
- Migration Brewing
- Townsend Farms
- Imperial Yeast

2. Stakeholder Survey Results

Despite reaching out to each of the businesses in the above lists, only Teeny Foods and Portland Specialty Baking provided information. Trailblazer food specified that they were not interested in responding to the questionnaire provided. Responses to the stakeholder questionnaire revealed that the HSOWs available were a combination of the grease trap interceptor contents and spoiled/inedible food. The following sections provide more information about the two stakeholders that provided information.

2.1 Portland Specialty Baking

Portland Specialty Baking (PSB) is a baking company that specializes in bagels, muffins, and specialty items. They are located in Portland and are approximately 20 miles (40 minutes) away from the Gresham WWTP. PSB uses a grease interceptor due to the oils and fats that are used when producing their baked goods. The other source of waste comes from spoiled goods or food and ingredients that fall on the ground or other unsanitary surfaces. Organic waste is already segregated from non-organic waste, making it simple to collect.

PSB currently contracts with River City Environmental (RCE) to collect and haul their grease interceptor waste. RCE hauls approximately 6,000 gallons of waste (water included) per month from PSB. This waste contains 3 to 5 inches of oil at the top of the container. Currently, PSB is paying RCE approximately \$2,400 per month for disposal of their grease interceptor waste. The cost is influenced by RCE needing to provide two trucks per disposal event.

PSB employs Feed Commodities to pick up their food waste and haul it to a facility where it is processed into animal feed. PSB pays to have food waste hauled to the Feed Commodities facility. Feed Commodities pays PSB per ton of food waste based on the price of corn on the Chicago Board of Trade. This usually results in PSB making a net profit from food waste so it is unlikely that PSB would divert food waste disposal from Feed Commodities unless the Gresham WWTP could match Feed Commodities' rate.

PSB also produces high biological oxygen demand (BOD) liquids that pass through the grease interceptor. This waste goes directly to the city and is likely already going (at least partially) to the WWTP.

2.2 Teeny Foods

Teeny Foods (TF) is a baking company that specializes in filled sticks, filled bites, filled handhelds, and fillings. They are located in Portland and are approximately 20 miles (40 minutes) away from the Gresham WWTP. TF uses a grease interceptor due to the oils and fats that are used when producing their baked goods. The other source of waste comes from spoiled goods or food and ingredients that fall on the ground or other unsanitary surfaces. Organic waste is already segregated from non-organic waste, making it simple to collect.

TF currently contracts with RCE to collect and haul their grease interceptor waste. RCE hauls approximately 6,000 gallons of segregated grease (water included) every two months from TF. This waste is composed of approximately 5,000 gallons from the interceptor plus 1,000 gallons of rinse down water. Currently, TF is paying RCE approximately \$2,400 per haul for the disposal of their waste, which averages out to approximately \$1,200 per month. TF may replace RCE due to their inability to provide necessary documentation in a timely manner.

TF employs Feed Commodities to pick up their food waste and haul it to a facility where it is processed into animal feed. TF pays to have food waste hauled to the Feed Commodities facility. Feed Commodities pays TF per ton of food waste based on the price of corn on the Chicago Board of Trade. TF usually makes a net profit from Feed Commodities. TF did express interest in working with the Gresham WWTP if it is economically feasible for them and environmentally helpful.

TF also produces high BOD (3000-4000 mg/L) liquids that pass through the grease interceptor. However, this waste goes directly to the city and is likely already going (at least partially) to the WWTP. All other waste reported (e.g. cardboard, plastic, etc.) is not of interest to the Gresham WWTP.

2.3 Migration Brewing

Despite not responding to the questionnaire, Migration Brewing (MB) was chosen as a potential HSOW producer as they had a 12-month average BOD of 4,240 mg/L. In order to provide an estimate of their average daily flow, information from another brewery in Clatsop County, OR was used. The other brewery produced 19,000 barrels per year and had four million gallons per year of process water. Knowing that Migration Brewing produces 10,000 barrels/year it was possible to assume that they had 2.1 million gallons per year of process water. (Jacobs 2022)

MB is a company that produces beer but also serves food. Most of their HSOW's are likely to be caught by a grease interceptor and the liquid that goes through it likely already goes (at least partially) to the Gresham WWTP. The means by which MB disposes of other waste is currently unknown.

3. Potential BOD Loading for Digestion

The City provided the list of IPP permittees and the 12-month ADF and 12-month average BOD for these permittees. A subset of this information, showing Teeny Foods, Trailblazer foods, and Migration Brewing, is shown in Table 3-1. Those 3 companies were deemed to have sufficient BOD for digestion. The 12-month average BOD level required for inclusion in this summary was 3,000 mg/L or more. Table 3-1 presents the daily BOD loading in pounds (lbs/d) by the generating company.

Table 3-1. Summary of BOD Loading by Company's Responding			
Company	12-mo. Avg ADF (MGD)	12-mo avg BOD (mg/L)	Mass of BOD loading(lbs./d)
Teeny Foods	0.0166	3,460	479
Trailblazer Foods	0.0202	3,030	510
Migration Brewing	0.005753*	4,240	203
Total Potential Waste			1,192

Table 3-1. Summary of BOD Loading by Company's Responding

Company	12-mo. Avg ADF (MGD)	12-mo avg BOD (mg/L)	Mass of BOD loading(lbs./d)
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12-month average ADF and BOD were provided by the City

Notes:

* Used information from another brewery in Clatsop County, OR to estimate the flow of Migration Brewing. The other brewery produced 19,000 barrels per year and had four million gallons per year of process water. Knowing that Migration Brewing produces 10,000 barrels/year it was possible to assume that they had 2.1 million gallons per year of process water. (Jacobs 2022)

ADF: Average Daily Flow

BOD: Biological Oxygen Demand

mg/L: milligrams per liter

lbs./d: pounds per day

12-mo: Twelve month

MGD: million gallons per day

4. Summary

While this study did reveal some information about the HSOWs in the area there were some important limitations. The first limitation was a lack of responsiveness from the business which resulted in PSB and TF being the only two willing responders, while Trailblazer Foods was not interested. Migration Brewing was unresponsive, but due to other available information, estimates about their BOD loading was available.

It is important to note that this study was not a comprehensive effort and was not intended to reach out to all entities with possible HSOWs in the region. This effort was focused on specific potential HSOW producers identified in the Gresham IPP. Of that subset, there was a limited response meaning that definitive conclusions are not currently possible. The next step is to discuss with the City some other potential strategies to reach out to current and future stakeholders in the region.

From this study, it appears that PSB is currently not interested in changing who they work with, while TF could be convinced if economically feasible. Another important finding is that some of the waste is likely already going to the Gresham WWTP, either through the sanitary sewer or via the current FOG receiving program. In terms of potential BOD loading for co-digestion that could be diverted or hauled to the Gresham WWTP, approximately 1,200 pounds per day of waste was identified.

5. References

City of Gresham. 2022. *Industrial Pre-treatment Program Permittees table*.

Jacobs. 2022. *High Strength Organic Material Market Assessment Technical Memorandum*.

Outfall Diffuser One Dimensional Hydraulic Analysis
Technical Memorandum

Portland Specialty Baking. "Home". *Portland Specialty Baking*, [Home | Portland Specialty Baking Co. \(pdxbaking.com\)](http://pdxbaking.com)

Attachment 1
Market Assessment Questionnaire
Forms

Subject: High Strength Waste Stakeholder Questionnaire

Project Name: Increasing Renewable Energy Production at Gresham WWTP

Prepared For: City of Gresham

Prepared By: Jordan Norris / Jacobs

Matt Noesen / Jacobs

Lyndsey Lopez / Jacobs

Date: July 6, 2022

Jacobs is performing a High Strength Waste Feedstock study to assist City of Gresham with potential plans to generate more renewable energy (either renewable electricity or renewable natural gas (RNG)). The purpose of the study is to identify additional sources of organic waste in the region. We would like to understand the quantities and types of high strength organic waste that you generate and how those wastes are being processed, if applicable.

Please let us know if you would prefer for your responses to be kept confidential.

Please keep responses confidential: Yes_____

If you prefer to talk to someone on the phone or via email, please contact Jordan Norris at:

Jordan.Norris@Jacobs.com or 916-886-1765

Name of interviewee, title: _____

Email or phone for best follow-up contact: _____

Name of business: _____

Owner: _____

6. Part I

1. Does your facility currently generate any organic waste streams? (Note: we are particularly interested in liquid (or wet solids) organic waste streams that are high strength (high in chemical oxygen demand (COD))
 - a. If no, you can disregard the remainder of the survey
 - b. If yes, please describe your feedstock (all organics streams) as detailed as you can (Example - food scraps from a grocery store, fats oils grease from a restaurant, organic waste from food processor, etc.)

2. Quantity (volume per day, per week, per year, etc.)
3. What time of year and how consistent is the feedstock (does the quantity or quality change throughout the year or with the seasons)?
4. Where is the feedstock currently disposed of (name/type/location of disposal or reuse practices)? What is the cost to handle the material now? (a range is fine) Would you consider sending it to another location if it was economically feasible and/or if it were more environmentally sustainable?
5. Does your facility have a grease trap or interceptor? What size? How many?
 - a. If so, who cleans it out, how often, and where does the material go?
6. Please rank from most important (1) to least important (5) the following five potential barriers that prevent organic waste from being collected separately from other waste and sent for donation, recycling, composting or other beneficial end uses. Please rank **all** items.
 - Cost, logistics (physical limitations to sorting)
 - Lack of knowledge regarding service providers
 - Not a priority for our business
 - Legal or contract requirements
 - Cleanliness and housekeeping issues or concerns
7. Please select from the list below the category that most closely describes your business.

3-Digit NAICS Code

112 - Animal production and aquaculture
213 - Support activities for mining, and oil and gas extraction
311 - Food manufacturing
312 - Beverage and tobacco product manufacturing
411 - Farm product merchant wholesalers
413 - Food, beverage and tobacco merchant wholesalers
445 - Food and beverage stores
452 - General merchandise stores
541 - Professional, scientific and technical services
611 - Educational services
622 – Hospitals
623 - Nursing and residential care facilities
624 - Social assistance
711 - Performing arts, spectator sports and related industries
721 - Accommodation services
722 - Food services and drinking places
812 - Personal and laundry services
Other

8. Anything else you would like to share about your feedstock you feel is of interest to the City of Gresham regarding waste management (e.g., expansion plans whereby high strength waste generation may increase in future)?

7. Part II (optional – answer what you are able to)

- **Contaminants:** Please share anything you know about contaminants in your feedstock, be as specific as you can on quantity and what the contaminants are.
- **Characteristics:** Please share any information you have regarding feedstock total solids, solids concentration, volatile solids (VS), chemical oxygen demand (COD), biological oxygen demand (BOD), pH, metals, salts/TDS, etc.

- **Other Questions**

9. Please estimate what percentage of the total amount of waste you throw away is made up of food waste, yard waste or fats/oil/grease?

10. If you reported food waste, how much food waste is potentially edible?

11. If you dispose of edible food waste, please rank from most important (1) to least important (5) the following five potential barriers that prevent food waste from being donated. Please rank **all** items.

- Time
- Logistics
- Liability concerns
- Not a priority for our business
- Lack of knowledge about where to donate food

12. When managing your organic waste, it is:

- Mixed with other waste for disposal
- For some, separated and collected separately from other solid waste for composting and/or donation
- For most, separated and collected separately from other solid waste for composting and/or donation

13. Is it possible to segregate this organic waste so it can be collected and handled separately? (choices include: Yes, Most but not all, Some of it, Very little of it, No)

14. What is the main collection method used currently to dispose of the following organic materials your company creates (Yard Waste, Preconsumer Food Waste, Postconsumer Food Waste, Food Processing Waste (indicate type, e.g. Brewery Waste, Fish Processing), Fats oils and grease, animal manure, other)? Please indicate N/A for items you do not produce.

15. For each type of organic waste your company disposes of, please estimate the annual all-in cost (collection and management)

16. Approximately how much non-organic waste (packaging or paper, plastic, metal, glass) is typically mixed in with the source-separated organic material?

17. When invoiced for waste collection, you pay: per pickup, per cubic yard, per ton, per gallon, etc.?

18. A typical bin size for your operation in cubic yards is (2, 4, 6, 8, even larger, don't know)?

Thank you for your time! If you have questions or would like to contact Jacobs, feel free to call or email
Jordan Norris.

Task 2.4 – Digestion Technology Update

Date:	March 10, 2023	
Project name:	Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project	2020 SW Fourth Avenue 3rd Floor Portland, OR 97201 United States T +1.503.235.5000
Attention:	Rob Chapler	
Client:	City of Gresham	
Prepared by:	Corey Klibert and Yash Chaudhary	
Reviewed by:	Matt Noesen and Kristen Jackson	

Outline

1. Introduction
2. Upgrading of Existing Digestion Tanks to Thermophilic
3. Digestion Configuration Alternatives Evaluation
4. Microbial Hydrolysis (MHP) Evaluation
5. Micro-aeration Evaluation
6. Summary and Conclusions

Acronyms and Abbreviations

BCE	business case evaluation
CFSTR	continuous flow stirred tank reactor
CHP	combined heat and power
FOG	fats, oils, and greases
FWS	food waste slurry
HSOW	high strength organic waste
kw	kilowatt
LMM	linear motion mixer
MHP	microbial hydrolysis
PS	primary sludge
RE	renewable electricity
RNG	renewable natural gas
TS	total solids
WAS	waste activated sludge
WWTP	wastewater treatment plant

1. Introduction

The City of Gresham, OR (City) Wastewater Treatment Plant (WWTP) has two, 1-million gallon mesophilic digesters (95 to 105 degrees Fahrenheit (°F)) that are operated in series. Primary sludge and secondary sludge (waste activated sludge) generated by the liquids treatment (both Upper Plant and Lower Plant) and fats, oils and greases (FOG) that are received from truck haulers are sent to the digesters, where sludge is broken down by microorganisms to produce biogas and Class B stabilized residuals per the EPA's 503 regulations. Currently, the biogas is converted into electricity and heat using two 400 kilowatts (kW) combined heat and power (CHP) cogeneration engines. The electricity generated from these engines is used for on-site power along with electricity that is purchased from a third party that operates a solar photovoltaic array located at the WWTP. These two renewable sources of power have allowed the City to achieve energy net zero status within the WWTP fence line. Any excess electricity is fed into the Portland General Electric (PGE) electrical grid and is regulated by a net metering agreement. However, the City is not paid for the electricity fed back into the grid. Waste heat from the engines is recovered and utilized on site for heating the digesters as well as several building spaces.

The City completed the Feasibility Study of Expanding Liquid Organic Digestion Capacity, CIP 322100 (Jacobs, 2020) to determine if it should accept additional FOG and potentially food waste slurry (FWS) that will be diverted from landfills through the Metro Commercial Food Scraps Policy. The study indicated the existing digesters were at capacity and could not accept any more additional organic waste loading. However, with the expansion of the digestion capacity the WWTP could process an additional 30,000 pounds volatile solids per day (lb VS/day) of additional high strength organic waste loading. This would allow the City go beyond net zero energy usage and generate revenue through either renewable electricity (RE) or renewable natural gas (RNG). The detailed business case evaluation (BCE) carried out in the feasibility study (Jacobs, 2020) focused on RE. At the time, RNG was excluded due to the relatively high capital costs and relatively low revenue potential.

This memorandum involves an assessment of the existing digestion tanks' ability to operate over the long-term at thermophilic temperatures. The assessment will outline upgrades and/or improvements to insulation or other mitigation measures that are needed to mitigate long-term impacts to the structures such as cracking that may result from operating at higher thermophilic digestion temperatures.

This task also involves qualitatively evaluating different digestion technologies and configurations and selecting the general approach that will be carried forward into the preliminary design. For example, analysis will include capacity considerations for a single, continuous flow stirred tank reactor (CFSTR), a series of CFSTRs that will approach plug flow, and/or a plug flow reactor configuration. Part of the analysis will be to determine if one of the design criterion will be to attain Class A biosolids through digestion.

Included in this task is an evaluation of microbial hydrolysis based on lab-scale pilot results in the Gresham laboratory. Also included is an economic evaluation considering costs to construct and operate the microbial hydrolysis system, changes to the heat balance, and if appropriate, increase/decrease in dewatering costs, decrease in cake storage costs (initial capital costs), reduction in biosolids land application costs.

Finally, part of this task is a desktop evaluation of micro-aeration in the digesters for reduction of hydrogen sulfide in the biogas prior to the biogas treatment systems. This evaluation will be based on information from other facilities and will not involve conducting a site specific pilot of micro-aeration, although a potential recommendation of this evaluation may be to conduct a pilot at the Gresham WWTP which could entail a lab scale testing utilizing the digestion pilot system or a full-scale pilot as part of the next phase of this project.

1.1 Flows and Loads Projection

Table 1 shows the updated projections for digester loadings from both wastewater solids and high strength organic waste loadings (FOG and FWS). The flows and loads were first developed in Feasibility Study of Expanding Liquid Organic Digestion Capacity, CIP 322100 (Jacobs 2020) using the data provided by the City and 2017 Master Plan. At part of this task, the flows and loads were revised and projected for a 5-year period starting from 2027 to 2047. Since the 2017 Master Plan only included year 2025, 2030 and 2036, the dry season maximum month BOD loadings were extrapolated for this analysis. Dry season maximum month typically has the highest BOD loading to the WWTP and therefore more WWTP solids loading to the digesters. The WWTP solids loading projections was estimated by multiplying the historical WW solids loading to BOD ratio (approximately 1.03) with the projected BOD loading for the 20-year.

The VS/TS ratio of 82 percent from the previous study was assumed in this analysis. The WWTP is installing new rotary drum thickeners which would increase the digester feed solids to 5-7 percent total solids (TS). For the purpose of this study, it was assumed that the primary sludge and waste activated sludge (WAS) from the upper plant and lower plant would be co-thickened by 2027. The thickness of the blended sludge stream is estimated to be 5.5 percent in this study. Existing FOG loadings are based on the historical data obtained in the previous evaluation. Similarly, the additional FOG loading was determined in the 2020 study and the same quantities are assumed in this analysis with additional deliveries occurring from 2027. FWS is anticipated to be received at the WWTP between 2027 and 2032. For this study, FWS is assumed to be received from 2032. All subsequent capacity assessments in this memorandum are based on the anticipated digester loadings listed below.

Table 1. Anticipated Digester Loadings

	Units	2027			2032			2037			2042			2047		
		AA	P30d	P14d	AA	P30d	P14d	AA	P30d	P14d	AA	P30d	P14d	AA	P30d	P14d
WW Solids Load	lb TS/day	34,100	41,000	41,800	36,000	43,300	44,100	37,900	45,600	46,400	39,800	47,900	48,700	41,600	50,200	51,000
WW Solids VS/TS Ratio	%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%
WW Solids Volatile Loading	lb VS/day	27,938	33,658	34,239	29,492	35,529	36,143	31,045	37,401	38,047	32,599	39,273	39,951	34,152	41,144	41,854
Digester Feed WW Solids	% TS	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
WW Solids Flow to Digesters	gpd	74,277	89,484	91,028	78,407	94,460	96,090	82,537	99,435	101,152	86,668	104,411	106,214	90,798	109,387	111,275
Current FOG Solids Volatile Loading	lb VS/day	8,700	11,300	11,400	8,700	11,200	11,400	8,700	11,300	11,500	8,700	11,300	11,500	8,700	11,300	11,500
Current FOG Solids Flow to Digesters	gpd	11,600	13,900	14,700	11,600	13,900	14,700	11,600	13,900	14,700	11,600	13,900	14,700	11,600	13,900	14,700
Additional FOG Solids Volatile Loading	lb VS/day	10,000	10,836	10,446	10,000	10,836	10,446	10,000	10,836	10,446	10,000	10,836	10,446	10,000	10,836	10,446
FOG Solids Flow to Digesters	gpd	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400
FWS Volatile Loading	lb VS/day	0	0	0	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
FWS Solids Flow to Digester	gpd	0	0	0	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400

AA: Average Annual
P30d: Peak 30-Day
P14d: Peak 14-Day

2. Upgrading of Existing Digestion Tanks to Thermophilic

A structural model (Figure 1) was developed to assess the ability of the existing cast-in-place concrete digestion tanks to operate at the increased temperatures required for thermophilic digestion (130–135 °F). The higher operating temperatures create a larger temperature differential between the inside face and outside face of the concrete walls. This larger differential increases the internal stresses within the concrete wall. These stresses are resisted by the reinforcing steel. The analysis evaluates the capability of the reinforced concrete walls to resist the increased stresses and to stay within the stress limits required for crack-control of the concrete by ACI-350, Code Requirements for Environmental Engineering Concrete Structures.

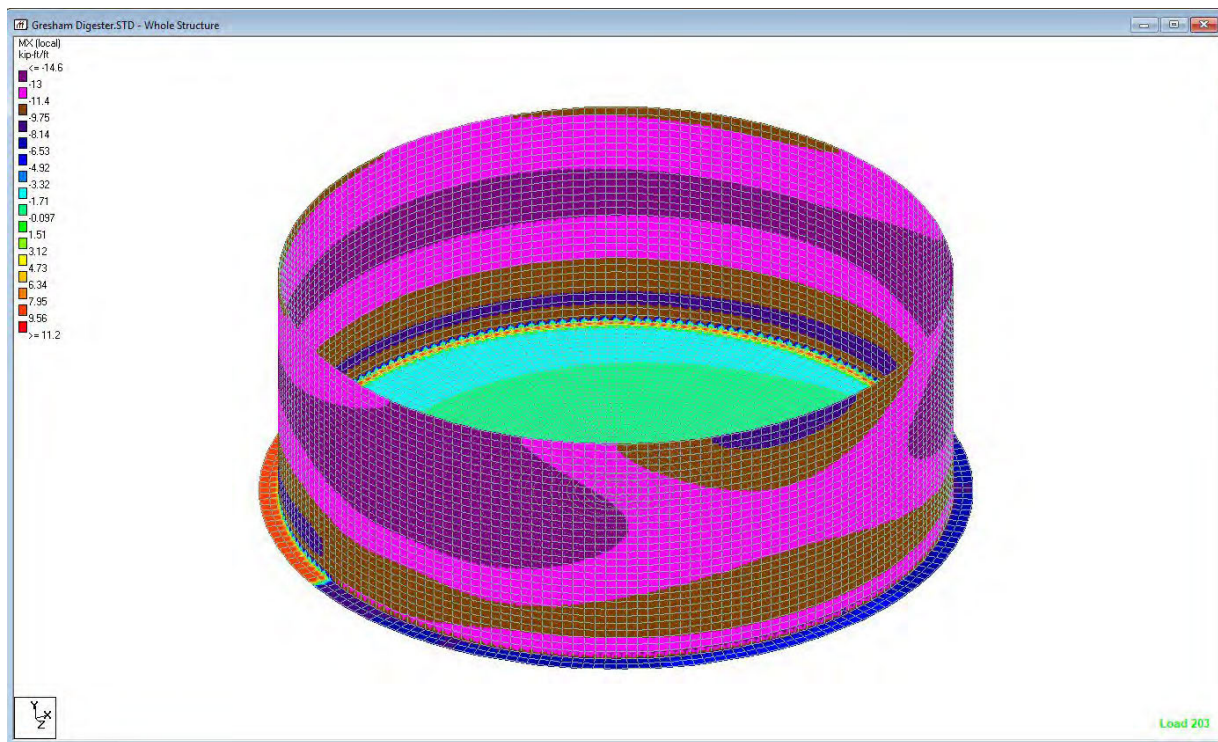


Figure 1. Finite Element Analysis of Existing Gresham Digester

The analysis determined that the existing concrete walls could accommodate these higher operating temperatures without requiring any supplemental reinforcing. It was further determined that no additional insulation would be required to limit the stress increases and mitigate long-term impacts to the existing structures.

3. Digestion Alternatives Evaluations

This subtask involves qualitatively evaluating different digestion technologies and configurations and selecting the alternative that will be carried forward to the predesign report. An alternative shape (silo) is considered for the geometry of the new digester, and the following process flow configurations are also evaluated: one single, continuous flow stirred tank reactor (CFSTR), a series of CFSTRs that will approach plug flow, or a plug flow reactor configuration. Part of this analysis will be to determine if one of the design criterion will be to attain Class A biosolids through digestion.

Two of the key technical objectives of this predesign are to more clearly define the digestion process schematic and develop a preliminary heat balance. In order to achieve these objectives the following items will be defined:

- Sludge heating and heat recovery: integrating the heating system for the higher temperature, thermophilic digestion with heat recovery from the cogeneration system cost-effectively optimizes heat recovery from digested biosolids while reducing the overall heat demand.
- Sludge feeding and withdrawal: providing flexibility in feeding the existing digesters and the new digester with attention to even distribution; sludge withdrawal removing foam and floatables from the surface and grit from the bottom of the digesters.
- Digester mixing: digester mixing system selection includes comparing the highly successful use of linear motion mixers to a pump mixing approach, with the goal to provide adequate mixing, avoid grit deposition, and prevent short-circuiting between the feed and withdrawal.
- Digester cover: this involves selection of an appropriate digester cover for the new thermophilic digester.
- Digester coating: the digester lining for the new digester and coating for the original digesters must be compatible with thermophilic operating temperatures.
- Sludge characteristics: evaluating sludge, FOG, and FWS characteristics to determine the need for additional sludge conditioning.
- Digester gas: the gas system must be able to manage additional, higher temperature gas associated with thermophilic operation; micro-aeration to reduce hydrogen sulfide can supplement and reduce the operating costs of the H₂S removal gas treatment system.
- Instrumentation and Control: each system element requires adequate instruments and control for safe and reliable operation, including startup and commissioning.

3.1 Digester 3 Design

3.1.1 Size and Geometry of Third Digester

The digester geometry is the most important factor affecting the selection and design of the critical elements of the digester. It governs the design and ultimately the effective operational management of historically problematic portions of the digester:

- the surface – where low-specific gravity material (scum) accumulates
- the bottom—where high-specific gravity material (grit) accumulates

Modern digesters diverge considerably from the conventional pancake design in managing these problematic areas. Conventional pancake digesters feature shallow sloped bottoms and relatively low height-to-diameter ratios. The pancake digester is typically less expensive to construct but exhibits greater rates of grit deposition due to the flatter slope of its cone. Even with highly energetic mixing systems, the pancake digester generally will have low energy areas of mixing intensity, commonly called “dead zones,” where there is inadequate mixing intensity to suspend the grit.

There are notable disadvantages with a pancake digester. The mixing intensity required to suspend grit to the surface has been shown to far exceed that which is necessary to drive the biological process. The mixing systems of pancake digesters either tend to be relatively oversized and inefficient (from a process standpoint) or else are undersized and ineffective at managing grit buildup in the digester. Their shorter aspect ratios limit the degree of natural mixing from biogas evolution that is translated to the bulk fluid, further increasing the required size of their mixing systems. And lastly, they are more susceptible to

experiencing volume expansion events than silo digesters with steep cone bottoms. A silo digester has a 1:1 height-to-diameter ratio and a steeper cone which helps to facilitate improved grit removal. Scum and foam can accumulate at the top, but it is better managed due to a smaller surface area of the silo digester. Rapid volume expansion events (due to loss of mixing or feed changes) are less pronounced in silo digester due to greater pressures keeping biogas in suspension for more of the liquid column. This keeps sludge density and thus foaming at a reduced level.

Note that relatively new pump mixing systems attempt to create an energy vortex at the bottom of the digester so that grit will migrate and accumulate at the center of the digester. These systems are typically designed with bottom withdrawal of grit-laden sludge. These systems have been shown to minimize the dead zones of a pancake digester. Complementary approaches to bottom grit control systems, such as a hydraulic jet mixing, includes gentle bulk fluid systems, such as linear motion mixers, and surface agitation and wasting systems.

Three different digester geometries were evaluated for the third digester. The geometry for the new digester can be either a pancake shape similar to existing digesters (low height to diameter ratio), a silo type (equal height to diameter), or a hybrid of the two. The pancake digester would have the largest footprint which is currently shown on the drawings. A silo type digester would reduce the footprint and would be much taller than the existing digesters. While a silo digester offers many operational benefits, there are some practical limitations that need to be considered. A third, hybrid option was considered to address these site limitations while still providing the benefits of the silo geometry.

The groundwater level is a constraint for how deep a digester should be constructed. It is undesirable to have the bottom of a digester extend below the groundwater level because this condition creates a heat-sink effect. This cools the digester, requiring more energy usage to keep the digester at its optimum operating temperature. A silo digester can be constructed above the groundwater level but this pushes the profile further out of the ground and makes the digester taller, and therefore more expensive to construct. The groundwater levels shown in Figure 2 were extrapolated from the 1997 geotechnical report (Fujitani Hiltz and Associates, 1997). It is recommended to install a boring with a groundwater monitor at the location of Digester 3 to allow collection of groundwater data to help determine the optimum depth of the new digester.

Another limitation with a silo digester is that the increase in sidewall depth will require the new thickened sludge pumps to pump against a higher static head than originally designed. Preliminary calculations show that the thickened sludge pumps could potentially be capable of pumping to a water surface elevation in the new digester up to 20 feet above the water surface level in the existing digesters. Thicker sludge behaves like a Bingham plastic, making pump calculations less accurate as sludge concentrations increase. It is recommended that these preliminary pump calculation models should be calibrated against actual thickened sludge pumping operational data in the design phase after the startup of the new rotary drum thickeners and thickened sludge pumps.

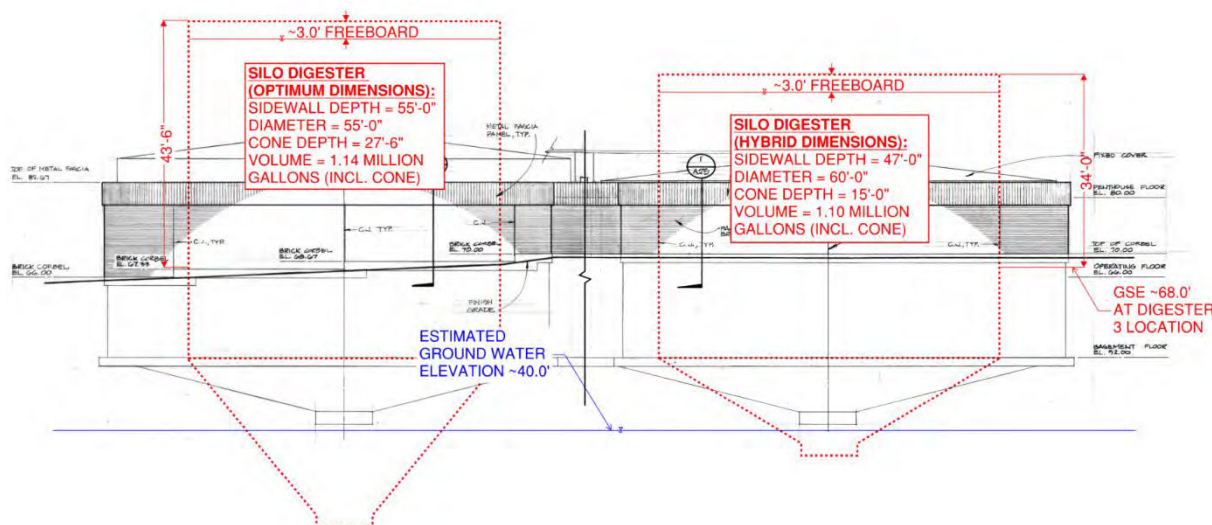
A hybrid geometry for Digester 3 is also evaluated that would still offer some of the operational benefits of a silo digester but would balance performance against these other practical limitations. The hybrid digester has a higher height-to-diameter ratio than a pancake digester. The hybrid geometry would allow for a slightly steeper cone to be set just above the groundwater elevation to optimize energy usage. It would also allow the water surface elevation to be set at a level that would still be within the operating range of the new thickened sludge pumps.

The preliminary design criteria for the different digester geometries for Digester 3 are presented in Table 2. The silo and hybrid digesters would be smaller in diameter but much taller than existing pancake digesters.

Table 2. Digester 3 Design Criteria

Parameter	Unit	Pancake Digester	Silo Digester	Hybrid Digester
Quantity	each	1	1	1
Inner diameter	feet	80	55	60
Sidewall height	feet	30	58	50
Side water depth	feet	27	55	47
Cone depth	feet	10	27.5	15
Height to diameter ratio	-	0.34	1	0.78
Cover type	-	Fixed carbon steel	Fixed carbon steel	Fixed carbon steel
Effective volume of digesters	million gallons	1.0	1.0	1.0
Operating temperature	°F	130–135	130–135	130–135

Figure 2 presents how the silo digester and hybrid digester presented in Table 2 would compare to the existing digesters at the WWTP.


Figure 2. Silo Digester and Hybrid Digester Geometry Compared Against Existing Pancake Digesters

Based on this evaluation is recommended that the City proceed to design with the hybrid digester geometry and follow-up with some additional groundwater monitoring so that assumptions for groundwater levels can be confirmed.

3.1.2 Mixing System

Linear motion mixers (LMMs) by Ovivo have provided reliable mixing in the existing digesters while consuming much less energy relative to other viable options (namely pump mix and draft tubes). Linear motion mixers use an oscillating ring-shaped hydro-disk that moves up and down through the liquid to mix the digester. Linear motion mixers use an internal cam scotch-yoke design that efficiently transfers

energy from the drive motor to the liquid. Linear motion mixers have a low power demand and are easy to maintain.

The new digester will also use the linear motion mixer for mixing to optimize volatile solids reduction and has production. Accepting additional food waste is not expected to change the mixing performance of the digesters. If a pancake digester is selected, then a single hydro-disk will be sufficient to mix the contents of the digester. Linear motion mixers will be slightly different for a silo or hybrid digester. Since the digester sidewater depth is greater than a pancake digester, the shaft of the mixer would be longer as well as additional hydro-disks may be needed to ensure optimal mixing. The design for the mixing system will be completed after the geometry for the new digester is finalized.

Also, improvements to the existing LMMs will be incorporated into this project; see section 3.2 Conversion of Existing Digesters to Thermophilic for additional information on those improvements.

3.1.3 Other Design Features of Digester 3

Digested sludge heat exchangers are required to heat sludge to thermophilic temperatures and maintain digester temperatures due to heat loss through the shell. The heat exchangers will use sludge recirculation and hot water recirculation to maintain the digester contents within the required temperature range. Solids will be withdrawn directly from the tank where sludge circulation pumps will convey the solids through a heat exchanger before the solids are returned to the digester. This configuration creates a closed recirculation loop and allows better control over digester temperature compared to heating the influent sludge directly.

The new digester could be configured to allow withdrawal from both the liquid surface or bottom of the cone. Surface overflow will limit foam and scum buildup in the gas dome. The sloped floor bottom (cone withdrawal) will facilitate the transfer of grit and debris through the digestion process. Withdrawal from the surface overflow would provide scum and foam management. During surface overflow operation, feed sludge will displace liquid in the operating digesters. A gravity overflow line will discharge to a digester standpipe. As digested solids reach the elevation of this pipe, it will overflow into the standpipe located adjacent to the digester. This design feature controls the digester normal liquid level. The standpipe will be a 36-inch-diameter, 316L stainless steel pipe that stands vertically adjacent to the digester. Digested solids will be pumped out of the standpipe by the digester withdrawal pumps. During cone withdrawal operation, speed control of the digested sludge pumps will match the pumped withdrawal rate to the measured flow entering the digesters. Alternatively, the pumps could be operated in level control mode based on the level in the digester. The digester withdrawal pumps will run on variable speed drives.

The sludge withdrawn from the digesters will be sent to the dewatering feed tank to recover heat. This will be used to pre-heat the thickened feed sludge and then sent to the digestion process. There are two dewatering feed tanks working in tandem. Hot digested sludge from the tank that is receiving digested sludge will act as the suction for the sludge heat recovery pumps. These pumps will pump hot digested sludge through a rectangular sludge to sludge heat recovery heat exchanger. This heat exchanger will recover heat from digested sludge and transfer that heat to the thickened sludge feeding the digesters. The digested sludge outlet from the sludge heat recovery heat exchanger will be discharged to the opposite dewatering feed tank to aid in keeping the lead tank as hot as possible. Cooling digested sludge prior to dewatering is critical to avoid excessive odors at the dewatering facility. The two tanks are sized to provide sufficient storage volume to allow operational flexibility when the dewatering process is offline.

The new digester will be equipped with a fixed carbon steel cover. The cover will include sample ports, access manholes, and nitrogen gas feed connection. The nitrogen gas feed connection will allow the operators to backflush the headspace of the tank when taking it out of service or putting it back in service. Backflushing prevents the possibility of creating an explosive mixture of methane and oxygen during these events. Operating at thermophilic temperatures presents some concerns with coating systems. The coating system to be selected for the cover will be evaluated in the future design phases.

Digester gas produced will be collected in the headspace of the digester and routed to a low-pressure gas holder bubble. The gas storage will be used to buffer fluctuation in digester gas production and allow the downstream equipment to operate at near constant setpoint. A safety-selector valve and combination pressure/vacuum relief valves with flame arrestors will be mounted on the cover. These valves will regulate pressure in the digester to eliminate damage to the cover from digester over- and under-pressurization. The digester normal operating pressure, maximum pressure, pressure relief crack pressure, and vacuum relief crack pressure will be determined during detailed design. A separate vacuum relief valve, with no flame trap, will be provided as a last line of defense against vacuum conditions if the combination pressure relief/vacuum valve fails. The digester cover will be equipped with a weighted hatch to provide emergency pressure relief if the pressure relief and emergency overflow mechanisms fail.

Emergency overflow lines will be located on Digester 3. The digester overflow will be piped through a U-shaped trap with its vertical leg taller than the maximum operating pressure of the digester. The trap will be filled with water to provide a gas seal. This feature will prevent digester gas from escaping the tank.

3.2 Conversion of Existing Digesters to Thermophilic

The existing digesters at the WWTP will also be upgraded to operate at thermophilic temperatures. The covers for the existing digesters will be replaced with fixed carbon steel covers and insulated. The cover will include sample ports, access manholes and nitrogen gas connection, similar to Digester 3 cover. The new covers will include platforms to provide maintenance access to the mixers and other equipment. The existing linear motion mixers will be retrofitted to be able to operate at the thermophilic temperatures. Impacts to the hot water loop is discussed in the Predesign Report (Jacobs, 2023). Increase in operating temperatures for the existing digesters presents some concerns with the existing coating system. Further investigation of the existing coating system and applicable coating systems for thermophilic operations will be conducted in the future design phases.

Since the installation of the LMMs, Ovivo has introduced improvements to the scotch yoke cam drive lubrication system. The existing LMMs will be upgraded to include this upgrade so that the unit will be easier to maintain. Also, small platforms on the new digester covers will be installed to access the drives so that the use of ladders will not be required.

3.3 Operating Configuration

3.3.1 Series Configuration

Currently the digesters at Gresham are configured to operate in series, with a primary digester followed by a secondary digester. The new digester could be configured in the same manner, with Digester 3 followed by Digester 1 and then Digester 2. Figure 3 shows the series configuration of the digestion process at the WWTP.

For combined wastewater solids and high strength organic waste digestion at thermophilic temperatures, the maximum recommended VSLR is 0.3 lb VS/day-cf and the minimum SRT is 10 days. However, since all of the feed is sent to one digester, the VSLR would exceed this value resulting in increased digestion volume for the digester. The two remaining digesters would provide minimal additional digestion of the volatile solids. The new digester would need to be significantly bigger than the existing digesters to be able to accept all of the feed sludge and for the resulting system to have the same capacity as a system operated in a parallel configuration. Moreover, in this case, the existing digesters would then be oversized for their purposes as secondary digesters. This process configuration would result in high loading to the first reactor, followed by underloading of the secondary reactors.

Given the several drawbacks associated with a series configuration, this will not be considered further.

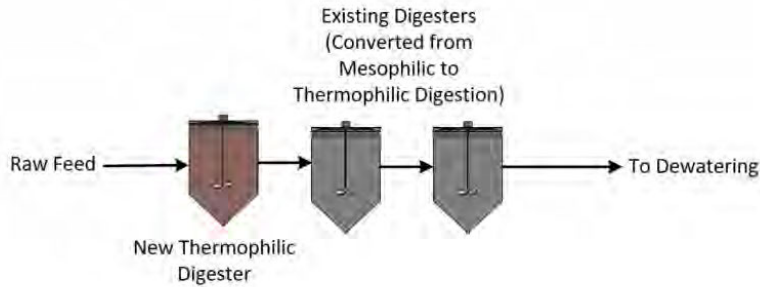


Figure 3 – Series Configuration of the Digestion System at the WWTP

3.3.2 Parallel Configuration

Operating digesters in a parallel configuration is the most commonly used configuration at treatment plants with multiple digesters. In this configuration, the raw sludge is fed at equal flowrates to the digesters. This configuration works best when all the digesters are operating either as all mesophilic or all thermophilic.

At the WWTP, Digester 3 will be constructed as a thermophilic digester. Existing mesophilic digesters will be converted to operate at thermophilic conditions. Figure 4 provides a simplified process flow diagram for the parallel configuration. The digesters will be configured to operate in parallel regardless of the number of digesters in service, but provisions are included to allow transfer between the digesters. The sludge feeding to the digesters will be modified to include automated valves on the feed pipes that will actuate the flows to the digesters based on a feed schedule. For instance, when operating all three digesters in parallel, the actuated valve would stay open to each digester for 20 minutes (60 minutes divided by three digesters). Then the cycle would repeat. Organic waste from the HSOW facility is configured to allow for parallel feeding to the digesters.

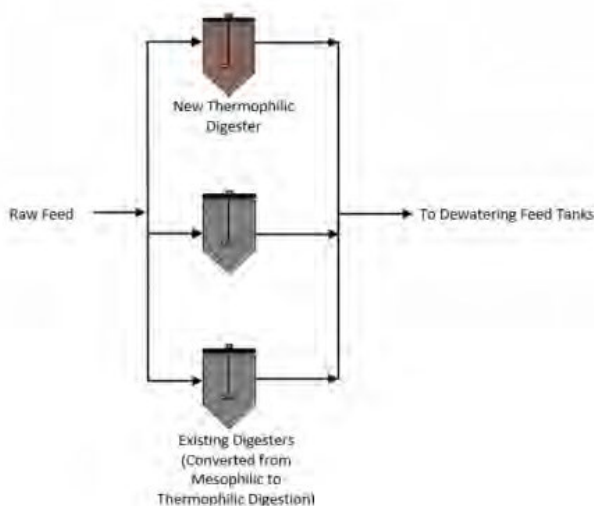


Figure 4: Simplified Process Flow Diagram for Parallel Configuration

This configuration has the best process performance with the higher volatile solids loading rate and destruction as well as improved reaction rates. This allows for the digesters to be smaller with lower SRTs. Additionally, the City is looking to accept additional high strength organic waste. The parallel configuration will provide the most operational flexibility. The BCE analysis indicated that two

thermophilic digesters will have sufficient capacity for the wastewater solid and high strength organic waste with one digester offline year-around. A drawback of thermophilic digesters is more odorous sludge due to higher concentrations of sulfur by-products. This is mitigated to some degree with sludge heat recovery, which cools the digested sludge, since lower temperature thermophilically digested sludge has lower odors than hotter sludge. This configuration does involve more piping and valving increasing capital expenditure, however. Additionally, micro-aeration of the digesters (evaluated in Section 5 below) reduces the generation of sulfurous compounds and may be considered as another way to offset the higher odor potential of thermophilic sludge.

It is recommended that the City select the parallel configuration due to the best process performance even with one digester offline and most operational flexibility. This configuration maximizes the capacity of the digesters by splitting the organic loading among three digesters and results in a smaller required volume for the new digester than other configurations.

3.3.3 Temperature Phased Anaerobic Digestion

Temperature phased anaerobic digestion (TPAD) incorporates both thermophilic and mesophilic digestion. Typically its operated as thermophilic-mesophilic but there have been several instances where mesophilic-thermophilic configuration as well. Thermophilic phase provides a faster digestion rate, allowing higher VSLRs and greater volatile solids loading destruction rates. The mesophilic phase will reduce the odorous compounds that are not destroyed in the thermophilic phase and provide stability of the entire process. Foaming in the digesters is reported to be reduced in a TPAD configuration.

Figure 5 shows the TPAD configuration at the WWTP. Digester 3 will serve at the thermophilic digester and existing digesters will continue to operate at mesophilic conditions. The raw feed sludge and high strength organic waste will be pumped to Digester 3 and then to Digester 1 and Digester 2. Digester 1 and Digester 2 will operate in a parallel configuration. Digester 1 and Digester 2 may be operated in series, but it is not recommended for the reasons stated in the previous sections.

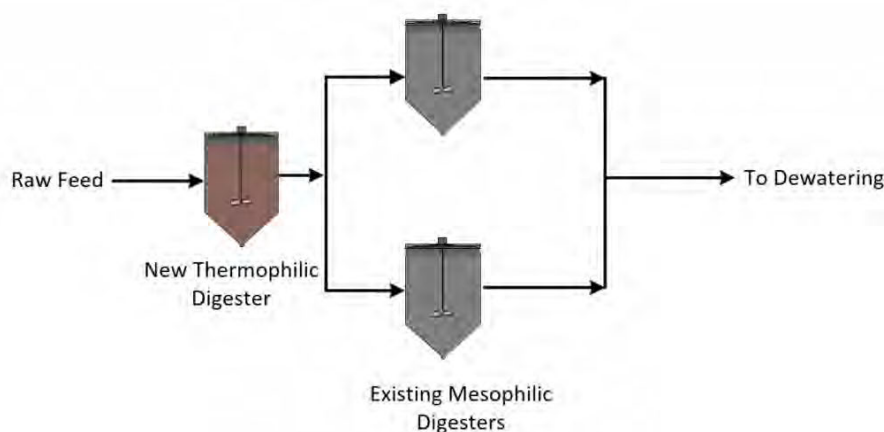


Figure 5: Simplified Process Flow Diagram for TPAD

One major drawback of TPAD, is when the thermophilic digester is offline. This would decrease the loadings rates to the mesophilic digesters. The existing mesophilic digesters do not have sufficient capacity to accept additional high strength organic waste. During the maintenance of Digester 3, the City would need to stop accepting additional high strength organic waste. This would impact revenue generation for the City.

Additionally, TPAD operation would reduce the capacity of the overall system if the new digester was sized to be equal to the existing digesters, since all feed would need to pass through a single digester rather than being split among three digesters. This would result in three times as much organic loading to the first-stage digester, which would reach its design maximum organic loading rate much sooner than in a

parallel configuration. To reach the same organic loading capacity of the parallel configuration, a new TPAD digester would need to be significantly larger than the existing digesters.

For these reasons, during the development of the BCE, it was found that selecting a TPAD configuration provided minimal cost benefit with deferred capital investment and resulted in a longer payback period. Furthermore, unless the new digester was sized to be significantly larger than the existing digesters, the resulting TPAD system would have less capacity than a parallel configuration. Therefore, TPAD configuration is not recommended for the WWTP.

3.4 Phasing Considerations

Construction of Digester 3 and other improvements at the WWTP will likely need to be completed through a phased sequence of separate projects. Digester 3 would be constructed in the first phase followed by the upgrades to the existing digesters. The existing digesters and control building must remain in continuous operation until the new digester and digester control building facilities are operational. The startup of the new digester and interconnections with the existing heating loop and sludge feed and withdrawal facilities must be coordinated.

Phase 2 of the project will include upgrades to the existing digesters. Before any construction activities can begin, the installation of the new gas storage facility will need to be completed prior to beginning any of the retrofits on the existing digesters. The floating cover in existing Digester 2 provides an operational buffer for storage of excess digester gas. Additionally, retrofits to the existing digesters must occur sequentially, leaving one of the existing digesters and its support equipment online while making improvements to the other existing digester. The existing boiler and heating recirculation pumps will need to remain in service until the new boiler(s) and heating water system are operational.

A detailed description of the construction constraints and project phasing is covered in the predesign report. A brief summary is as follows:

- Phase 1 - Construction a new thermophilic Digester and new Digester Control Building and then in the second phase convert the existing two digesters to thermophilic. In order to operate the digesters in parallel, automated valves will need to be installed in the yard on the thickened sludge piping, FOG piping and FWS piping to direct flows to the digesters. The Digester Control Building will house the sludge recirculation system and heating, digested sludge pumps, sludge heat recovery, hot water loop system and electrical equipment. The dewatering feed tanks are located west of the Digester Control Building.
- Phase 2- Construct a new gas storage facility prior to replacing the Digester 2 floating cover. The existing digesters will be upgraded to operate at thermophilic conditions in a sequential manner. The covers for both the digesters will be replaced with a fixed carbon steel cover.

3.5 Summary

The simplified process flow diagram of the selected digestion technology and configuration is shown in Figure 6. The new Digester 3 will be a thermophilic type. Existing digesters will be upgraded to operate at thermophilic temperatures. The digestion process will be operated in a parallel configuration to provide the best process benefits and provide the most operational flexibility. Other upgrades to existing facilities and new facilities shown in Figure 6 are described in the predesign report. The entire project will be phased to ensure minimal impacts to the operations of the WWTP.

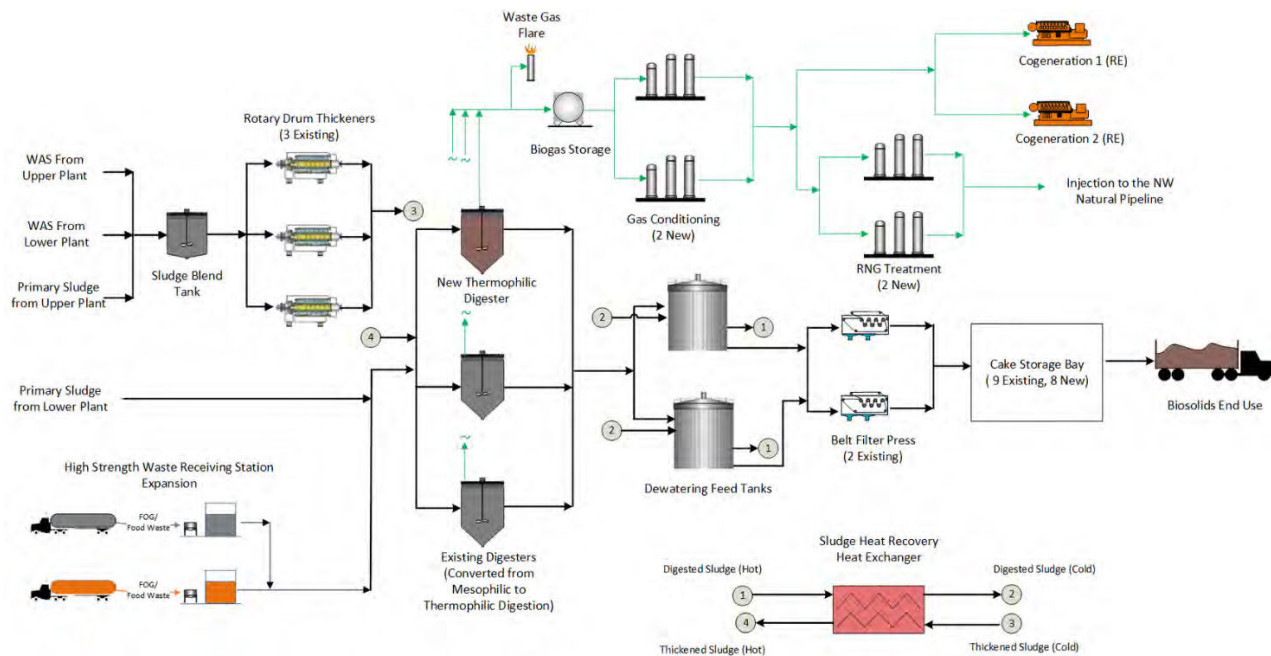


Figure 6: Simplified Process Flow Diagram for the Selected Alternate

4. Microbial Hydrolysis Process (MHP) Evaluation

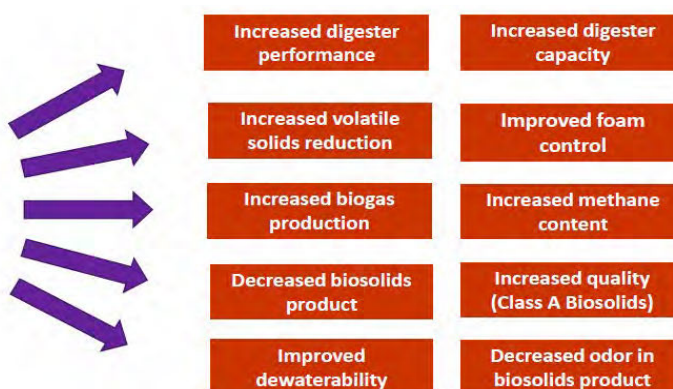
Jacobs conducted an evaluation of microbial hydrolysis process based on lab-scale pilot results in the Gresham laboratory. Jacobs conducted an economic evaluation considering costs to construct and operate the microbial hydrolysis system, changes to the heat balance, and if appropriate, increase/decrease in dewatering costs, decrease in cake storage costs (initial capital costs), reduction in biosolids land application costs.

4.1 Overview

Jacobs along with professors at the Brigham Young University has developed a new microbial hydrolysis process (MHP) using *Caldicellulosiruptor bescii* (*C. bescii*), a hyper-thermophilic bacterium, to enhance the performance of any anaerobic digestion process. The bacterium was isolated in a geothermally heated freshwater pool in Russia in 1990. *C. bescii* is capable of hydrolyzing cellulose and other poorly digesting recalcitrant biomass such as waste activated sludge, into volatile acids (e.g., acetic, lactic acids), that are then converted into biogas by methanogens. MHP is compatible with any anaerobic digestion process including mesophilic anaerobic digestion (MAD), thermophilic anaerobic digestion (TAD), temperature phased anaerobic digestion (TPAD) and thermal hydrolysis process (THP).

The benefits of MHP process are summarized in Figure 7. The risks associated with MHP include further refinement of the design criteria for a full-scale system and food slurry has not been tested in the MHP process.

Potential Benefits of the C. Bescii Hydrolysis Process (CBHP)



Key benefits are increased biogas production and decreased biosolids

Figure 7: Benefits of MHP system

4.2 Research Work

Initial research was carried out in 2020 and 2021 which was focused on improving anaerobic digestion performance by hydrolyzing and fermenting recalcitrant biomass, such as cellulose and waste-activated sludge, that was not digested initially in anaerobic digestion. Bench scale and laboratory scale testing was conducted at the Gresham Wastewater Treatment Plant (WWTP) in Portland, Oregon using BioProcess batch equipment for the bench scale testing and Anaero Technology continuous-feed anaerobic process equipment for the laboratory scale. Digested sludge from Encina Wastewater Authority WPCF was also tested using the bench scale testing at the WWTP. Pilot scale research was conducted at the Clinton River Water Resource Recovery Facility (WRRF) in Oakland County, Michigan, using a 52-foot pilot trailer containing process equipment customized for MHP research. The performance of the digesters from the bench scale testing and pilot testing are summarized in Table 3.

Table 3. Summary of Results from Lab-Scale and Pilot Scale Testing of MHP

Facility	Digestion	Existing Performance VSR	Method	Control Performance VSR	Test Performance VSR
Gresham WWTP Gresham, OR	Mesophilic AD with FOG	60%	Lab-scale	70% Attributed to C. bescii in control	80%
Encina Wastewater Authority WPCF Carlsbad, CA	Mesophilic AD	60%	Lab-scale	71% Attributed to long retention time	77%
Clinton River WRRF, operated by Oakland County WRC; Pontiac, MI	THP Mesophilic AD	58%	Pilot-scale	65% Attributed to solids settling in control	75%

4.3 Basis of Design

The MHP system is designed based on the operating parameters and performance results collected from the lab scale and pilot testing. This system will improve anaerobic digestion performance with increased

VSR, reduced biosolids production and increased biogas production. The major components of the MHP are:

- Hydrolysis Tanks
- Feed Pumps
- Heating System
- Mixing System (pumps and nozzles)

The design of these different components is based on the 2047 projected flows and loads of the future conditions. Figure 8 is a simplified process flow diagram of the MHP system at the WWTP. The existing solid processes at the WWTP consist of sludge co-thickening by rotary drum thickeners and pumped to the MHP hydrolysis tanks. Primary sludge from the lower plant will be pumped directly to these tanks. There are four tanks configured as three duty tanks and one standby tank. Each tank has an active volume of 130,000 gallons and is sized for 1 day retention time for the 2047 flows. An HRT of 3 days in the MHP tanks with one tank out of service is preferred. The hydrolysis tanks will operate between 165 °F and 175 °F. The tanks will also provide pasteurization of the sludge resulting in Class A biosolids.

After the hydrolysis process is complete, the sludge is pumped to three thermophilic digesters operating in a parallel configuration. Recovery heat is extracted from the sludge prior to sending to the digestion process. A recirculation loop will pump the digested sludge after digestion back to the MHP tanks. This will provide process stability in the MHP tanks as well as reduce more recalcitrant material. A portion of the digested sludge will be pumped to the dewatering equipment and then the biosolids are conveyed to the cake storage bay. Heat recovery will also occur on the digested sludge prior to dewatering. Digester gas produced will be cleaned and stored in the biogas storage. The gas will be burned either in the cogeneration engines or cleaned further to be injected as RNG into the NW Natural pipeline.

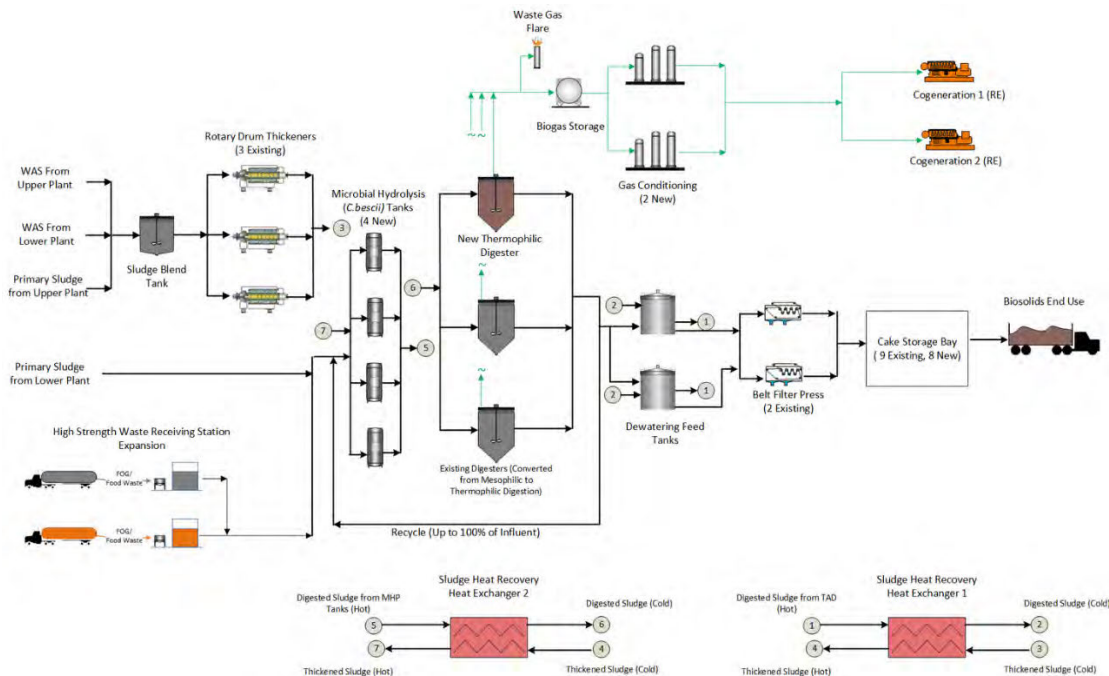


Figure 8: Simplified MHP Process Flow Diagram

Alternatively, MHP system can also be implemented without the construction of the third digester and operating the existing digesters under mesophilic conditions. A simplified process flow diagram is provided in Figure 9. Instead of constructing a third digester to provide additional capacity, an additional

rotary drum thickener will be installed for recuperative thickening. This could be used to delay the construction of a third new digester till 2037.

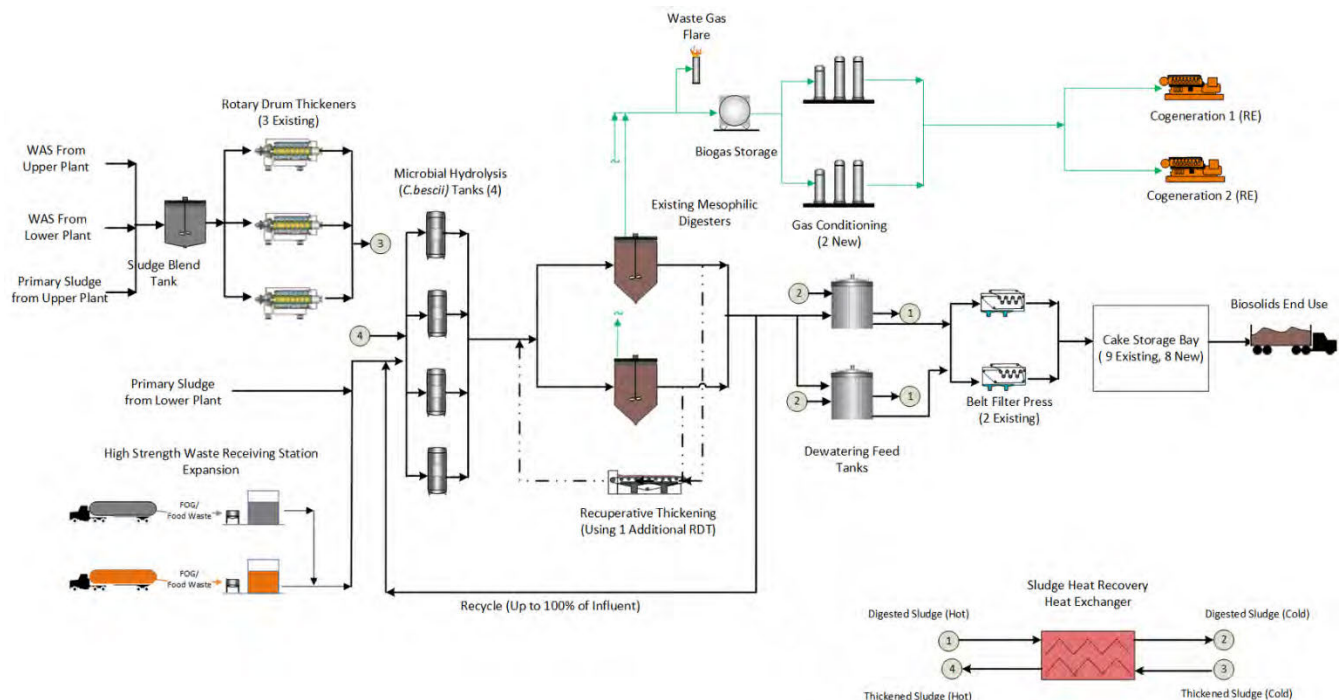


Figure 9: Simplified MHP Process Flow Diagram with recuperative thickening

In order to heat the MHP tanks up to 165-175 °F, a separate high temperature hot water loop system is required to heat the sludge fed to the MHP hydrolysis tanks. Heat recovery from the cogeneration engines is not possible with this loop due to the high temperatures. Therefore, a low temperature hot water loop system will be used to recover heat from cogeneration engines and meet other heating requirements of the digestion system. Separate boilers will be needed for the two different loops.

4.4 Business Case Evaluation

As part of this project, an economic model was developed for the different revenue generating alternates as discussed in Task 2.6 - Power Utility Coordination and Preliminary Economic Model Update. The business case evaluation was updated to include MHP process to determine the breakeven payback period. The following scenarios were considered that included MHP:

- Baseline (no MHP): New mesophilic digester + FOG/gas conditioning rehab
 - Current CIP Project
- Option 1a-i (TAD, no MHP): Renewable Electricity (RE) commodity value + incentives
- Option 1a-ii (w/MHP +TAD): Renewable Electricity (RE) commodity value + incentives
- Option 1a-iii (w/MHP + existing MAD): Renewable Electricity (RE) commodity value + incentives

The capital costs in this BCE included the MHP tanks, heating equipment, mixing pumps and nozzles for the MHP hydrolysis tanks and heat recovery equipment. The remaining inputs to the business case evaluation are described in Task 2.6 - Power Utility coordination and Preliminary Economic Model Update. Table 4 summarizes the capital costs for both the MHP alternates. The capital costs for the baseline

scenario and Option 1a-1 is provided in Task 2.6 - Power Utility coordination and Preliminary Economic Model.

Table 4. Project Cost Summary for Options 1,2, 3

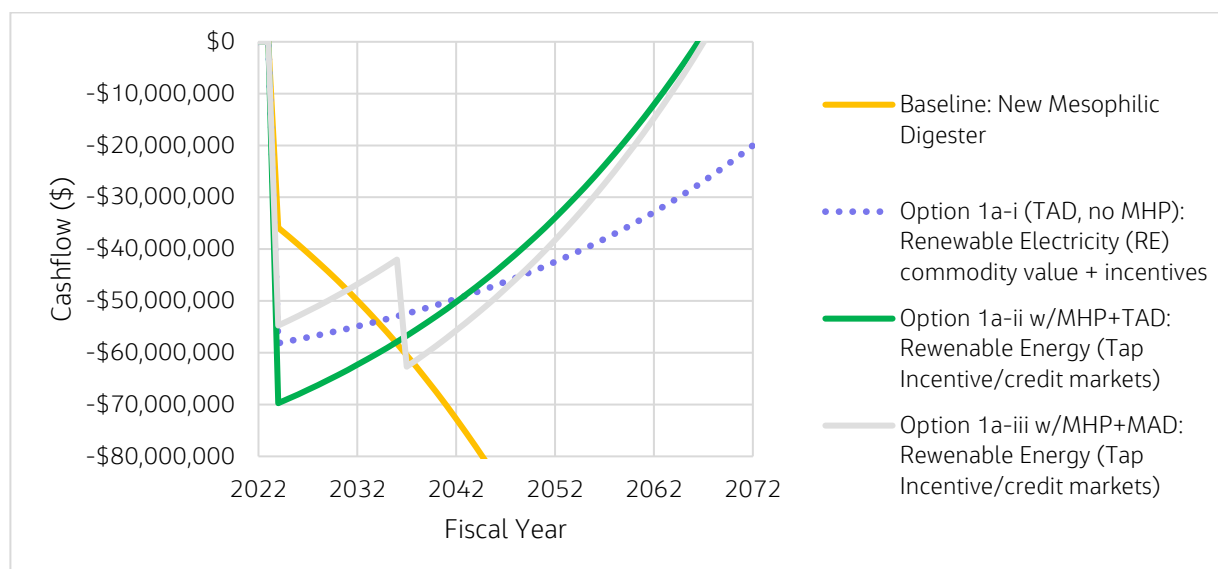
Item	Markup	Option 1a-ii (w/MHP +TAD)	Option 1a-iii (w/MHP + existing MAD)
FOG/FS receiving facility - new and rehab existing	-	\$1,100,000	\$1,100,000
Anaerobic digesters system - convert existing tanks	-	\$4,500,000	\$4,500,000
Anaerobic digester system - new digester and MHP System	-	\$11,100,000	\$11,100,000
Recuperative Thickening – Additional Rotary Drum Thickener	-	\$0	\$500,000
Dewatering, cake conveyance, and cake storage	-	\$600,000	\$600,000
Gas conditioning - new and rehab existing	-	\$8,200,000	\$8,200,000
CHP	-	\$2,500,000	\$2,500,000
Boiler	-	\$800,000	\$800,000
Subtotal		\$28,800,000	\$29,200,000
Contractor Markups			
Mobilization	5%	\$30,100,000	\$30,600,000
General conditions	7%	\$32,200,000	\$32,800,000
Overhead	12%	\$36,100,000	\$36,700,000
Profit	6%	\$38,300,000	\$38,900,000
Insurance & bond	3%	\$39,400,000	\$40,000,000
Contingency			
Design/estimating contingency	30%	\$51,200,000	\$52,100,000
Market adjustment factor	5%	\$53,800,000	\$54,700,000
Project Delivery Costs			
Project and construction management	5%	\$56,500,000	\$57,400,000
Permitting	1%	\$57,000,000	\$57,900,000
Engineering	10%	\$62,400,000	\$63,400,000
Services during construction	5%	\$65,100,000	\$66,100,000
Commissioning	3%	\$66,700,000	\$67,800,000
Gresham administration charge	14%	\$76,000,000	\$77,300,000
Estimated Total Project Capital Cost	-	\$76,000,000	\$77,300,000

Table 4. Project Cost Summary for Options 1,2, 3

Item	Markup	Option 1a-ii (w/MHP +TAD)	Option 1a-iii (w/MHP + existing MAD)
Estimated Total Project Life Cycle Cost	-	\$50,452,000	\$52,235,000

Note: Actual total project cost to fall within -50% and 100% of estimated cost.

For the business case evaluation, the capital costs were compared against the revenue potential in order to establish the possible payback scenarios. The potential revenues include the tipping fees from the FOG and food slurry delivery trucks, and revenues generated from selling renewable electricity (RE). Cashflow projections for each revenue generation option is presented in Figure 10 and Table 5. The cashflow projections include the expected capital costs of the facilities, which depend on the equipment required. In option 1a-iii, the construction of the third digester is deferred till 2037. The cashflow curve sees a drop due to the capital costs associated with constructing the third digester.

**Figure 10 - Renewable Electricity Options**

With & without MHP hydrolysis tanks. Moderate revenue potential with no tax credits/grants

Table 5. Cashflow Breakdown of RE Options with MHP

Scenario	Assumptions	Total Capital Costs (\$M)	Total Credits/Grants (\$M)	Total Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Simple Payback vs Baseline
Baseline (no MHP): New Mesophilic Digester	No add'l FOG/food slurry	(\$32.4)	\$0	(\$1.8)	\$0	\$0.4	--
Option 1a-i (TAD, no MHP): Renewable Electricity	Moderate revenue from incentives; nominal value	(\$55.2)	\$0	(\$2.5)	(\$0.7)	\$2.8	10 years

Scenario	Assumptions	Total Capital Costs (\$M)	Total Credits/Grants (\$M)	Total Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Simple Payback vs Baseline
Commodity Value + Incentives	for OR CFP credits and eRINs						
Option 1a-ii w/MHP+TAD: Renewable Energy (Tap Incentive/credit markets)		(\$66.5)	\$0	(\$2.2)	(\$0.4)	\$2.9	9 years
Option 1a-iii w/MHP+MAD: Renewable Energy (Tap Incentive/credit markets)		(\$52.4)	\$0	(\$2.1)	(\$0.3)	\$2.9	13 years

\$M = million dollars.

4.5 Impacts to Biosolids

The digested sludge generated from the lab scale testing of *C. bescii* on the WWTP sludge was tested for its dewaterability. The sludge was collected and shipped to Bucknell University in Lewisburg, Pennsylvania for bench scale dewatering. The dewaterability test demonstrated that the MHP process resulted in an increase in cake solids of 22 percent, whereas the control sludge was only 14 percent., although in the laboratory setting the polymer demand did increase. Additional testing would be required to better assess the polymer demand impacts. Additional details of the dewatering test can be found in *Caldicellulosiruptor Bescii* Impacts on Dewatering – Laboratory Dewatering Test Results (Jacobs, 2021). The results from the dewaterability test have been used to determine the biosolids production for the different options.

Figure 11 shows the quantities of biosolids produced for the Year 2037 annual average conditions for the different options. The baseline scenario with three mesophilic digesters produces the most amount of biosolids. In this scenario, the WWTP continues to use existing dewatering equipment which can only produce 12-14 percent cake. With thermophilic digestion, it is anticipated the dewatering should improve to around 16 percent cake with new dewatering equipment and therefore the quantity of biosolids produced is lower than the baseline option. However, in both these options only Class B biosolids will be produced. MHP processes generate the least amount of biosolids due to increased dewaterability of the digested sludge as observed from prior testing. The cake solids of 22 percent were assumed. This reduces the volume of sludge that the WWTP needs to haul resulting in significant cost savings. The MHP process also generates a Class A biosolids product, which can be used at any application site without any pathogen-related restrictions.

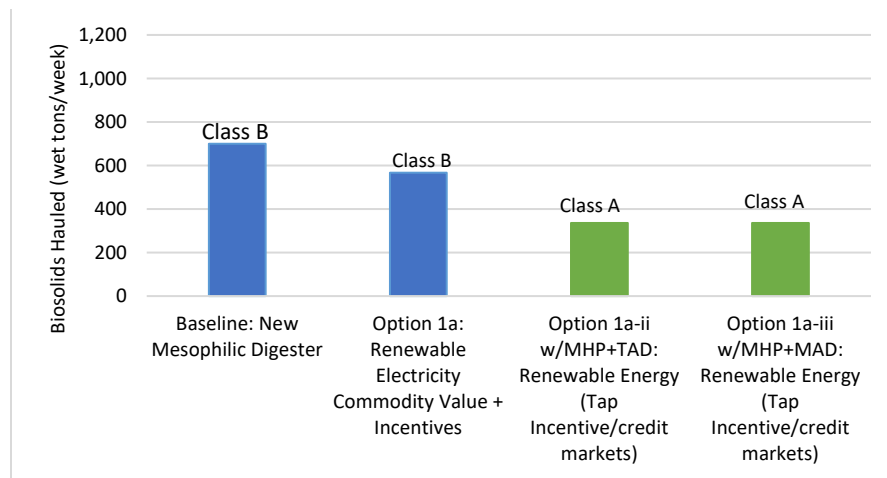


Figure 11: 2037 Annual Average Biosolids Production Rate for the different Options

5. Micro-Aeration Evaluation

Micro-aeration involves the dosing of a small amount of air during the digestion process. It is a process-integrated biochemical method of lowering hydrogen sulfide (H_2S) in the biogas prior to downstream gas treatment. The process takes place inside the digester and the bacteria responsible for the sulfide oxidation are already present in the feed sludge. Micro-aeration in anaerobic digesters can be defined as the dosing of a small amount of ambient air (or oxygen) into a digester system such that there is zero residual concentration of oxygen present in the sludge and limited (trace) consumption of oxygen.

Creating microaerobic conditions during anaerobic digestion has proven to be an effective method for removing H_2S from biogas (Krayzelova et al., 2014; Jenicek et al., 2008; Jenicek et al., 2017; Khanal and Huang, 2003; Díaz et al., 2010; Ramos and Polanco, 2013; Díaz et al., 2011). Micro-aeration has been researched and used with agricultural biogas plants and tested at municipal wastewater treatment plants. Micro-aeration has been shown to achieve near-complete oxidation of H_2S , and because the process occurs biologically rather than via reaction with iron oxide media, it can be significantly less expensive. Ideally, sulfide in the digester gas and digested sludge is completely converted to elemental sulfur and mainly discharged with the digested sludge. Micro-aeration has been tested at full-scale municipal wastewater treatment facilities in Europe where several facilities have been in operation for at least 10 years. All facilities achieve at least 74 percent H_2S removal efficiency, but most facilities achieve 94 percent removal efficiency or greater (Jenicek et al., 2017). More recently in 2019 a full-scale pilot was conducted at LOTT's Budd Inlet wastewater facility in Olympia, WA. Based on those successful results of approximately 85 percent H_2S reduction, a full-scale permanent system was designed and installed at Budd Inlet, which is currently being commissioned. The intent is to not operate this new system until the digester mixing is change from gas mixing to linear motion mixing, the covers are converted from floating covers to fixed covers, and the single emergency pressure relief valves (PRVs) are changed out to dual manifolded PRVs so that the flame arrestors can be cleaned without taking the digester off-line (a project is currently under design to implement these improvements). The current gas mixing at Budd Inlet tends to draw the injected air up to the head space too rapidly resulting in sulfur deposition on the underside of the digester floating covers including the flame arrestors that are part of the single PRVs.

In addition to near-complete H_2S removal, there is evidence that micro-aeration can enhance the digestion process by increasing volatile solids removal, improving the digester's ability to respond to shock-loading, and possibly reducing foaming. There is also evidence that micro-aeration can increase digested solids dewatered cake solids content and reduce the chemical oxygen demand and dissolved sulfide concentration in the digested sludge filtrate (Jenicek et al., 2008).

It should be noted that there are potential limitations and disadvantages to micro-aeration, including partial oxidation of organic matter, potential scaling of digester walls and pipes with elemental sulfur (which have been observed in full-scale pilot tests (discussed above), and process control challenges associated with air injection dose rates.

The WWTP currently uses iron sponges for H₂S removal in the biogas. This system requires media regeneration and eventually replacement which is expensive. As part of the project, Jacobs conducted a desktop evaluation of implementing micro-aeration technology at the WWTP digesters for reduction of H₂S in the biogas prior to the biogas treatment systems. A business case evaluation was completed to provide the breakeven payback period. The business case included:

- Capital Costs - \$934,000
 - Advancement of Cost Engineering International (ACE) Class 5 Estimate
 - This includes design fee, project delivery costs and a Gresham administration fee.
- Operations and maintenance (O&M) costs
 - Current annual O&M cost of the iron sponge - \$124,000
 - Annual O&M cost with micro-aeration - \$49,600

Table 6 includes the major assumptions included in the economic analysis.

Table 6. Economic Model Assumptions

Parameter	Value / Unit
Bond rate	4.5 percent
Inflation rate	3.0 percent
Real discount rate	1.5 percent
Capital period	20 years

A simple payback calculation was developed to estimate the payback period for the micro-aeration system compared to the current operations which is the baseline conditions. The payback period is determined by the intersection of the cumulative cost curve for micro-aeration against the baseline curve. It is also dependent on the percentage removal of H₂S as shown in Table 7. With increase percentage removal for H₂S, the payback period is reduced. However, for this analysis a conservative value of 50 percent removal is assumed, and the payback period is 15 years.

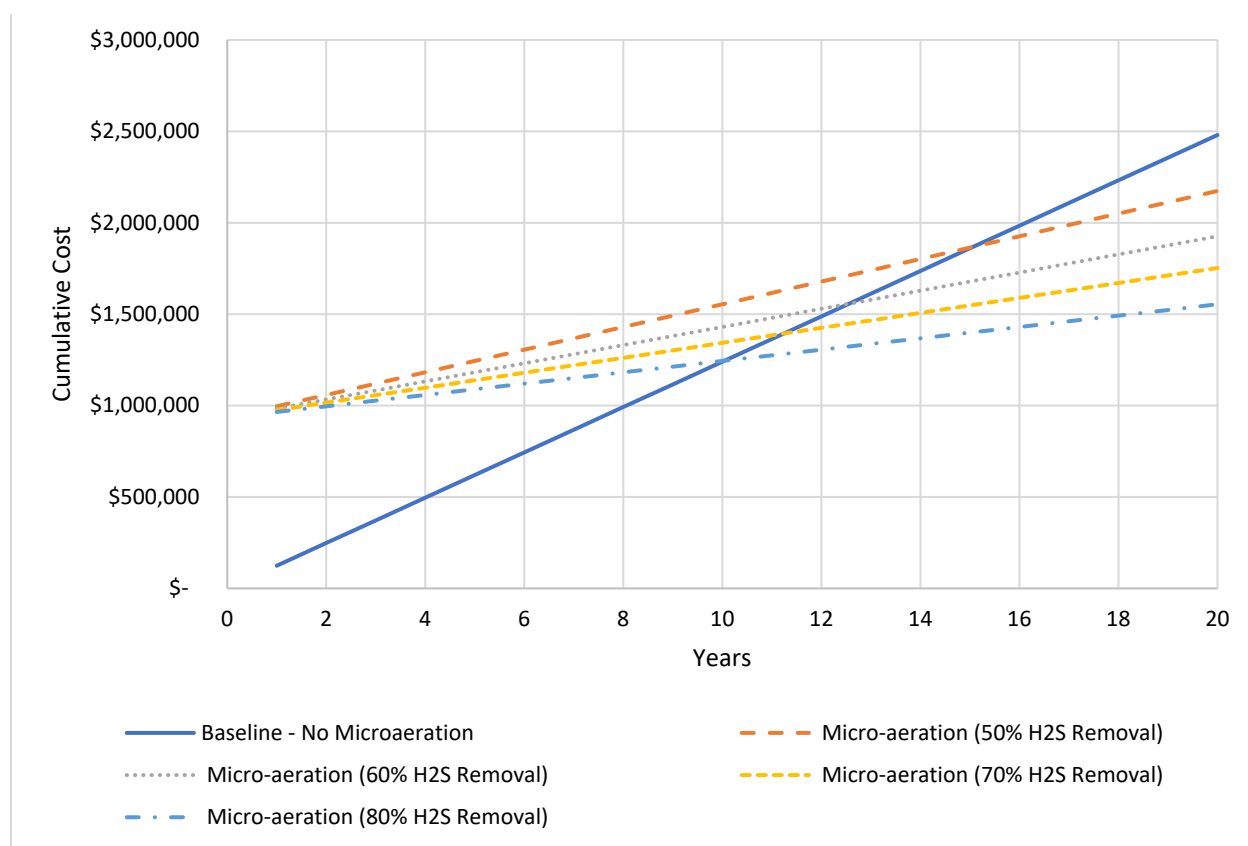


Figure 12: Simple Payback Period Calculation for Micro-Aeration System

Table 7: Payback period for micro-aeration system at Gresham based on hydrogen sulfide removal efficiency

Assumed H2S Removal Efficiency	Estimated Payback	Comments
50%	15	Most conservative in terms of micro-aeration performance at Gresham
60%	13	
70%	11	
80%	10	Most optimistic

Note: Data from LOTT's Budd Inlet pilot indicated 80 to 85% removal of H₂S in the biogas using micro-aeration.

This evaluation was completed based on information obtained from other facilities that have micro-aeration or carried out full scale pilot testing. Although this project will not involve conducting a site-specific pilot of micro-aeration, a potential recommendation of this evaluation is to conduct a pilot at the

WWTP which could entail a lab scale testing utilizing the digestion pilot system or a full-scale pilot as part of the next phase of this project.

6. Summary and Conclusions

The conclusions are summarized as follows:

- Third Digestion Geometry: Silo digester is the first preference. Hybrid (approaching silo shape) will be selected if there is a need to accommodate site constraints while provide enhance performance, operability and maintainability relative to a pancake
- Operating configuration: Thermophilic digestion with ability to operate in parallel as preferred configuration. Series operation is also possible but is only recommended for short durations.
- Phasing:
 - Phase 1: Construction of a third digester
 - Phase 2: Conversion of the existing two digesters to thermophilic
- MHP has not been included in the predesign documents at this time. Space on the site has been reserved such that if the City later reviews operating data from other facilities (which are currently in design) and finds MHP more beneficial than previously assumed, then MHP can be integrated into the project at that time.
- Micro-aeration has not been included in the predesign documents at this time. The City may opt to conduct a full-scale pilot to better quantify the site specific air feed rates and hydrogen sulfide removal performance. These data could then be utilized to update and refine the previously conducted payback analysis and then the City could determine if the micro-aeration should be added into this project.

7. Attachments

- Attachment 1: Powerpoint slides from workshops
- Attachment 2: Ovivo proposals on linear motion mixer upgrades

Subject	Business Case Evaluation Workshop – Meeting Notes
Project Name	WWTP Anaerobic Digestion and Cogeneration Expansion Project
Project Number	311263 // D3621900
Prepared by	Kristen Jackson
Location	In person / MS Teams
Date/Time	October 18, 2022 / 11:00 am – 1:00 pm
Participants	Gresham: Rob Chapler, Alan Johnston, Jacob Corum Jacobs: Matt Noesen, Corey Klibert, Kristen Jackson, Yash Chaudhary*, Ben Herman* *attendees on phone

Action Items (compiled from below)	Responsible Lead
Update BCE with input from City (existing digester covers to baseline, check current maintenance costs, add “hybrid” option to the non-monetary section)	Jacobs
Jacobs will update the funding memo to include IRA options	Jacobs
Decisions (compiled from below – and added to decision log)	Responsible Lead
Preferred option for revenue was the hybrid approach (greater flexibility to optimize revenue generation).	City
Payback analysis of Hybrid Option based on continuing to run two existing 400 kW engines, City suggests looking at <u>two new 600 kW engines</u>.	City

Notes:

Item	Lead
1 Introduction	
Digestion (45 mins) <ul style="list-style-type: none"> Thermophilic Conversion <ul style="list-style-type: none"> Are there more odors with thermophilic digestion? Dewatering can be more successful with sludge that is a cooler temperature. Increased odors from thermophilic sludge dissipate as temperature returns to ambient temperature. 	
2 <ul style="list-style-type: none"> MHP – to be covered separately. Microaeration – payback analysis based on conservative assumption for H₂S reduction (50%). Other facilities are observing up to 80% reduction. Net Zero – discuss importance in weighing alternatives <ul style="list-style-type: none"> City would like to still maintain a net zero approach irrespective of alternatives. 	

Item	Lead
<p>RE vs. RNG vs. Hybrid</p> <ul style="list-style-type: none"> • Project capital costs are high. May want to look at phasing. Hopefully some of the material costs are coming down and that should help lower the upfront capital costs. Some value engineering/phasing will be needed in the future. <ul style="list-style-type: none"> ○ Finding available grant funding will be important for this project • Why have RE/RNG/Hybrid options increased in cost more than Baseline Option since 2020? <ul style="list-style-type: none"> ○ RE/RNG/Hybrid options carry costs for replacement covers for the existing digesters, those costs will be added to Baseline option for better cost comparison. • Preferred option for revenue was the hybrid approach (greater flexibility to optimize revenue generation). • Payback analysis of Hybrid Option based on continuing to run two existing 400 kW engines, City suggests looking at two new 600 kW option. • City suggested checking current cogen maintenance costs with Ops. 	
<p>Other Topics</p> <ul style="list-style-type: none"> • CEPT – to be covered separately. • Dewatering coordination – to be covered separately. • Funding (IRA) <ul style="list-style-type: none"> ○ ODOE could also provide opportunities to mitigate cost ○ Jacobs will update the funding memo to include IRA options 	
<p>Schedule & Next Steps</p> <ul style="list-style-type: none"> • Update BCE payback analysis with input from meeting and up-to-date operational costs for cogen maintenance, RNG system maintenance, labor, etc. 	

Bold/Red = meetings notes

Business Case Evaluation Workshop

Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project
October 18th, 2022 (slides updated 12/6/2022)

Culture of Caring – Daylight Savings...

<https://www.sleepfoundation.org/circadian-rhythm/how-to-prepare-for-daylight-saving-time>

How to Prepare

- Maintaining a fixed sleep schedule on both weekdays and weekends
- Keeping a stable routine to get ready for bed each night
- Limiting or avoiding caffeine and alcohol, especially in the afternoon and evening
- Going “device free” for at least 30 minutes before bed
- Blocking out unwanted noise and light from your bedroom and/or using accessories like a sleep mask and ear plugs



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How to Prepare for the Start and End of Daylight Saving Time

Updated June 10, 2022



Written by
[Eric Suni, Staff Writer](#)



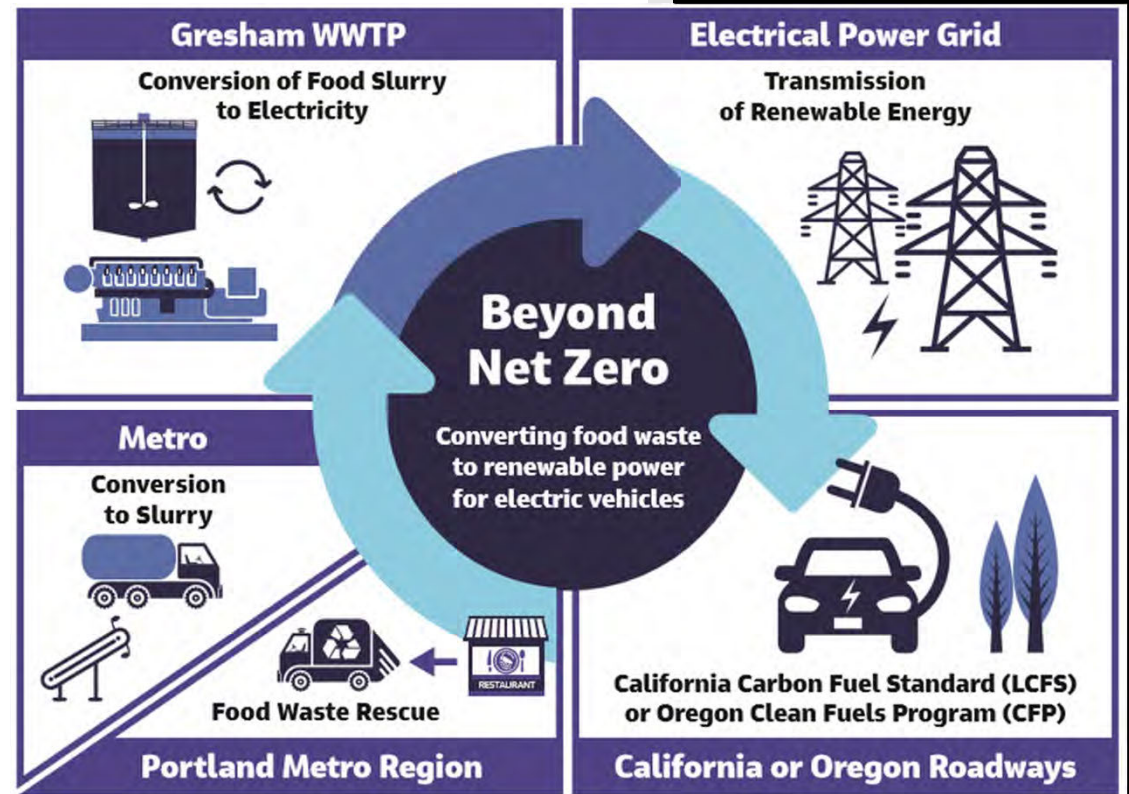
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Our team of writers, editors, and medical experts rigorously evaluates each article to ensure the information is accurate and exclusively cites reputable sources. [Learn More](#)

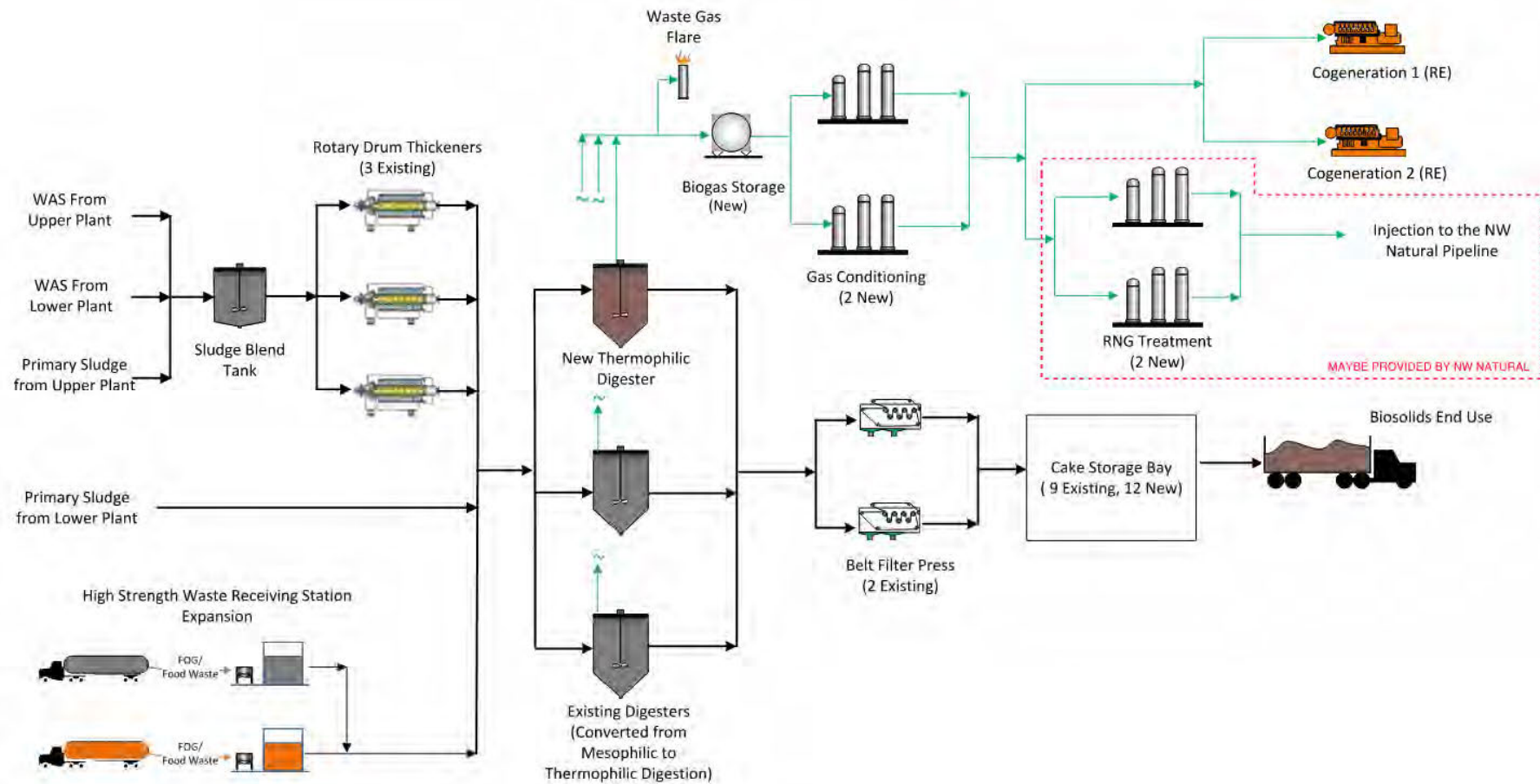
Agenda

Overview

- Introduction – Scope Overview
- Digestion (~45 mins)
 - Thermophilic conversion
 - MHP (C. Bescii)
 - Microaeration
- RE vs. RNG vs. Hybrid (~1 hour)
- Other topics (~15 minutes)
 - CEPT
 - Dewatering coordination
 - Funding (IRA)
- Schedule & Next Steps



Overview of Project Components



Overview of Options

- Baseline: New mesophilic digester + FOG/gas conditioning rehab
- Option 1: Renewable Electricity (RE)
- Option 2: Renewable Natural Gas (RNG)
- Option 3: Hybrid (Baseload cogen + sell excess RNG)

Project Components and Cost Summary Breakdown

Facility	Markup	Baseline	RE	RNG	Hybrid
FOG/FW Receiving Facility - New and Rehab Existing		\$700,000	\$1,100,000	\$1,100,000	\$1,100,000
Anaerobic Digester System - Convert Existing Tanks		\$5,000,000	\$5,500,000	\$5,500,000	\$5,500,000
Anaerobic Digester System - New Tank	Updated to include the cost of cover replacement	\$6,500,000	\$6,500,000	\$6,500,000	\$6,500,000
Dewatering, Cake Conveyance, and Cake Storage		\$0	\$700,000	\$700,000	\$700,000
Gas Conditioning - New and Rehab Existing		\$1,000,000	\$2,100,000	\$8,200,000	\$8,200,000
CHP		\$0	\$5,100,000	\$0	\$2,500,000
Boilers		\$0	\$800,000	\$1,300,000	\$800,000
Subtotal		\$13,200,000	\$21,800,000	\$23,300,000	\$25,300,000
Contractor Markups					
Mobilization	5%	\$13,900,000	\$22,900,000	\$24,500,000	\$26,500,000
General Conditions	7%	\$14,900,000	\$24,500,000	\$26,200,000	\$28,400,000
Overhead	12%	\$16,600,000	\$27,500,000	\$29,400,000	\$31,800,000
Profit	6%	\$17,600,000	\$29,100,000	\$31,100,000	\$33,700,000
Insurance & Bond	3%	\$18,200,000	\$30,000,000	\$32,000,000	\$34,700,000
Contingency					
Design/Estimating Contingency	30%	\$23,600,000	\$39,000,000	\$41,700,000	\$45,100,000
Market Adjustment Factor	5%	\$24,800,000	\$40,900,000	\$43,700,000	\$47,400,000
Project Delivery Costs					
Project and Construction Management	5%	\$26,100,000	\$43,000,000	\$45,900,000	\$49,700,000
Permitting	1%	\$26,300,000	\$43,400,000	\$46,400,000	\$50,200,000
Engineering	10%	\$28,800,000	\$47,500,000	\$50,700,000	\$55,000,000
Services During Construction	5%	\$30,000,000	\$49,500,000	\$52,900,000	\$57,300,000
Commissioning	3%	\$30,800,000	\$50,700,000	\$54,200,000	\$58,700,000
Gresham Administration Charge	14%	\$35,100,000	\$57,800,000	\$61,800,000	\$67,000,000
Estimated Total Project Cost		\$35,100,000	\$57,800,000	\$61,800,000	\$67,000,000

1x new 600 kWe cogen at initial construction w/additional engine phased later

Actual total project cost to fall within -50% and 100% of estimated cost; see slide notes for additional discussion

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Opportunities to mitigate capital cost

- Grants/tax credits
 - Inflation Reduction Act of 2022, Energy Trust of Oregon, SRF
- P3 Partnership
 - 3rd party invest, operate, recoup revenue
- NWN
 - Potential for NWN to finance and operate the RNG system and interconnection fee.
 - Lower revenue generated from selling the RNG.

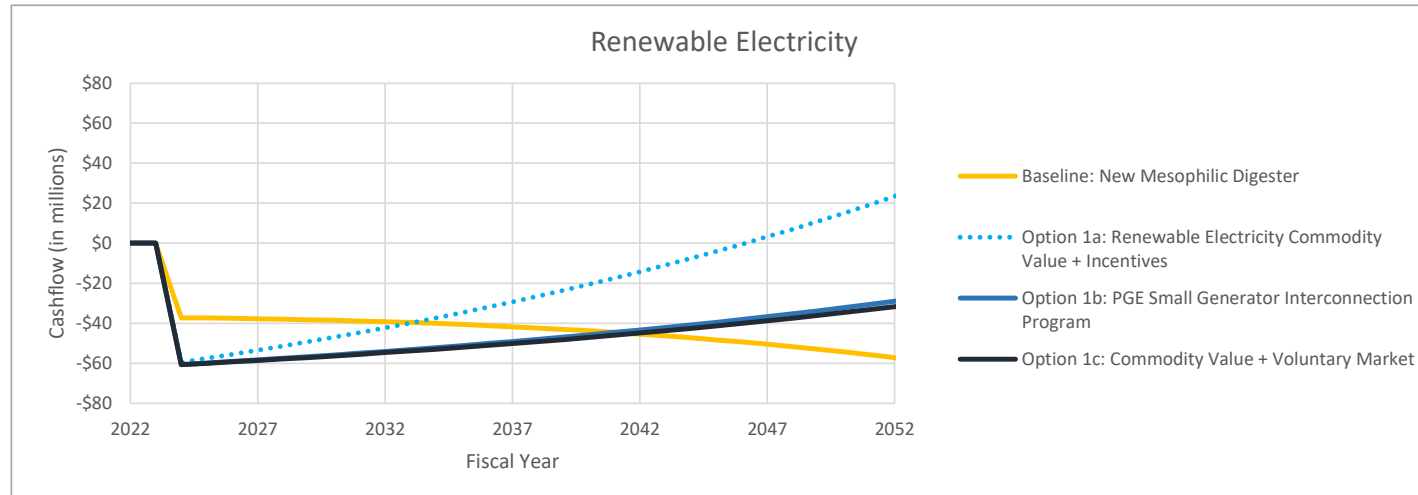
Revenue potential of available options for renewable energy

Technology	Scenario	Description	Estimated Range of Revenue			Comments
			Tipping Fees	Min from Renewables	Max from Renewables	
Renewable Electricity	Option 1A	Commodity Value of Elec + Incentives	\$1,200,000	\$1,000,000	\$2,800,000	Minimum: Sale of commodity plus current market value of LCFS credits Maximum: Value of commodity plus nominal value of OCFP credits and eRINs
	Option 1B	PGE – Small Generator Program	\$1,200,000	\$380,000	\$570,000	Range of \$0.04 - \$0.06/kWh (no wheeling charge)
	Option 1C	Commodity Value + Voluntary Market	\$1,200,000	\$380,000	\$530,000	Range of \$0.05 - \$0.07/kWh unit cost minus 20% transmission wheeling charge from PGE
Renewable Natural Gas	Option 2A	Commodity Value of RNG + Incentives	\$1,200,000	\$2,600,000	\$4,700,000	Minimum: Sale of commodity plus current market value of LCFS credits and RINs Maximum: Value of commodity plus nominal value of OCFP credits and RINs *Assumes all biogas produced is injected to the RNG pipeline, WWTP purchases power and natural gas at retail rate.
	Option 2B	Sell RNG to NWN	\$1,200,000	\$730,000	\$1,900,000	Minimum: NWN provides gas treatment and NG pipeline interconnection Maximum: Owner provides all infrastructure *Assumes all biogas produced is injected to the RNG pipeline, WWTP purchases power and natural gas at retail rate.
Hybrid (RE/RNG)	Option 3A	Baseload Cogen + Commodity Value of RNG + Incentives	\$1,200,000	\$1,500,000	\$2,600,000	<i>Baseload cogen to provide plant power under current NMA</i> Minimum: NWN provides gas treatment and NG pipeline interconnection Maximum: Owner provides all infrastructure
	Option 3B	Baseload Cogen + Sell Excess RNG to NWN (fixed-price contract)	\$1,200,000	\$380,000	\$1,000,000	<i>Baseload cogen to provide plant power under current NMA</i> Minimum: NWN provides gas treatment and NG pipeline interconnection Maximum: Owner provides all infrastructure

Key Assumptions for Payback Analysis

- To account for costs that would otherwise be required according to the current capital improvements plan, the annual operating costs of each option were compared to those of the Baseline Option.
 - This allows the payback of each option to be separated from the investment that would otherwise be required for routine upgrades and expansions at the facility.
 - The differences in annual operating costs break down as follows:
 - Labor: additional FTE's related to add'l FOG/FW
 - Electricity/NG: additional energy costs (if any) incurred by liquid organic waste processing
 - Chemicals: additional polymer cost due to increase in sludge volume to dewater from FOG/FW digestion
 - Biosolids Hauling/Disposal: difference between cost of hauling mesophilically digested municipal sludge and thermophilically digested muni sludge + add'l FOG/FW

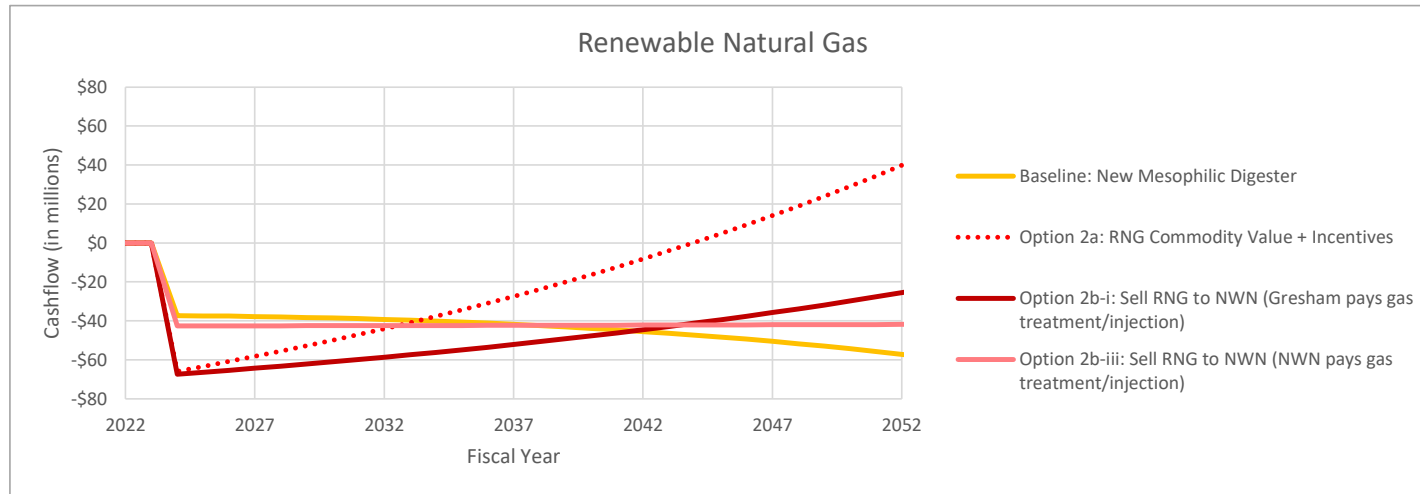
Comparison of Renewable Electricity options



Scenario	Assumptions	Total Capital Costs	Total Credits/Grants	Total Annual Operating Costs	Annual Operating Costs vs Baseline	Annual Revenue	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food waste	(\$35,100,000)	\$0	(\$1,800,000)	\$0	\$400,000	--
Option 1a: Renewable Electricity Commodity Value + Incentives	Moderate revenue from incentives; nominal value for OCFP credits and eRINs	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$2,800,000	10 years
Option 1b: PGE Small Generator Interconnection Program	Estimated revenue from \$0.05/kWh rate	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$1,700,000	18 years
Option 1c: Commodity Value + Voluntary Market	Estimated revenue from \$0.055/kWh rate	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$1,600,000	18 years

Actual total project cost to fall within -50% and 100% of estimated cost

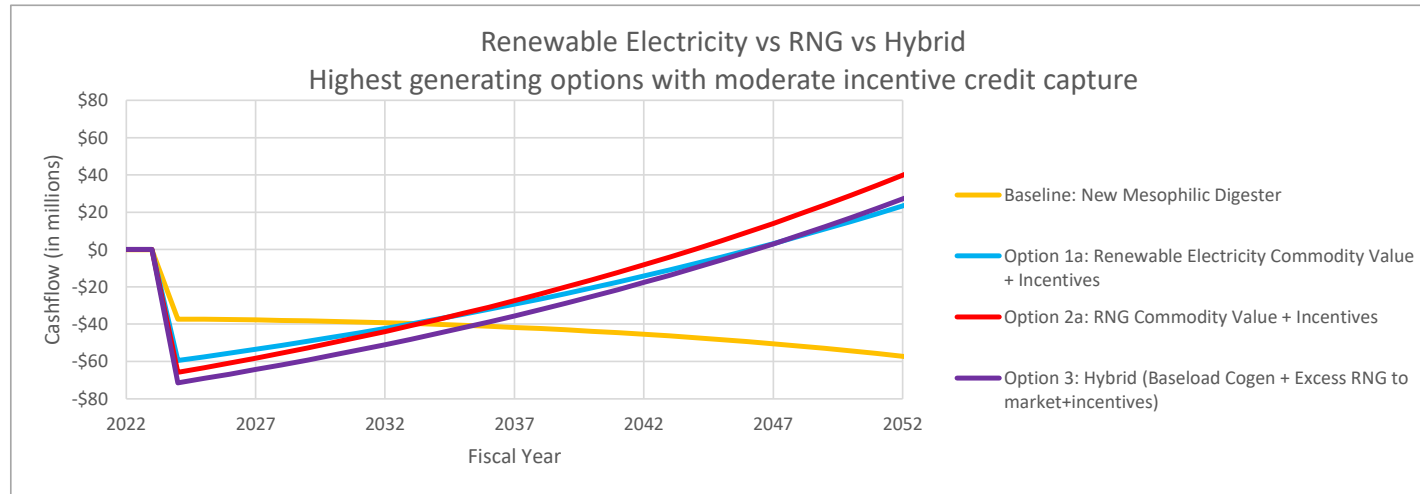
Comparison of Renewable Natural Gas options



Scenario	Assumptions	Total Capital Costs	Total Credits/Grants	Total Annual Operating Costs	Annual Operating Costs vs Baseline	Annual Revenue	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food waste	(\$35,100,000)	\$0	(\$1,800,000)	\$0	\$400,000	--
Option 2a: RNG Commodity Value + Incentives	Moderate revenue from incentives	(\$64,300,000)	\$0	(\$3,700,000)	(\$1,900,000)	\$4,500,000	10 years
Option 2b-i: Sell RNG to NWN (Gresham pays gas treatment/injection)	\$13/mmBTU	(\$64,300,000)	\$0	(\$3,700,000)	(\$1,900,000)	\$3,100,000	18 years
Option 2b-ii: Sell RNG to NWN (NWN pays gas treatment/injection)	\$5/mmBTU	(\$40,200,000)	\$0	(\$3,400,000)	(\$1,600,000)	\$2,000,000	14 years

Actual total project cost to fall within -50% and 100% of estimated cost

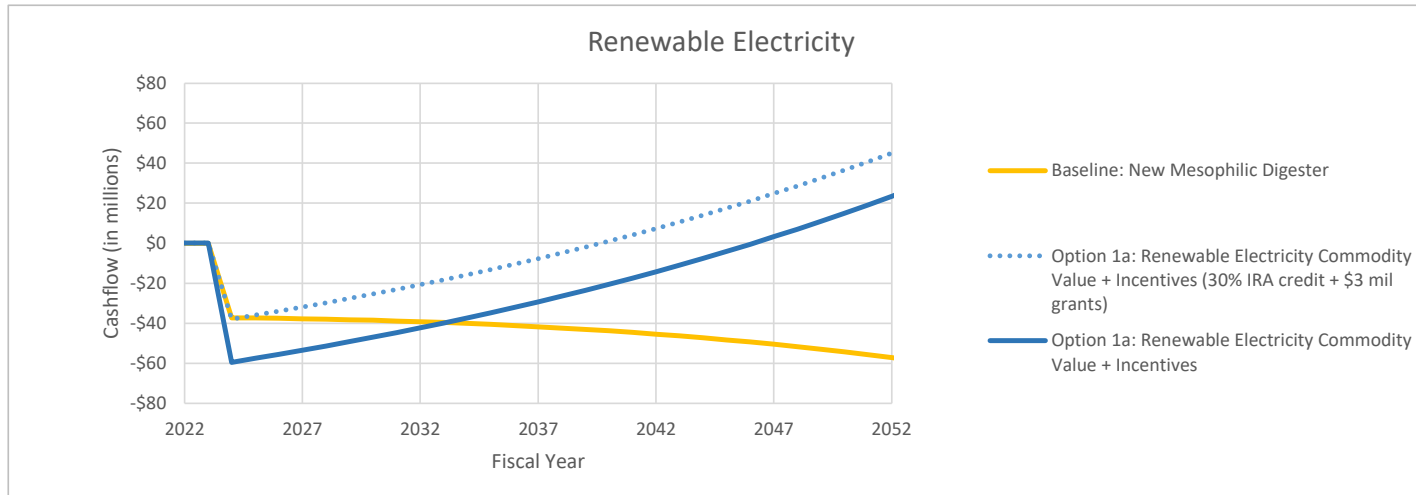
Comparison of RE, RNG, and Hybrid options



Scenario	Assumptions	Total Capital Costs	Total Credits/Grants	Total Annual Operating Costs	Annual Operating Costs vs Baseline	Annual Revenue	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food waste	(\$35,100,000)	\$0	(\$1,800,000)	\$0	\$400,000	--
Option 1a: Renewable Electricity Commodity Value + Incentives	Moderate revenue from incentives; nominal value OCFP credits & eRINs	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$2,800,000	10 years
Option 2a: RNG Commodity Value + Incentives	Moderate revenue from incentives	(\$64,300,000)	\$0	(\$3,700,000)	(\$1,900,000)	\$4,500,000	10 years
Option 3: Hybrid (Baseload Cogen + Excess RNG to market+incentives)	Moderate revenue from incentives	(\$69,500,000)	\$0	(\$2,400,000)	(\$600,000)	\$3,100,000	12 years

Actual total project cost to fall within -50% and 100% of estimated cost

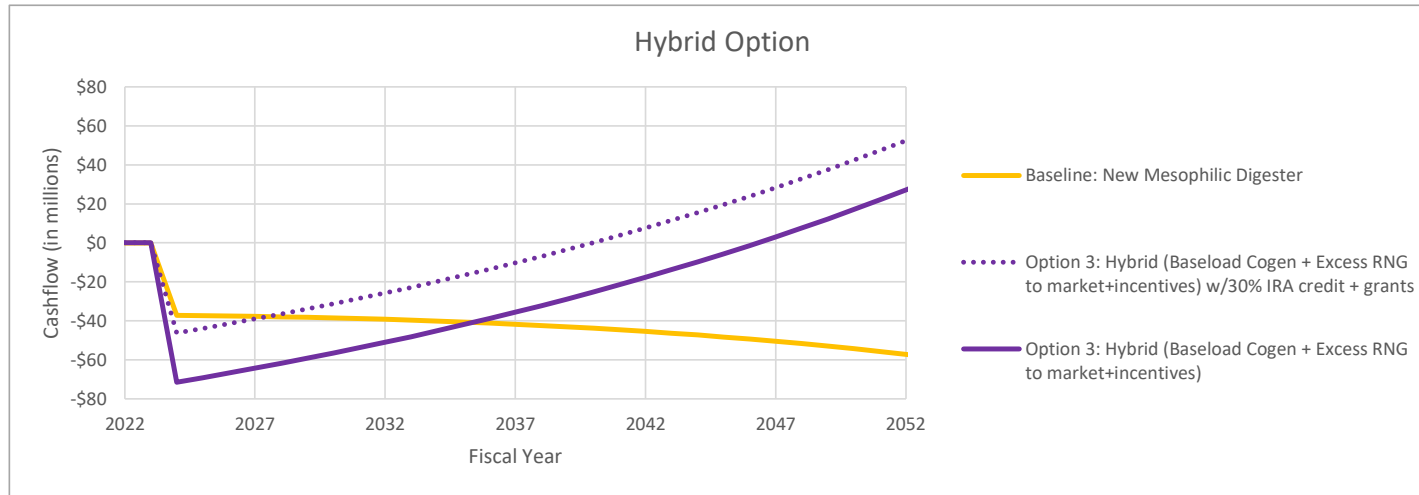
Effect of IRA tax credit + grants on payback



Scenario	Assumptions	Total Capital Costs	Total Credits/Grants	Total Annual Operating Costs	Annual Operating Costs vs Baseline	Annual Revenue	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food waste	(\$35,100,000)	\$0	(\$1,800,000)	\$0	\$400,000	--
Option 1a: Renewable Electricity Commodity Value + Incentives	Moderate revenue from incentives; nominal value OCFP credits & eRINs	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$2,800,000	10 years
Option 1a: Renewable Electricity Commodity Value + Incentives (30% IRA credit + \$3 mil grants)	Moderate revenue from incentives; nominal value OCFP credits & eRINs	(\$37,500,000)	\$20,300,000	(\$2,500,000)	(\$600,000)	\$2,800,000	1 year

Actual total project cost to fall within -50% and 100% of estimated cost

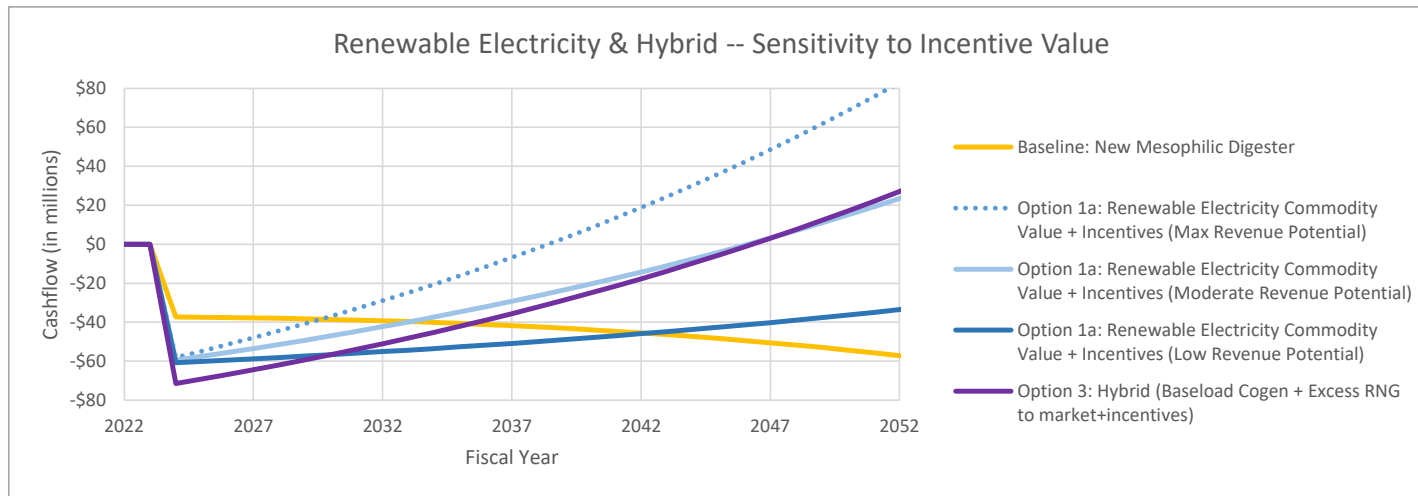
Effect of IRA tax credit + grants on payback



Scenario	Assumptions	Total Capital Costs	Total Credits/Grants	Total Annual Operating Costs	Annual Operating Costs vs Baseline	Annual Revenue	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food waste	(\$35,100,000)	\$0	(\$1,800,000)	\$0	\$400,000	--
Option 3: Hybrid (Baseload Cogen + Excess RNG to market+incentives)	Moderate revenue from incentives	(\$69,500,000)	\$0	(\$2,400,000)	(\$600,000)	\$3,100,000	12 years
Option 3: Hybrid (Baseload Cogen + Excess RNG to market+incentives) w/30% IRA credit + grants	Moderate revenue from incentives	(\$45,600,000)	\$23,900,000	(\$2,400,000)	(\$600,000)	\$3,100,000	4 years

Actual total project cost to fall within -50% and 100% of estimated cost

Sensitivity of Renewable Electricity to Incentive Value

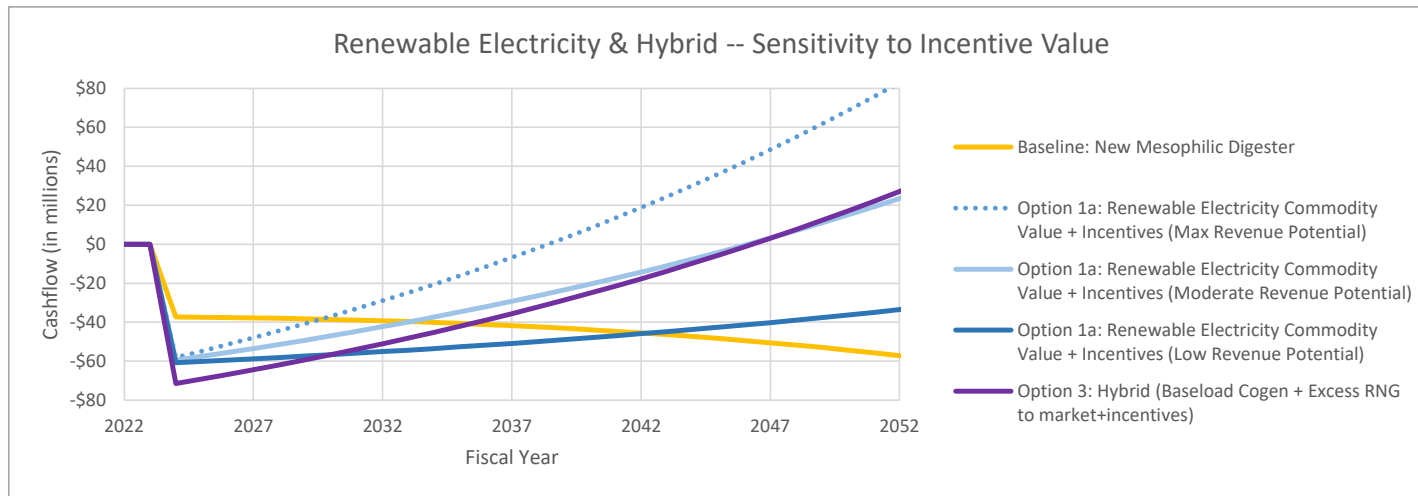


Scenario	Assumptions	Total Capital Costs	Total Credits/Grants	Total Annual Operating Costs	Annual Operating Costs vs Baseline	Annual Revenue	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food waste	(\$35,100,000)	\$0	(\$1,800,000)	\$0	\$400,000	--
Option 1a: Renewable Electricity Commodity Value + Incentives (Max Revenue Potential)	Highest revenue from incentives; nominal value OCFP credits & eRINs under most favorable off-take scenarios	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$4,000,000	6 years
Option 1a: Renewable Electricity Commodity Value + Incentives (Moderate Revenue Potential)	Moderate revenue from incentives; nominal value OCFP credits & eRINs	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$2,800,000	10 years
Option 1a: Renewable Electricity Commodity Value + Incentives (Low Revenue Potential)	Low revenue from incentives; current value of LCFS credits without eRINs	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$1,600,000	19 years
Option 3: Hybrid (Baseload Cogen + Excess RNG to market+incentives)	Moderate revenue from incentives	(\$69,500,000)	\$0	(\$2,400,000)	(\$600,000)	\$3,100,000	12 years

15 Actual total project cost to fall within -50% and 100% of estimated cost

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Sensitivity of Renewable Electricity to Incentive Value



Scenario	Assumptions	Total Capital Costs	Total Credits/Grants	Total Annual Operating Costs	Annual Operating Costs vs Baseline	Annual Revenue	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food waste	(\$35,100,000)	\$0	(\$1,800,000)	\$0	\$400,000	--
Option 1a: Renewable Electricity Commodity Value + Incentives (Max Revenue Potential)	Highest revenue from incentives; nominal value OCFP credits & eRINs under most favorable off-take scenarios	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$4,000,000	6 years
Option 1a: Renewable Electricity Commodity Value + Incentives (Moderate Revenue Potential)	Moderate revenue from incentives; nominal value OCFP credits & eRINs	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$2,800,000	10 years
Option 1a: Renewable Electricity Commodity Value + Incentives (Low Revenue Potential)	Low revenue from incentives; current value of LCFS credits without eRINs	(\$57,800,000)	\$0	(\$2,500,000)	(\$600,000)	\$1,600,000	19 years
Option 3: Hybrid (Baseload Cogen + Excess RNG to market+incentives)	Moderate revenue from incentives	(\$69,500,000)	\$0	(\$2,400,000)	(\$600,000)	\$3,100,000	12 years

16 Actual total project cost to fall within -50% and 100% of estimated cost

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Microaeration

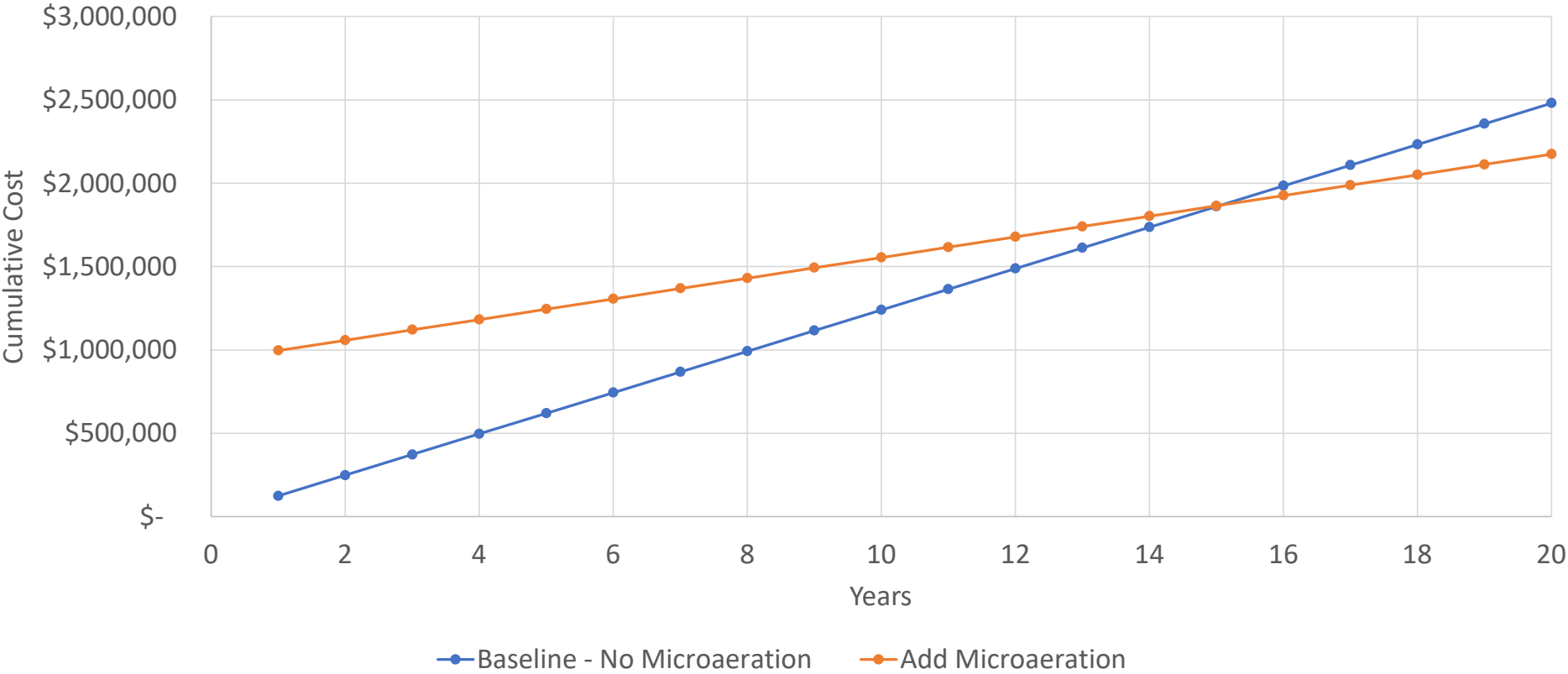
What is Microaeration?

- Dosing small amount of air during the digestion process
- Process-integrated biochemical method of removing H_2S in digesters
- Bacteria responsible for the sulfide oxidation present in feed sludge
- Oxygen consumed in the reaction
- Requires monitoring of air injected and oxygen in digester gas
- May result in partial oxidation of organic matter
- Potential elemental sulfur scaling

Microaeration for H₂S Mitigation BCE

- Historically the raw digester has an average of 650 ppm H₂S (max 1200 ppm)
- Results from LOTT Budd Inlet Facility Pilot operation indicated up to 80% reduction of H₂S produced in the digesters
 - For Gresham, assume 50% reduction in H₂S
- Total Capital Cost \$934,000 (estimated based on LOTT Budd Inlet Facility Project)
- Current Annual Iron Sponge Operational Cost \$124,000
- Annual Iron Sponge Operational Cost with Microaeration: \$62,000

Microaeration for H₂S Mitigation BCE



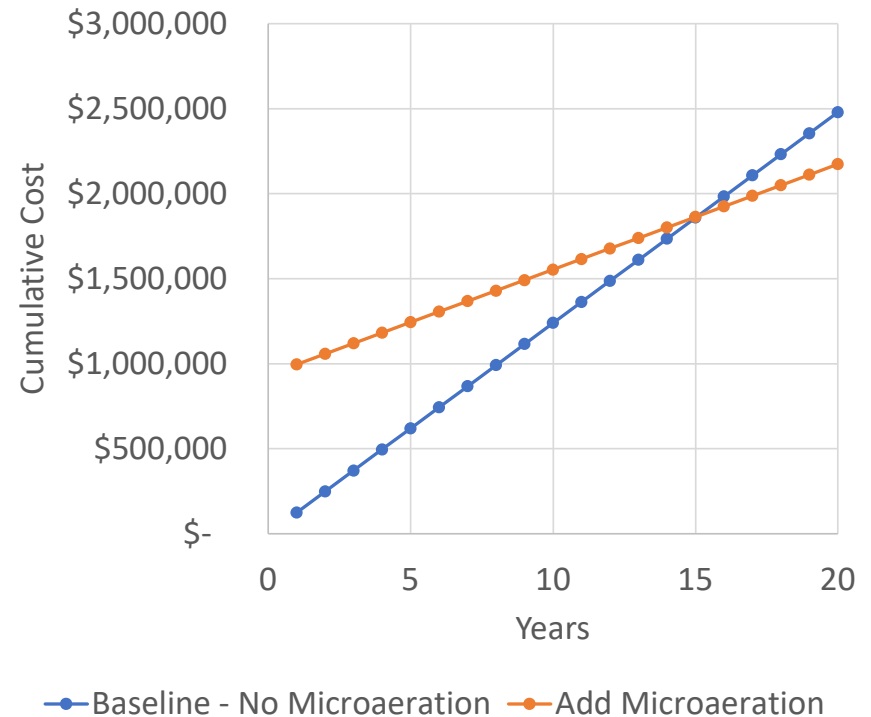
Microaeration for H₂S Mitigation BCE

■ Simple Payback Estimate:

H2S Reduction	Payback
50%	15 years
60%	13 years
70%	11 years
80%	10 years

■ Other benefits of MA:

- Could improve solids dewaterability
- Has shown to improve digestion process reliability (including reducing foaming potential)



Non-Monetary Criteria

Non-Monetary Criteria

Drivers/ Evaluation Criteria	Weight	Maximum Possible Score	Baseline Option: 3 Mesophilic Digesters	Option 1a: Renewable Electricity Commodity Value + Incentives	Option 2a: Renewable Natural Gas Commodity Value + Incentives	Option 3a: Hybrid Baseload Cogen + Commodity Value of RNG + Incentives	Definitions
Reliability	25	10	7	6	7	9	Equipment reliability, equipment downtime, and consistent operation. Tendency for minimal failure resulting in downtime.
Redundancy	20	10	4	8	8	9	Digester, co-gen, gas conditioning, boilers, system redundancy.
Ease of Operation and Maintenance	15	10	8	6	7	4	Operational complexity for operation of units includes amount of training needed and number and complexity of mechanical equipment. Maintenance complexity includes quantity of parts involved and specialized equipment, training, and steps needed to perform the work.
Biosolids Quality (Class A)	10	10	3	4	4	4	Class A provides regulatory compliance surety and mitigates risk.
Biosolids Quantity (Trucking/Storage)	10	10	6	4	4	4	Storage requirements and production of greenhouse gases associated with trucking operations.
City Sustainability Goals	5	10	1	9	9	9	Meeting City sustainability goals - accepting food slurry.
Net Zero – Energy Efficiency	15	10	3	10	1	10	Ability to remain net zero in energy usage.
Non-Monetary Weighted Total Score		100	52	68	58	74	

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Thank You!



Challenging today.
Reinventing tomorrow.



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A close-up photograph of various food scraps, including orange peels, a banana peel, a red bell pepper, and other vegetable waste, illustrating the theme of food waste management.

Renewable Energy Market Assessment

Jacobs Engineering Group Inc.

City of Gresham, OR

August 15, 2022

[clean energy economy]

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1.0 Introduction

The City of Gresham (Gresham), Oregon currently operates a Wastewater Treatment Plant (WWTP) that produces biogas from the anaerobic digestion of biosolids and fats, oils, and greases (FOG). The biogas is converted into electricity and heat, which is then used for on-site power and heating needs. Excess electricity is fed into the Portland General Electric (PGE) electrical grid. Gresham is currently seeking to expand its facility to accept additional biosolids and FOG, as well as food waste that will be diverted from landfills by the Metro Commercial Food Scraps Policy. In recent years, the volume of high-value renewable natural gas (RNG) entering renewable energy markets has steadily increased, and with the competitive pricing of RNG within these markets, Gresham is considering upgrading biogas to RNG. Gresham would like a deeper understanding of renewable energy markets and the potential revenue generation opportunities available for continuing to produce electricity or upgrading its facility to produce RNG.

The goal of this renewable energy market assessment is to outline the current markets available for renewable electricity and RNG, analyze current conditions in each market, outline the pros and cons associated with each market, and discuss emerging markets. The primary goals of this assessment are to:

1. Provide regulatory landscape and background of the following programs:
 - a. Federal Renewable Fuel Standard (RFS)
 - b. California Low Carbon Fuel Standard (CA-LCFS)
 - c. Oregon Clean Fuel Program (CFP)
 - d. British Columbia Low Carbon Fuel Standard (BC-LCFS)
 - e. Non-Transportation and Voluntary Markets
 - f. Other Developing Markets
2. Outline current market conditions and the future of each of the programs listed above.
3. Analyze the pros, cons, and risks associated with each of the markets listed above.
4. Provide unit pricing information for each renewable product under each market.
5. Detail emerging markets.
6. List carbon intensity (CI) optimization strategies.

1.1 Renewable Electricity

Gresham currently uses electricity produced from the anaerobic digestion of waste along with solar panels installed on-site to power its facility operations, including two internal combustion engines. Heat from the internal combustion engines is used to heat the digesters, administration building, solids building, lower headworks, and thickener building. When surplus power is generated, it is fed into PGE's electrical grid. With the planned expansion, Gresham will have the capacity to produce additional electricity, which can be sold into renewable energy markets such as California's Low Carbon Fuel Standard (LCFS) or Oregon's Clean Fuels Program (CFP), with future potential to be sold into the Federal Renewable Fuel Standard (RFS). Renewable energy markets available for participation will be discussed in later sections of this report.

Gresham also has the option to provide excess process energy to PGE Net Metering¹. Net metering involves the use of a bidirectional meter, which measures power flow both to and from the electrical grid. Customers can gain kWh credits if they generate more electricity than they consume. At the end of the

¹https://assets.ctfassets.net/416ywc1laqmd/6VdgcRq1GjVQlaOdRGuhm3/e2133ac5adfe3ea0ae3ab36f9f6982/sched_203.pdf

last billing cycle, any excess kWh credits are transferred from the customer's account to PGE's low-income assistance program.

PGE also offers the option to participate in their Dispatchable Standby Generation program (DSG)². This program adds a facility's stand-by generators to PGE's reserve electrical distribution system in order to provide power when the region is in critical need. If a participant loses power at the same time PGE is using the DSG system, the participant's generators will always supply power to their own facility first. In exchange for joining DSG, PGE will do the following:

- Pay to upgrade switchgear and install control and communications hardware
- Assume most routine maintenance and operation costs
- Typically pay for fuel consumed by the standby generator
- Pay for additional fuel storage, if needed
- Test system monthly under full load

Due to the program's popularity, PGE is not currently accepting new participants as of the date of this report; however, those who are still interested in joining may join a waiting list.

1.2 Renewable Natural Gas

Biogas from food scraps, FOG, and biosolids can be upgraded to "pipeline-quality" RNG and injected into a distribution system to be used for transportation fuel. "Pipeline-quality" RNG means the upgraded RNG must meet the gas specifications and minimum standards required by a commercial pipeline company. To achieve pipeline quality RNG, most of the non-methane components must be removed. By removing the non-methane components, a methane rich gas will be achieved. Currently, Gresham uses biogas for the purpose of electricity production. A biogas upgrading system will need to be installed in order to produce RNG that meets the minimum quality standards for pipeline injection.

The four most common technologies used for a biogas upgrading system, are pressure swing adsorption (PSA), membrane filtration, water scrubbing, and chemical scrubbing. If Gresham pursues the option of RNG production, it is important to have a baseline understanding of the additional equipment necessary to produce pipeline-quality RNG.

² <https://portlandgeneral.com/save-money/save-money-business/dispatchable-standby-generators>

2.0 Market Overview

2.1 Federal Renewable Fuel Standard

2.1.1 Regulatory Landscape

The United States Renewable Fuel Standard (RFS) was passed by Congress in 2005 as part of the Energy Policy Act (EPAct). The RFS required that all transportation fuel commercially sold in the United States must contain minimum volumes of renewable fuels to replace or reduce petroleum-based fuel. USEPA's definition of a renewable fuel is *"...liquid and gaseous fuels and electricity derived from renewable biomass energy sources. To qualify for the RFS program, the fuel must be intended for use as transportation fuel, heating oil or jet fuel."* The EPAct was expanded and extended by the Energy Independence and Security Act (EISA) of 2007, which proposed a schedule for an increasing volume of renewable fuels to be blended with transportation fuels each year until 2022. At that point, 20% of all transportation fuels must come from renewable sources. Table 1 outlines a list of common terms and definitions used in the RFS.

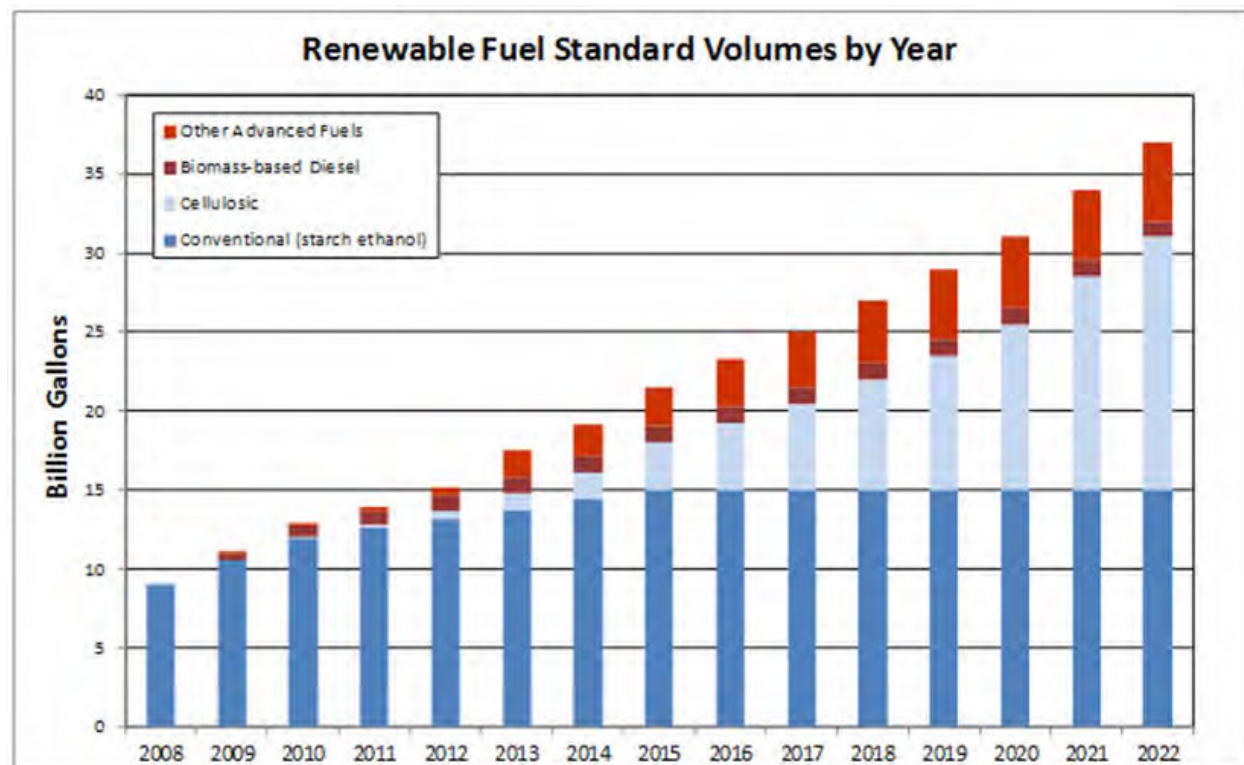
Table 1: Key Terms and Definitions for RFS

Terms	Definitions
USEPA	United States Environmental Protection Agency: Federal agency that sets and enforces the RFS
RFS	Renewable Fuel Standard: Federal program under 40 CFR 80 Subpart M, sets goal of 36 billion gallons of renewable transportation fuel by 2022
RVO	Renewable Volume Obligation: Each obligated party is obligated to meet its RVO by demonstrating that it has retired a sufficient number of RINs to satisfy its obligation
RIN	Renewable Identification Number: A unique number generated to represent a volume of renewable fuel; the "currency" of the RFS
EMTS	USEPA-Moderated Transaction System: Online system for completing all RIN transactions under the RFS
GHG	Greenhouse Gases: These gases have potential to warm the atmosphere
D-Code	Code assigned to RINs generated from renewable fuel: The D-code used must be specified in Table 1 (§80.1426), which corresponds to the pathway that describes the producers' operations
QAP	Quality Assurance Plan: The list of elements checked to verify that RINs generated are valid; designates RINs as Q-RINs if in compliance under a QAP
CDX	Central Data Exchange: The USEPA's electronic reporting and registration site
Part 79	Registration under the Fuel and Fuel Additive Registration (FFARS): Required for liquid fuels

Part 80	Registration under 40 CFR 1450: Includes the specific pathway and fuel type; requires an independent third-party engineering review and CDX Registration
Obligated Parties	Any refiner that produces or imports gasoline or diesel fuel: An obligated party is required to demonstrate that it has satisfied all RVO requirements

Figure 1 shows the original volume requirements for each renewable fuel category by year. Although this schedule was established by Congress, the United States Environmental Protection Agency (USEPA) determines a specific renewable volume obligation (RVO) annually. The RVO is the actual, total volume of renewable fuels that must be blended into the transportation sector during a given year. Each year, the USEPA must set the RVOs for cellulosic renewable fuels lower than the congressional mandate because the available supply of cellulosic renewable fuels is lower than the original mandate.

Figure 1: Renewable Fuel Production by Year



Source: <https://afdc.energy.gov/laws/RFS>

Renewable fuel production has not grown fast enough to meet the goals of the program and the 20% renewable fuel usage by 2022 statutory requirement will not be met. The regulation allows USEPA to lower annual RVO levels to meet industry production. In 2020, the statutory requirement for overall renewable fuel production was 31 billion gallons. However, the actual RVO set by USEPA for 2020 was 17.13 billion gallons. This is due to the lack of industry production, primarily in the cellulosic fuel category as outlined above in Figure 1. At the end of 2021, the USEPA sent proposed RVO volumes for 2021 and

2022 to the White House Office of Management and Budget (OMB). On June 3, 2022, the USEPA released the finalized RVO schedule for 2020-2022. The final volume requirements for 2020, 2021, and 2022 are shown below.

Final Volume Requirements for 2020-2022 (billion gallons)

	2020	2021	2022
Cellulosic Biofuel	0.51	0.56	0.63
Biomass-Based Diesel	2.43**	2.43**	2.76
Advanced Biofuel	4.63	5.05	5.63
Total Renewable Fuel	17.13	18.84	20.63
Supplemental Standard	n/a	n/a	0.25

Each gallon of renewable fuel under the RFS is eligible to generate credits or “Renewable Identification Numbers” (RINs). RINs are the currency of the RFS and are used by obligated parties as a compliance mechanism to meet the annual RVO mandate. “Obligated parties” are petroleum refiners and importers of refined fuel into the United States. Obligated parties can obtain RINs by producing renewable fuels that qualify for RINs, purchasing renewable fuels with RINs attached, or purchasing RINs that have been separated from renewable fuels from projects. RINs are classified by fuel types such as biodiesel, ethanol, natural gas, and other approved renewable fuels. RIN classifications are further broken down according to the type of feedstock and processes used to create those fuels, along with the calculated reduction of greenhouse gas (GHG). These classifications are called D-Codes, as shown in Table 2.

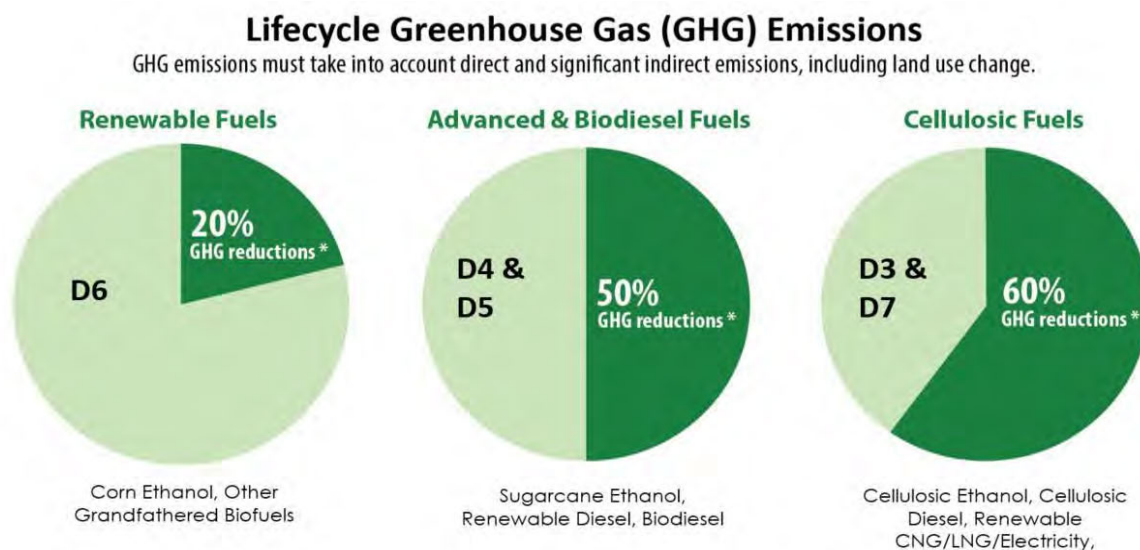
Table 2: D-Code Types

D-Code Type	Definition
D6 (Renewable Fuel)	Fuel produced in new facilities or new capacity expansions (commenced constructed after Dec. 19, 2007) must reduce life cycle greenhouse gas emissions by at least 20%. D6 RIN production is mostly from starch-based ethanol.
D5 (Advanced Biofuel)	Must reduce life cycle greenhouse gas emissions by at least 50%; compared to the petroleum baseline. RNG produced from non-cellulosic feedstocks falls into the D5 RIN category.
D4 (Biomass-based Diesel)	Must reduce life cycle greenhouse gas emissions by at least 50%; compared to the diesel baseline.

<p>D3 or D7 (Cellulosic Biofuel)</p>	<p>Must reduce life cycle greenhouse gas emissions by at least 60%; compared to the petroleum baseline and be produced from cellulose, hemicellulose, or lignin. RNG produced from cellulosic feedstocks falls into the D3 RIN category.</p> <p>To be eligible for D-Code 7 RINs the fuel must be cellulosic diesel.</p>
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Figure 3 shows the various categories of renewable fuels, minimum GHG reduction expected, and associated D-Codes. To determine the GHG reduction of each fuel type listed in Figure 3, the USEPA conducts a lifecycle analysis based on the feedstock, production process, and fuel type produced. This is referred as a “pathway for renewable fuel.”

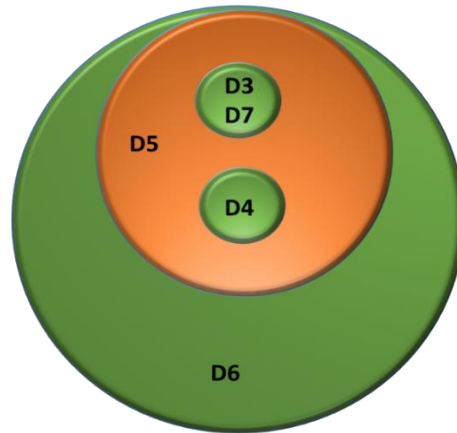
Figure 3: Greenhouse Gas Emission by Fuel Type



Source: <https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard>

As shown in Figure 4, RINs have a nested structure. This means that cellulosic D3 and D7 RINs can satisfy cellulosic, advanced, or renewable fuel RVOs. D7 RINs can be used instead of a D3 RIN to satisfy the cellulosic fuel RVO, but since D7 RINs are not often produced or traded, this is uncommon. The advanced renewable fuel D5 credits can satisfy the advanced or renewable RVOs but not the cellulosic RVOs. RINs must be used for compliance in the calendar year they were generated or the following calendar year. Obligated parties can use RINs from the previous year to satisfy up to 20% of the current year’s RVO. This nesting structure is why D3 RINs trade at a higher value than other RIN categories as they can meet the compliance obligation of all other RIN D-codes.

Figure 4: Nested Structure of D-Codes



Source: EcoEngineers

An obligated party is required to purchase RINs to satisfy their RVOs for each type of fuel (cellulosic biofuel, biomass-based diesel, advanced biofuel, renewable fuel). The RVOs for each type of fuel are calculated by multiplying the non-renewable gasoline and non-renewable diesel produced or imported by a percentage set by the USEPA. An example equation for cellulosic biofuel is shown below.

$$RVO^{CB,i} = (RFStd^{CB,i} * (GV^i + DV^i)) + DCB,^{i-1}$$

Where:

$RVO^{CB,i}$ = The Renewable Volume Obligation for cellulosic biofuel for an obligated party for calendar year i , in gallons.

$RFStd^{CB,i}$ = The standard for cellulosic biofuel for calendar year i , determined by USEPA pursuant to § 80.1405, in percent.

GV^i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (f) of this section, which is produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i , in gallons.

DV^i = The non-renewable diesel volume, determined in accordance with paragraphs (d), (e), and (f) of this section, produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i , in gallons.

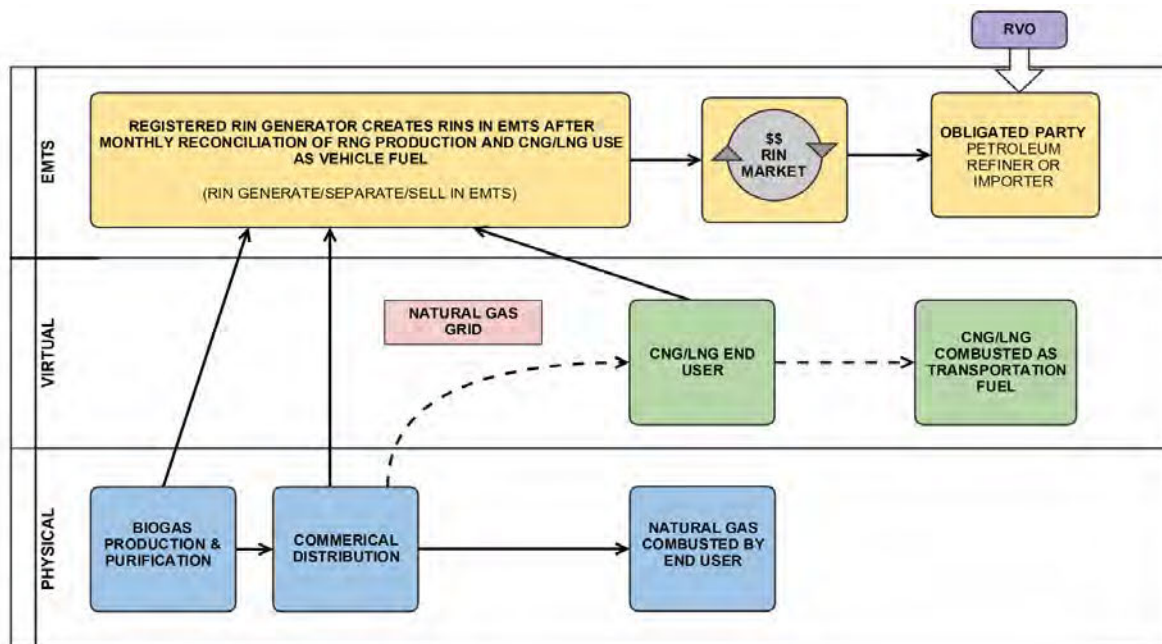
$DCB,^{i-1}$ = Deficit carryover from the previous year for cellulosic biofuel, in gallons.

An obligated party that fails to meet the yearly RVO may carry the deficit into the following calendar year. The obligated party must then meet the yearly RVO and the deficit in the following year, as the obligated party cannot carryover a deficit two years in a row.

To sell into the RFS market, the facility must be registered with the USEPA under an approved pathway. The USEPA has a list of approved pathways which are dependent on the type of feedstock, production process, and fuel type. To register the pathway under the RFS program, an independent third-party engineering review report must be provided to USEPA, which is based upon a site visit and review of relevant documents. In addition, to qualify the RINs under the RFS program registration, the project owner must demonstrate the physical and contractual pathway of the renewable fuel from production to end use as transportation fuel.

Figure 5 shows the life cycle of a RIN in the RFS program for biogas RNG. The blue boxes represent the physical fuel, the green boxes represent the fuel's end user, and the yellow boxes represent the movement of RINs in the market once they are separated from the physical fuel. Due to book-and-claim accounting, the fuel injected into the grid will not necessarily be the same fuel extracted by the end user. The dotted line represents the contractual relationship between the end user of the transportation fuel and the fuel producer. Once fuel production and end use are authenticated, RINs are generated in the EMTS system, where they can then enter the market to be bought and sold by obligated parties to meet their RVO. It is unclear how the RFS will handle credit generation from renewable electricity and who will be the primary credit generator.

Figure 5: Life Cycle of RFS RIN



2.1.2 Renewable Electricity in the RFS

Currently, the RFS program has existing approved pathways for the use of biogas to produce renewable electricity under a D3 or D5 RIN classification. There have been over 30 registrations submitted to the USEPA under these electricity pathways. However, these registrations have not been processed or approved yet by the USEPA; therefore, there is still no precedent for the generation and monetization of

electricity RINs (eRINs). EcoEngineers is anticipating an announcement from the EPA in the near future on whether they will begin to approve pathways for electric vehicle charging. It is expected that any new proposal from the EPA on this type of pathway would go out for public comment.

2.1.3 Renewable Natural Gas in the RFS

Renewable compressed natural gas (RCNG, RNG, or sometimes referred to as biomethane) produced from “non-cellulosic” feedstock can potentially qualify for D5 RINs, while RNG produced from cellulosic feedstocks can qualify for D3 RINs. Cellulosic feedstocks which qualify for D3 RINs include municipal biosolids from wastewater treatment plants, landfill gas, agricultural waste such as manure or crop residues, and separated municipal solid waste (MSW), or other feedstocks with an adjusted cellulosic content above 75%. Non-cellulosic feedstocks that qualify for D5 RINs include fats, oils, and greases (FOG), sugars, starches, most industrial high strength waste, food waste, and other feedstocks that do not contain a minimum 75% cellulosic content.

Please note the USEPA does not currently have a methodology to attribute the biogas produced to its respective feedstock. If cellulosic and non-cellulosic feedstocks are mixed and co-digested, then all biogas produced by the digester would be eligible for D5 RINs. For purposes of the unit pricing analysis provided in Section 7.0 of this report, EcoEngineers assumed a D5 RIN classification under the RFS program, but also provided D3 RIN unit pricing under current market conditions, for reference.

Biogas-to-RNG-to-pipeline injection projects have a distinct advantage over liquid renewable fuels because the RFS recognizes the principle of displacement. RNG molecules are completely fungible with the fossil natural gas molecules in the pipeline. Under the RFS program, RNG can be injected into the natural gas distribution grid anywhere in the 48 contiguous states and qualify as an eligible renewable fuel, as long as an equivalent volume of CNG is used as transportation fuel at any point along the interconnected distribution grid. This book-and-claim accounting model has made it easier for many of these RNG projects to be developed anywhere in the United States and still be able to participate in the low carbon fuel programs.

2.2 California Low Carbon Fuel Standard

2.2.1 Regulatory Landscape

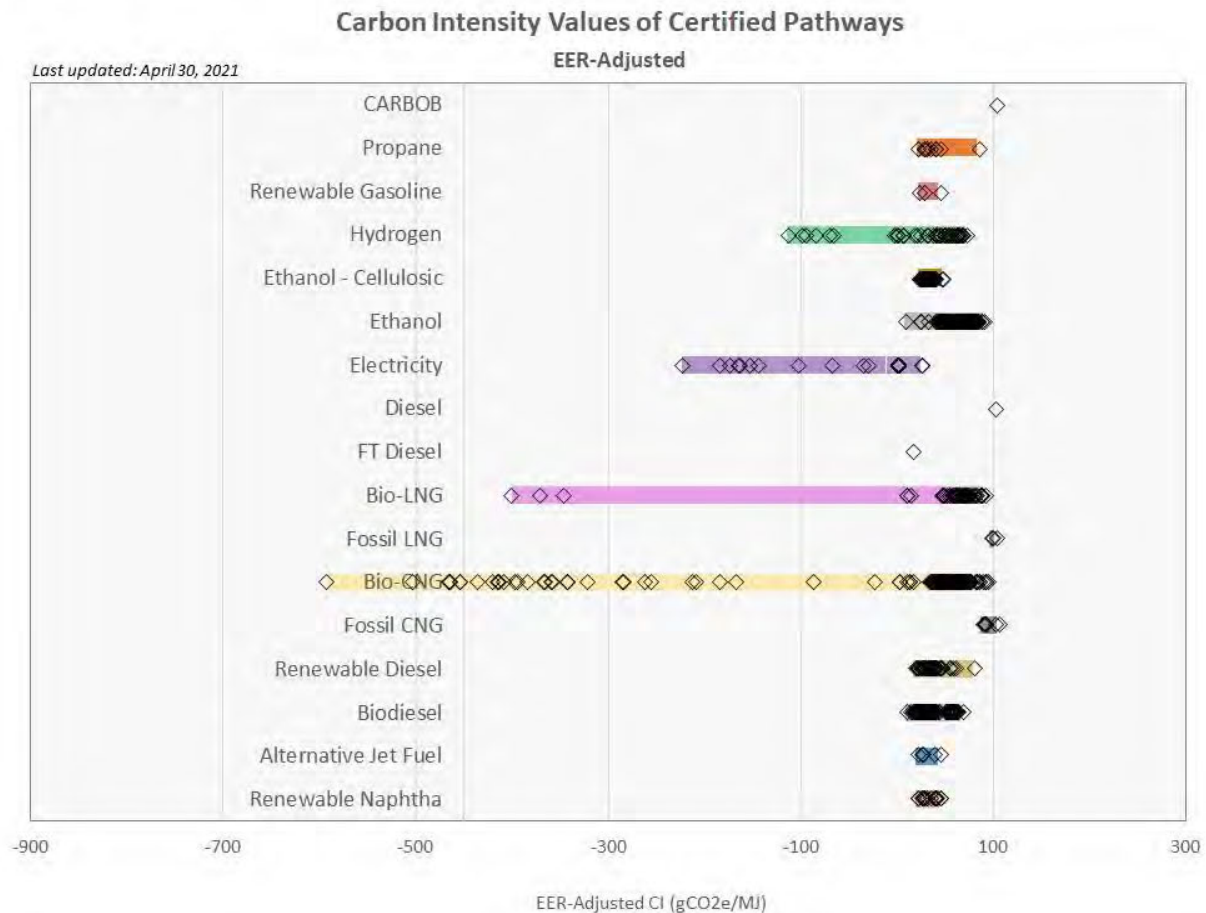
California’s Low Carbon Fuel Standard (LCFS) was originally adopted in 2007, amended in 2011, and re-adopted in 2018 as a legislative tool to incentivize and regulate carbon intensity (CI) reduction of transportation fuels within the state. The goal is to reduce the CI of transportation fuels by a minimum of 20% by 2030. The program was designed to benefit California by diversifying the pool of available renewable fuels, reducing petroleum dependency, and minimizing vehicle emissions for improved air quality. The transportation sector in California contributes 40% of total GHG emissions, 80% of nitrogen oxide (NOx) emissions, and 95% of particulate matter emissions. While the RFS designates petroleum refiners and importers as obligated parties, the CA LCFS program obligates any party that imports transportation fuel within California to comply with the regulation. Table 3 provides an organized list of common terms used in the CA LCFS and definitions for each term.

Table 3: Key Terms and Definitions for the CA LCFS

Terms	Definitions
CARB	California Air Resources Board – Established LCFS, implements program and has rule-making authority over LCFS
LCFS	Low Carbon Fuel Standard – Aims to achieve 20% reduction of CI by 2030
CI	Carbon Intensity – Amount of life cycle greenhouse gas emissions per unit of fuel energy
CA-GREET 3.0	Model used for life-cycle analysis in the LCFS program
LCFS Credit	Credits generated by fuels with a CI below the annual goal of the LCFS program
Regulated Parties	Companies that produce or import transportation fuel into California.
AFP	Alternative Fuels Pathway – Online registration system for facilities and fuel pathway applications
FPC	Fuel Pathway Code – Identification code that applies to a specific fuel pathway
LRT	LCFS Reporting Tool – Platform for quarterly and annual reporting and credit generation and transactions

One CA LCFS credit is equal to one metric ton of CO₂. The CA LCFS program awards credits based on a fuel's CI score, therefore incentivizing lower CI fuels. For example, if landfill gas derived RNG consumed in California has a CI of 45 gCO₂e/MJ and RNG produced from a municipal wastewater treatment plant has a CI of 0 gCO₂e/MJ, the RNG sourced from wastewater will generate more credits per megajoule of fuel when compared with landfill RNG. RNG produced from manure-based digesters has received the lowest CI scores of any project and fuel type with some as low as -350 gCO₂e/MJ. The CI scores assigned are facility-specific, as they are calculated based on the input and output data from that facility using CARB approved version of the GREET lifecycle analysis model. Figure 6 shows the CI values of current certified pathways within the CA LCFS program.

Figure 6: Carbon Intensity Values of Certified Pathways



Source: <https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities>

To sell into the California market, each facility must be registered with CARB. For common fuels such as gasoline, diesel, electric, or compressed fossil natural gas, facilities can use lookup table values for their registration process. Lookup table applications need to include the required supporting documentation for approval from CARB staff. For common or established fuels like starch ethanol, biodiesel, or RNG, facilities can apply for a Tier 1 pathway. Tier 1 applications must provide all required supporting documentation and then undergo in-person facility review by CARB staff or a third-party reviewer. After the review, the facility must wait for final approval from CARB staff. For fuels with innovative methods or uncommon fuels, facilities must apply for a Tier 2 pathway, which involves a more detailed review and validation process.

Companies or facilities producing hydrogen or electricity as transportation fuels can choose not to participate in the LCFS program. If companies choose to opt in and participate in the LCFS program, they must register the facility with CARB. By choosing to participate in the LCFS program, providers of electricity or hydrogen as fuel can also earn LCFS credits.

2.2.2 Carbon Intensity Score within the CA LCFS

The number of credits a fuel receives depends on its CI score relative to the carbon intensity compliance requirement, which is seen in Figure 7. Compliance curves have been established for gasoline, diesel, and jet fuel. When a fuel has a CI score lower than the established compliance curve, it generates credits. Fuels with CI scores above the compliance curve generate deficits, and those deficits need to be satisfied by LCFS credits. It is advantageous to produce fuel with a low CI score, as the fuel can generate more credits under the LCFS system.

Figure 7: LCFS Annual Compliance Curve

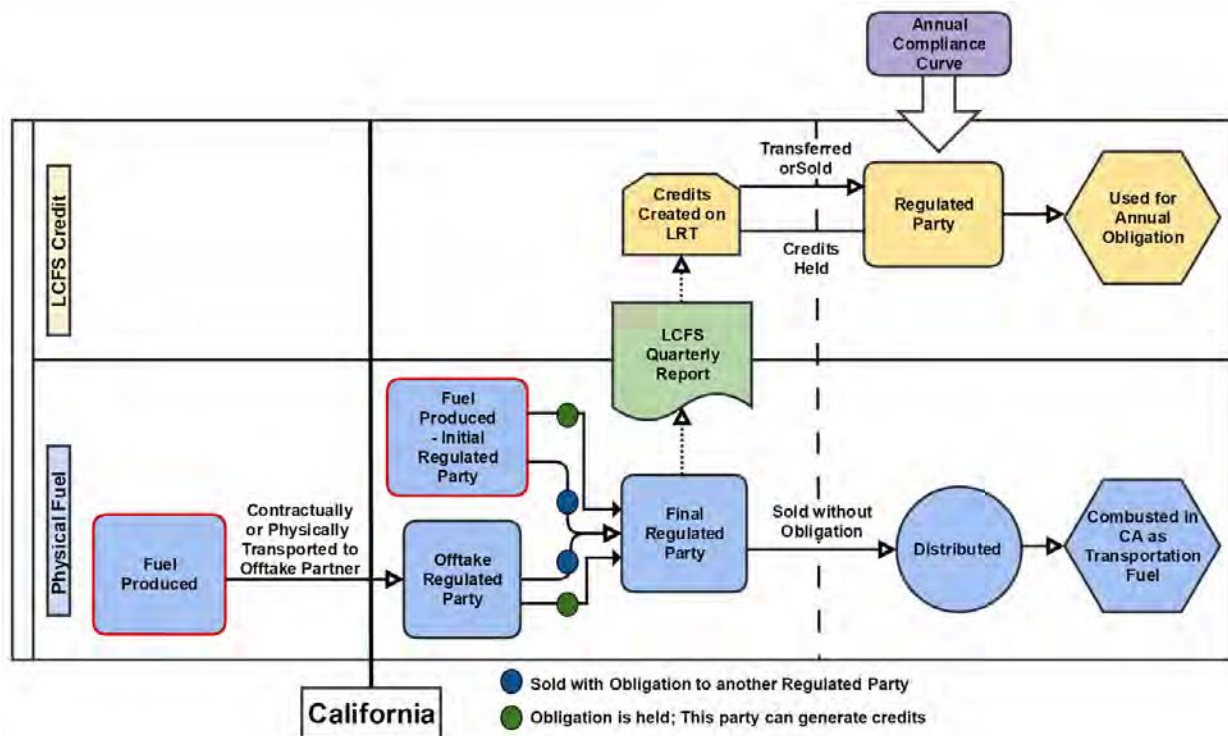


Source: EcoEngineers

Figure 8 shows the life cycle of a credit through the LCFS and CFP programs. The diagram uses LCFS terminology, however, the example below accurately represents the movement of fuel and credits within the Oregon CFP as the two programs are structured similarly. To maintain consistency with the graphic, the explanation that follows will use California and LCFS terminology.

The blue boxes represent the physical fuel while the yellow boxes represent the generation and movement of the virtual LCFS credit. The fuel is first produced either inside or outside of California. Once transported to California, it is traded or sold to the final regulated party, who will then sell the fuel to the end user. The final regulated party is responsible for demonstrating that the fuel has been used for transportation by submitting a quarterly report to LRT system, at which point credits will be generated. Regulated parties with a credit deficit can buy these credits to meet the annual CI compliance goal set by CARB.

Figure 8: Life Cycle of LCFS/CFP Credits

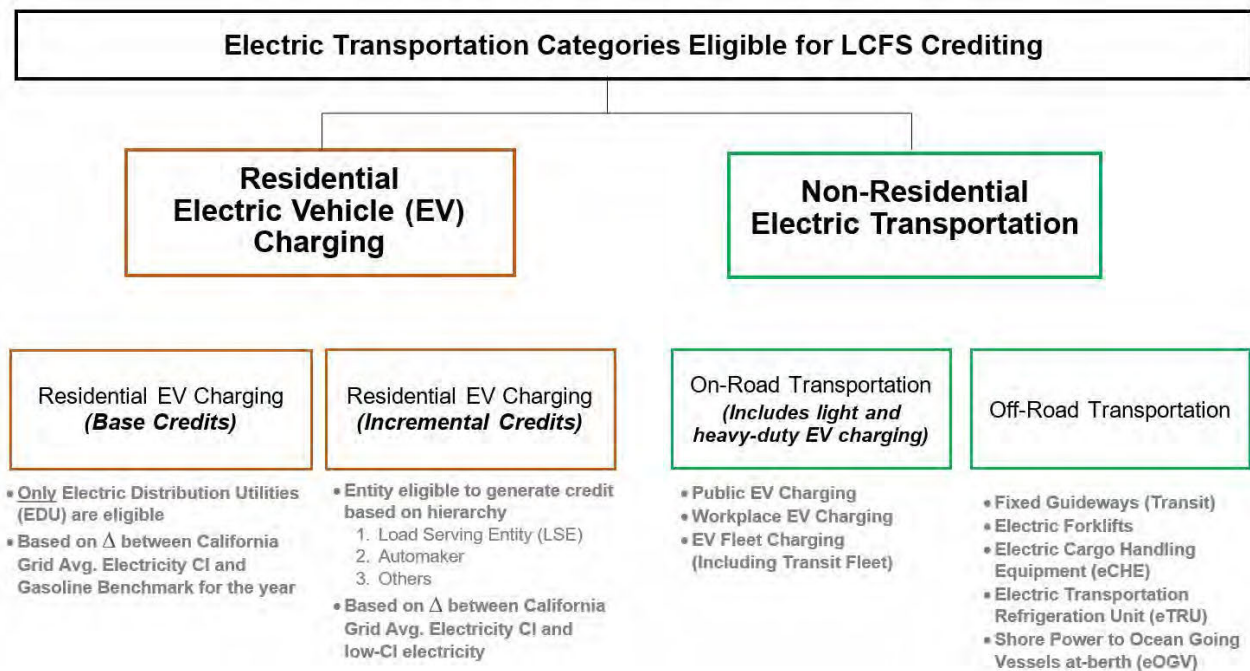


2.2.3 Renewable Electricity in the LCFS

To participate in the LCFS program with renewable electricity, the pathway application submitted may fall under a Lookup Table or Tier 2 pathway. Per the LCFS regulation, the Lookup Table application includes electricity produced from “eligible renewable energy resources as defined in California Public Utilities Code sections 399.11-399.36, excluding biomass, biomethane, geothermal, and municipal solid waste”. If Gresham produces electricity from biogas, it is likely this would fall under a Tier 2 application, which includes electricity pathways not covered under the Lookup Table pathways.

Per § 95483(c) of the LCFS regulation, there are four different categories available for credit generation for electricity used as transportation fuel, as illustrated in Figure 9. Figure 9 outlines the different transportation sectors Gresham’s renewable electricity may be used for.

Figure 9: LCFS Credit Generation Possibilities Utilizing Electricity as Transportation Fuel



Source: <https://ww2.arb.ca.gov/resources/documents/lcfs-electricity-and-hydrogen-provisions>

Since Gresham is in the Western Electricity Coordinating Council (WECC) region, Gresham has the ability to participate in the LCFS market with renewable electricity. The LCFS regulation allows for the use of the book-and-claim accounting. This accounting mechanism is a chain of custody model that allows for the ownership and transfer of transportation fuel without regard to its physical traceability. To meet the book-and-claim requirements for low-CI electricity, including zero-CI electricity, under the LCFS program, the physical electricity must be delivered to a California balancing authority. “Alternatively, to show electricity generated from an out-of-state resource was supplied to the California grid, the low-CI electricity must meet the deliverability requirements of California Public Utilities Code”³. If these requirements are met, book-and-claiming accounting may be used for the electricity quantity supplied, which must then be claimed for LCFS reporting and generation of credits within three calendar quarters.

2.2.4 Renewable Natural Gas in the LCFS

To participate in the LCFS program with renewable natural gas, the pathway application must be submitted to CARB. For RNG, this application would likely fall under a Tier 1 pathway, unless the project involves “biomethane from sources other than those listed under the Tier 1 classification” or “pathways classified as Tier 1 that are produced from innovative production methods”, per § 95488.1(d) of the LCFS regulation.

³ https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-01.pdf

For RNG, the entity with first title to the generation of LCFS credits is the entity that owns the fueling equipment used to dispense the compressed natural gas (CNG), liquified natural gas (LNG), or liquid-to-compressed natural gas (L-CNG) as transportation fuel. Alternatively, the fueling equipment owner may elect to designate another party as the credit generator, or the first fueling reporting entity, as long as both parties have contractually agreed to such set up. The fueling supply equipment (FSE) owners often will generate LCFS credits for displacing diesel fuel with fossil natural gas as transportation fuel. Typically, based on contractual terms, the FSE owner, or offtake party, will then share credit revenue back with the RNG producer only for the incremental credits for the displacement of fossil natural gas with RNG as transportation fuel.

For participation in the CA LCFS program, RNG can be injected into a commercial distribution pipeline anywhere in the United States through the use of book-and-claim accounting. Book-and-claim is a chain-of-custody model in which environmental attributes are decoupled from the physical fuel and then re-attached to an equivalent volume of fuel at another location. This provides the ability to stack RINs and CA LCFS credits. It is important to note that placement of RNG into the California market is very competitive. Currently, nearly all fuel dispensed as compressed natural gas in California is from renewable sources. New projects producing RNG must have a low CI score, zero or negative, to participate and generate CA LCFS credits. The CI score of the RNG will dictate if the RNG has a market in the LCFS program.

2.3 Oregon Clean Fuels Program

2.3.1 Regulatory Landscape

Oregon passed a bill with the aim to reduce emissions from transportation sector and promote low-emission alternative fuels. The Oregon Environmental Quality Commission proposed rules to reduce the CI of transportation fuels by 10% by 2025. The Oregon Legislature passed those rules in 2015 and fully implemented the Clean Fuels Program (CFP) in 2016. Early 2020, the Governor of Oregon issued an executive order to reduce the CI of transportation fuels by 20% by 2030 and at least 25% by 2035. The program was adopted to incentivize the use of low carbon fuels and minimize emissions from the transportation sector. Table 4 provides key terms and definitions associated with the CFP. The program closely mirrors the California LCFS program.

Table 4: Key Terms and Definitions for CFP

Terms	Definitions
OR DEQ	Oregon Department of Environmental Quality – Oversees air quality, water quality, hazardous waste, etc. in Oregon
CFP	Clean Fuels Program – Low carbon fuel standard program in Oregon with a goal of 10% reduction in GHG by 2025
OR-GREET 3.0	Life-cycle analysis model used for determining CI score of transportation fuel
Regulated Parties	Companies that produce or import transportation fuel into Oregon
CFP Credit	Credits generated by fuels with a CI below the annual goal of the CFP program
AFRS	Alternative Fuels Registration System – registration system for the Oregon CFP program

Producers of renewable fuel can submit facility specific pathway applications to the Oregon Department of Environmental Quality (DEQ) or producers with certified California LCFS pathways can register the certified pathway under the CFP. The CI score is determined through OR-GREET modelling, which is similar to CA-GREET with the transportation distance now calculated to Oregon instead of California. Fuel pathways that have been approved under the CA-GREET model can be approved in Oregon by updating the transportation distance to Oregon.

By transporting renewable fuel into Oregon, it is possible to earn both RINs and OR CFP credits. However, the fuel can only get credit from one state and cannot stack CFP and LCFS credits. The CFP offers an additional market for the fuel considering the competitive nature of the California LCFS. Renewable fuel producers can send a certain portion of fuel to the California LCFS and the remainder to the Oregon CFP. The CFP is less attractive than the California LCFS, as there is less overall demand and has historically had a lower credit value.

2.3.2 Carbon Intensity Score Importance

Similar to the CA LCFS program, the Oregon CFP program relies on the CI score of a fuel. Each type of fuel will be given a CI score with diesel and gasoline having the highest scores. DEQ will set the carbon intensity level for each fuel, and the fuel providers must comply with meeting the carbon intensity level. Listed below are the three ways you can obtain a CI score for the renewable fuel to use in the CFP:

1. If the fuel has a CI approved by CARB, the fuel producer can apply to DEQ to accept that value with modifications as needed to reflect its destination to Oregon.
2. If the fuel does not have a carbon intensity value from CARB, then the fuel producer would still prepare a pathway application around DEQ requirements and submit to DEQ for certification.
3. There are some default carbon intensity values in the rules that can be used for generic fuels.

Business that will create cleaner fuels will generate credits, while higher carbon intensity fuels will create deficits. Like the CA LCFS program, credits can be sold to those parties with deficits. The lower the CI score, the more valuable and the higher demand for the cleaner fuel.

2.3.3 Renewable Electricity in the CFP

On March 26, 2021, the Environmental Quality Commission in the state of Oregon, adopted the CFP Electricity 2021 rulemaking, its purpose being to accelerate the generation and aggregation of clean fuels credits and advance transportation electrification. Since this rulemaking is fairly new, the OR CFP continues to provide guidance over its implementation. EcoEngineers recommends Gresham to follow up with any new guidance on this OR CFP rulemaking related electricity.

The CFP has listed specific credit generators who utilize renewable electricity. These credit generators are listed below in Table 5.

Table 5: Electricity Credit Generators in the CFP Program

Types of Charging	Base Credits	Incremental Credits
Public, workplaces, fleets, and	Owner or operator of the charger	Owner of operator of the charger

multi-unit dwellings		
Transit vehicles	Transit agency	Transit agency
Forklifts, transportation refrigeration units, cargo handling equipment, ocean-going vessel shore power	Owner/operator/service provider	Owner/operator/service provider
Residential	Electric Utility	Electric Utility
	Backstop Aggregator	Incremental Aggregator

Source: <https://www.oregon.gov/deq/ghgp/Documents/cfp-IncrementalCredits.pdf>

2.3.4 Renewable Natural Gas in the CFP

Oregon is a viable market for RNG, however it is approximately one-tenth of the size of the California renewable fuels market. This makes it difficult for large projects to participate in the program due to the smaller amount of CNG dispensed within the state. The CFP program would be an alternative option for Gresham if its RNG CI score is too high for placement into the CA LCFS market. However, since the OR CFP is still a CI-based market, placement into this market will still be dependent on the CI score.

Similar to the CA LCFS program, book-and-claim accounting may be used, allowing for the environmental attributes to be decoupled from the physical RNG molecule and then re-attached to an equivalent volume of natural gas dispensed as transportation fuel in Oregon. This provides the ability to stack RINs and OR CFP credits.

2.4 British Columbia Renewable and Low Carbon Fuel Requirements

2.4.1 Regulatory Landscape

The Renewable and Low Carbon Fuel Requirements Act was passed in April 2008 by the Legislative Assembly of British Columbia. The British Columbia Low Carbon Fuel Standard (BC-LCFS) targets a 20% reduction in greenhouse gas intensity by 2030 from transportation fuel. Table 6 lists the reduction schedule for the program.

Table 6: BC- LCFS Reduction Schedule

Compliance Period	Percentage Reduction	Carbon Intensity Limit for Diesel Class Fuel (g CO ₂ e/MJ)	Carbon Intensity Limit for Gasoline Class Fuel (g CO ₂ e/MJ)
2020	-9.1%	86.15	80.13
2021	-10.2%	85.11	79.17
2022	-11.3%	84.08	78.20
2023	-12.4%	83.04	77.24
2024	-13.5%	82.01	76.28

2025	-14.5%	80.98	75.32
2026	-15.6%	79.94	74.36
2027	-16.7%	78.91	73.40
2028	-17.8%	77.88	72.44
2029	-18.9%	76.84	71.47
2030 and subsequent compliance periods	-20%	75.81	70.51

Source: <https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels/fuel-supplier-compliance-50005>

Regulated parties under the BC-LCFS are any seller or importer of diesel, gasoline, any transportation fuel that can be blended with petroleum-based fuels, CNG, hydrogen, and electricity. The BC-LCFS allows regulated parties to be flexible when choosing their compliance method. Regulated parties can choose the lowest cost option between reducing the carbon content of the fuel, switching technologies to lower carbon alternatives, purchasing available credits, or using previously banked credits.

When selling renewable fuel into British Columbia from the U.S., the environmental attribute value can only come from the BC-LCFS credits, as RINs cannot be generated for fuels sold outside of the U.S. The BC-LCFS is less attractive for producers because of the lost revenue from not generating RINs and credits.

2.4.2 Carbon Intensity Score Importance

Like the California LCFS and the OR CFP programs, the BC-LCFS sets a CI limit and generates credits or deficits for fuels with a higher or lower CI scores than the compliance curve. Producers of renewable fuels can sell into British Columbia using a preset CI score or choose to apply for a facility-specific CI score, which are generally much lower than the present value. British Columbia uses the GHGenius model to determine the CI of a fuel. GHGenius does not include indirect land use change, unlike the CA-GREET and OR-GREET models.

2.4.3 Renewable Electricity in the BC-LCFS

In 2018, renewable electricity made up 4.2% of British Columbia's low carbon fuel supply and is expected to grow with an increase of electric vehicle sales. The electricity that displaces diesel and gasoline in vehicles is considered a Part 3 fuel under the *Renewable and Low Carbon Fuel Requirements*. A Part 3 Fuel is described as a renewable energy source that is used as substitution for gasoline. Part 3 fuels rely on the CI of the fuel when generating credits. Part 3 fuels also need to follow certain requirements to maintain compliance within the BC LCFS program.

According to the BC LCFS website, electricity generation under the BC-LCFS is currently being reviewed by the Ministry. *"Credits generated from electricity supplied in 2019 will not be validated until this policy has been finalized."* BC advises checking back regularly on this matter. As a result, there are currently no approved pathways under the program for electricity. Electricity is still very much an emerging market under the BC-LCFS program, but it is a sector that is expected to grow over the next years as more electrical vehicles are used in the BC area. EcoEngineers recommends Gresham follows the electricity reporting policy review under the Renewable and Low Carbon Fuel Requirements Act. It would also be beneficial for Gresham to check the BC website for further updates.

2.4.4 Renewable RNG in the BC-LCFS

The British Columbia market continues to grow as regulations are updated to decrease the average carbon intensity of the fuels. When selling RNG into British Columbia from the US, the environmental attribute value can only come from the BC-LCFS credits, as RINs cannot be generated for fuels sold outside of the US.

2.5 Non-Transportation and Voluntary Markets

2.5.1 Overview

Currently, there is a sustained global effort to explore how anthropogenic greenhouse gas (GHG) emissions can be reduced to levels that will limit the increase of mean surface temperature to less than 2 degrees Celsius (°C), as displayed by the overarching objective of the Paris Climate Accord. Many U.S. states, cities, and private corporations have committed to decarbonize their operations to align themselves with this global movement, either by participating in voluntary programs or by enacting policies that require industries to offset a portion of their carbon emissions.

For producers who are not eligible for D3 RINs under the RFS or with a CI score too high to enter the LCFS or CFP markets, the voluntary or non-transportation marketplaces are a strong option. Displacing fossil natural gas with renewable natural gas or using electricity sourced from renewables is one way of many to accomplish voluntary or mandatory carbon reduction goals. For example, the state of North Carolina has mandated that a portion of the natural gas purchased by Duke Energy must be RNG from swine manure. Therefore, Duke Energy will purchase RNG produced from swine manure at a premium price to satisfy this mandate. In this case, the swine farm project will be monetizing their RNG via the non-transportation market, rather than through regulatory transportation markets.

According to a 2016 report published by Advanced Energy Economy (AEE), 71 Fortune 100 companies and 215 Fortune 500 companies (43%) have a sustainability target, renewable energy target, or both. Of these, 22 have committed to get 100% of their electricity needs from renewable energy. These companies are willing to deploy their capital to finance renewable energy projects and site their operations in regions that can help them achieve their goals. The 22 companies that have a 100% renewable energy target include Apple, Microsoft, Facebook, Amazon, and Alphabet (formerly Google) - technology companies with strong data storage needs.

2.5.2 Renewable Electricity in Non-Transportation and Voluntary Markets

The conversion of the energy demand of the Fortune 500 companies from fossil fuels to renewables will accelerate the transformation of the global energy market and aid the transition to a low carbon economy, according to the RE100 website⁴. RE100 is a gathering place for companies all over the world that are committed to a transition to 100% renewable electricity use by a specific year. RE100 is comprised of over 300 companies worldwide, including large multinational corporations such as IKEA, Anheuser-Busch, Adobe, Bank of America, Apple, Nestle, Nike, Starbucks, and Walmart.

The renewable electricity market is comprised of entities that generate and purchase renewable electricity certificates, or RECs. Similar to RINs, RECs represent the environmental attributes associated

⁴ <https://www.there100.org/>

with the renewable electricity produced. Per the USEPA, RECs “...represent proof of renewable electricity delivered to the grid and represent the environmental effect of that renewable electricity to reduce the average grid emissions near the project that produced the RECs...”⁵. One MWh of electricity is equal to one REC. Depending on the contractual agreement between parties, RECs are generated, retained, and sold into renewable electricity markets by project developers, owners, or utility companies being supplied with the renewable electricity.⁶

RECs can be sold to voluntary buyers to satisfy an entity’s own carbon reduction goals, or they can be sold within non-transportation markets to meet compliance mandates set by national, state, or municipal governments. Voluntary markets consist of consumers or corporations seeking to buy renewable electricity due to emissions reduction targets or the personal desire to support the renewable energy market. Prices for RECs within the voluntary market are highly dependent on volume, length of contract, location, generation source, and date of RECs. Non-transportation regulatory markets are generally brought about by governing bodies having Renewable Portfolio Standards (RPS), which require utilities to either generate renewable electricity themselves or purchase RECs. RECs that meet a state’s RPS requirements are usually more expensive than those sold on voluntary markets. The price variation for non-transportation markets depends heavily on the specific governing body’s policies.

2.5.3 Renewable Natural Gas in Non-Transportation and Voluntary Markets

Utility companies have also shown more interest in purchasing RNG in the recent years. As a result, RNG is becoming a larger component in the utility sector, as utility companies become open to this source of supply. Currently, it is common for utility companies to purchase RNG from producers, providing another potential avenue for a fixed price agreement for RNG producers. In addition, there are some states in the United States that are moving towards requiring utility companies to purchase RNG as part of the state’s sustainability goals. This interest and participation from utility companies will continue to push the voluntary market forward.

While RNG value in the voluntary market is not typically as lucrative as generating D3 RINs or LCFS credits, the voluntary market may provide more pricing stability and, at times, longer contract term lengths. For example, a utility, university, or Fortune 100 company may commit to purchasing RNG for a fixed price for 5-, 10-, or 20-year terms. This removes the regulatory risk and pricing variability of the transportation fuel markets.

⁵<https://www.epa.gov/green-power-markets/green-power-pricing>

⁶ <https://www.epa.gov/green-power-markets/renewable-energy-certificates-recs>

3.0 Market Conditions

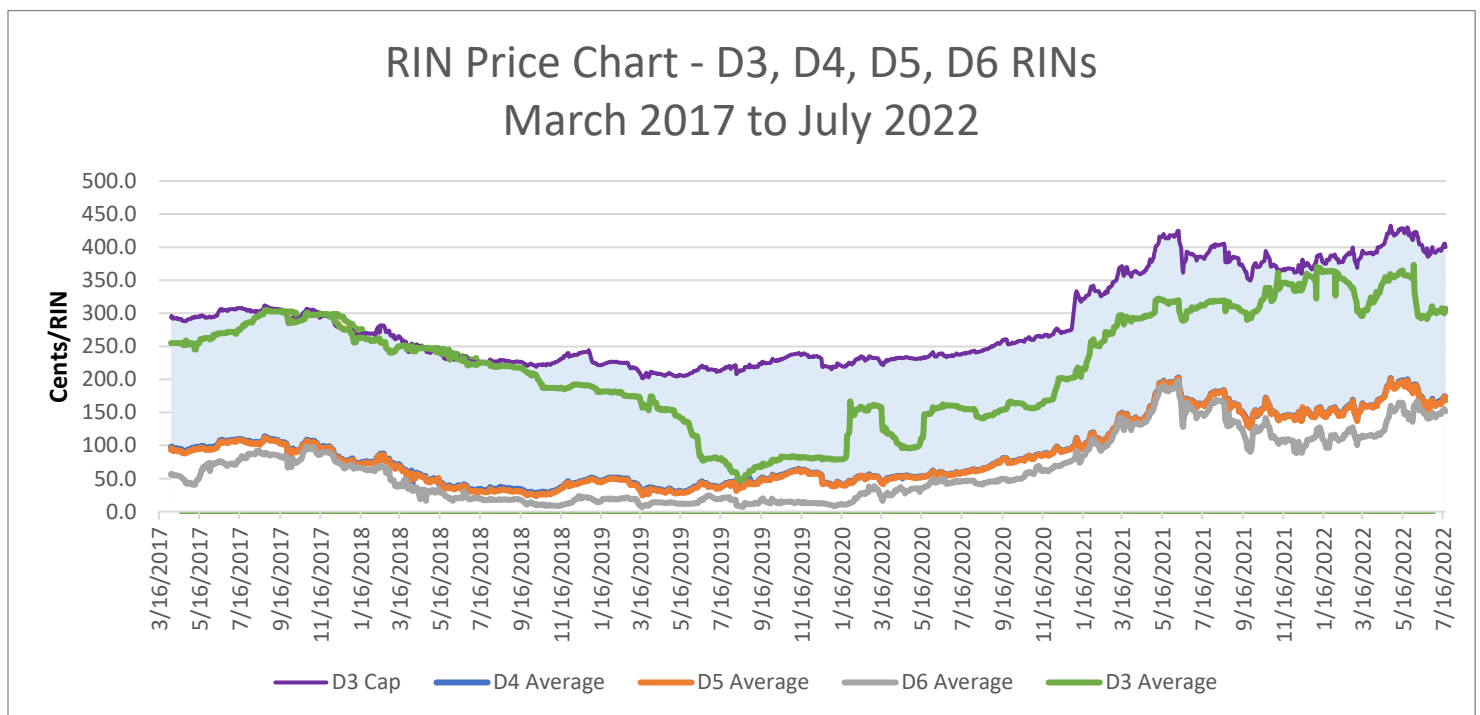
3.0 Introduction

The Renewable Fuel Standard (RFS), California Low Carbon Fuel Standard (LCFS), Oregon Clean Fuels Program (CFP), British Columbia Low Carbon Standard (BC-LCFS), and non-transportation and voluntary markets all have dynamics that affect the price and sale of renewable energy. This section provides information on each marketplace and important factors that affect credit prices.

3.1 Federal Renewable Fuel Standard Market Analysis

The RIN market moves up and down due to a variety of factors including supply and demand considerations, general market forces, political forces, and decisions by the USEPA on how to implement the program. The largest factor in RIN pricing is the annual RVOs set by the USEPA. This sets the overall market for the number of RINs which must be purchased and used for compliance obligations. Another critical factor is the number of RINs generated by the industry. Other factors include the number of Small Refinery Exemptions (SREs) approved by the USEPA. SREs are essentially waivers issued by USEPA for obligated parties that demonstrate complying with RFS regulation will cause significant financial hardship. Under the Trump administration, USEPA granted a larger number of SREs annually which eroded the overall volume of RINs that must be purchased by obligated parties. As a result, RIN prices decreased in the last few years. Recently, USEPA and Congress have intervened, and it is likely that a lower number of SREs will be issued in future years. USEPA proposals, changes in administration staff and rulemaking, and other regulatory events can shift prices. Figure 11 shows a graph of the RIN prices and how key events can cause shifts in the price of RINs. As seen in Figure 11, seemingly minor events such as meetings at the White House and statements by members of Congress and the USEPA can result in short-term shifts in RIN prices.

Figure 11: RIN Price History



Source: EcoEngineers

As shown in Figure 11, the RIN market is prone to large fluctuations and is vulnerable to political events and related policy updates. A common question is why D3 RIN prices dropped from approximately \$3.00/RIN in early 2017 to around \$.60/RIN in 2019. The main factors that contributed to this decrease in price were:

- **Renewable Volume Obligation (RVO)**
 - The RVO is set based on the production data from the previous year and the expected projects coming online in the current year with the goal to further incentivize cellulosic fuel production. If industry production of D3 RINs outproduces the annual RVO, an oversupply of RINs will occur for the given year, causing prices to fall. Historically, the industry under-produced compared to the RVO, keeping the demand for D3 RINs high which has led to strong D3 RIN pricing. However, in 2018, the industry generated more RINs (approximately 312 million D3 RINs) compared to the 2018 RVO of 288 million D3 RINs and caused the D3 RIN price to fall. The RVO in 2020 had previously been set to 590 million D3 RINs, up from 420 million D3 RINs required by the 2019 RVO. The RVOs now proposed by the USPEA in December 2021 include reducing the 2020 RVO to 510 million D3 RINs, down from 590 million. The USEPA is also proposing to set the 2021 RVO at 620 million D3 RINs and the 2022 RVO at 770 million D3 RINs. There is lots of speculation around whether the RNG industry can meet the RVO which has caused the D3 RIN value to increase in recent months. Previously, the industry has not produced sufficient D3 RINs compared to the RVO and prices are continuing to grow and hit record highs.
- **Small Refinery Exemptions (SREs)**
 - The SREs are available to refineries that are not able to meet the obligated number of RINs if the price of compliance is too high. With a high number of SREs granted, the number of RINs needed for compliance decreases. If less SREs are granted, more RINs will need to be purchased on the market, consequently raising the RIN prices. In 2018, a record number of SRE waivers were granted allowing some obligated parties to not purchase RINs to comply with the RFS. On April 7, 2022, after a court order, the USEPA announced that it had completed a review the 2018 SRE applications and found that none of the 36 applications submitted demonstrated hardship caused by the RFS. After concluding the review, the USEPA denied all 36 applications in 2018.
- **Cellulosic Waiver Credit (CWC)**
 - The cost of the CWC is an indicator of the D3 RIN price ceiling. If a D5 RIN and a CWC combined are the maximum cost of compliance for the D3 RIN obligation, the D3 RIN will always be below the price ceiling. The CWC during 2018 was valued at \$1.99 and at \$1.80 during 2020. This indicates a lower price ceiling for D3 RINs during 2020 compared to 2017/2018. The CWC typically gets set in December of each year and is based on the wholesale price of gasoline. As gasoline prices increase, the CWC decreases and vice versa. EcoEngineers projects the 2021 CWC to be \$2.00 to \$2.20 which will increase the D3 price cap.

- COVID-19
 - The coronavirus and COVID-19 impacted D3 prices significantly. As gasoline and diesel consumption was dramatically reduced, the overall compliance obligations may decrease accordingly based on recent RVOs proposed by the USEPA. It appears the overall impact of COVID-19 may have reduced consumption of transportation fuels by 8-15% for 2020. This decreases the overall number of RINs obligated parties must purchase to comply with the RFS. However, due in large part to underproduction of renewable fuels, all RIN types are at their highest price since 2017.

When the RFS was adopted, cellulosic fuels were still largely in their infancy. Therefore, the RFS includes the ability for obligated parties to purchase cellulosic waiver credits (CWCs) as an alternate compliance mechanism should D3 RINs not be available. When obligated parties look to satisfy their RVOs for cellulosic biofuel, they can either buy D3 RINs or buy CWCs. When purchasing a CWC to meet RVOs, obligated parties must also purchase a D5 RIN due to the nested nature of the RFS program. The price of the CWC is set by the USEPA through the calculation shown in Table 7. Table 8 shows the CWC Price over the last few years. The 2022 CWC is trending towards \$2.00 - \$2.20 based on historical gasoline prices.

Table 7: Determining the Price of a CWC

Description	Formula	2020 Calculation
\$0.25 (Inflation Adjusted)	$\$0.25 \times \text{Inflation Adjustments for Year} = \text{CWC Price}$	$\$0.25 \times 1.213 = \0.30
\$3.0 (Inflation Adjusted)	$(\$3.00 \times \text{Inflation Adjustments for Year}) - \text{Wholesale Price of Gasoline} = \text{CWC Price}$	$(\$3.00 \times 1.213) - \$1.836 = \$1.803$
CWC Price for Year	Larger of the two values is selected, rounded to the nearest cent	\$1.80

Table 8: History of CWC Price

Year	CWC Price
2015	\$0.64
2016	\$1.33
2017	\$2.00
2018	\$1.96
2019	\$1.77
2020	\$1.80
2021	\$2.10 (projected)
2022	\$2.20 (projected)

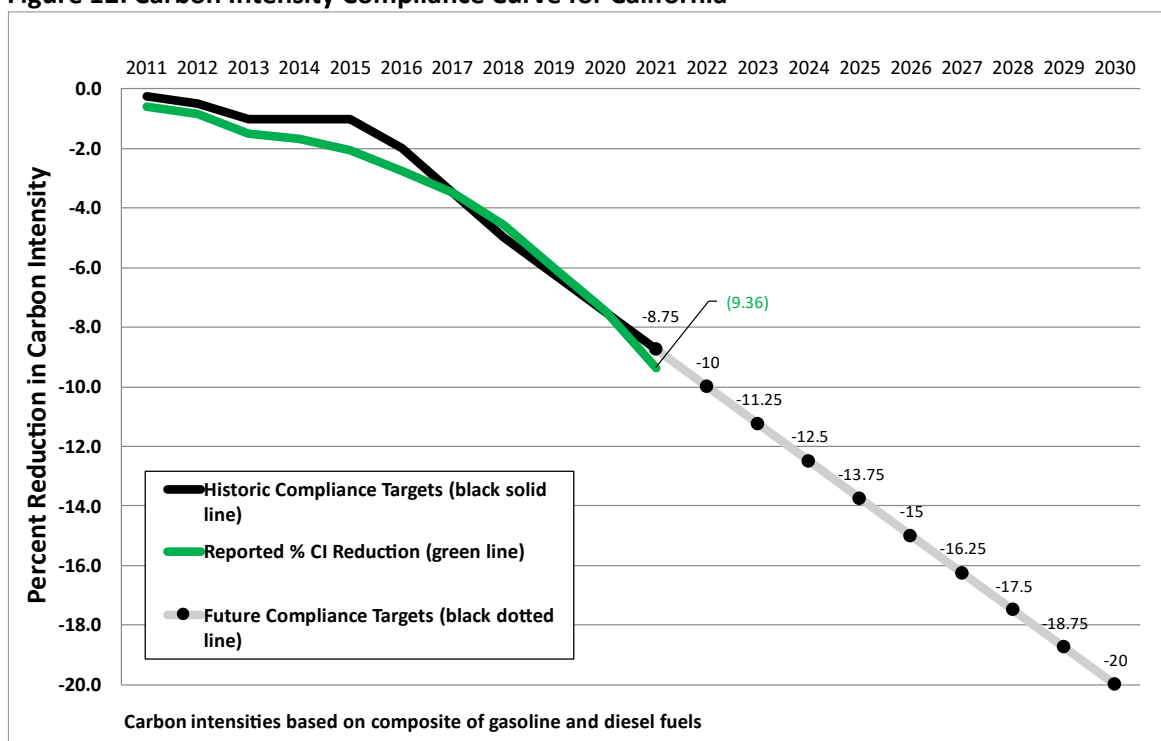
3.2 Low Carbon Fuel Standard Market Analysis

The LCFS aims to meet a 20% reduction of the GH of transportation fuels by the year 2030. To meet this goal, the LCFS has a compliance curve that sets annual CI targets, which are lowered each year. The lower

the CI of the fuel compared to the annual schedule; the more credits produced. If a fuel has a CI score higher than the compliance target, the fuel will generate LCFS credit deficits. Deficit generators must purchase credits to offset their annual deficits and retire these credits to demonstrate annual compliance to CARB. LCFS credits have no expiration date, so they can be banked and used for compliance at any later date. LCFS credits have a \$200 price ceiling, adjusted annually for inflation, but have no price floor.

The CI score of a fuel is extremely important in the LCFS market. The CI score will dictate the number of credits generated, and if there is a market for the fuel in the LCFS program. Currently the LCFS market is dominated by negative low CI RNG projects from dairy and swine manure. Figure 12 shows the historic compliance targets, future compliance targets, and the reported cumulative CI reduction of transportation fuel for each year. Based on the trend of the market, deficits will exceed credits, which will draw down the credit bank and raise prices.

Figure 12: Carbon Intensity Compliance Curve for California

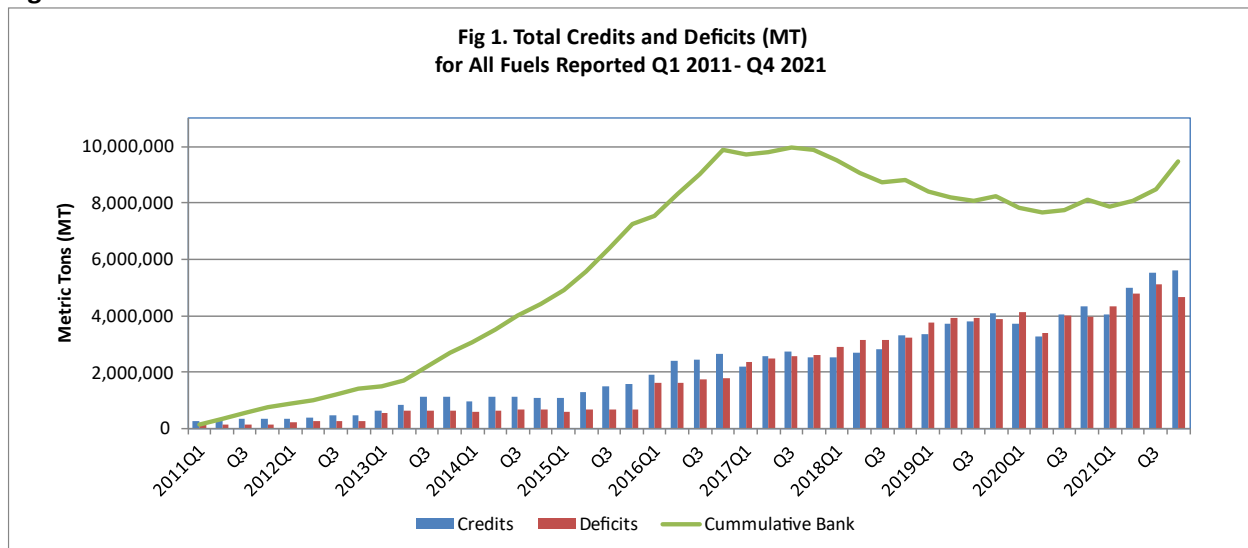


Source: <https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm>

Figure 13 shows the total debits and credits generated as well as the cumulative bank of credits since 2011. Until 2017, credit generation outpaced deficit generation and a large bank of credits was developed. The decrease in banked credits in late 2016 led to significant credit pricing increases as credit deficits began to outpace credit generation. This has continued into 2020 which is why LCFS credit prices traded near the \$200 price cap for the past two years. EcoEngineers tracks the supply of all types of renewable fuels into California. Based on the number of RNG projects in development and the development of renewable diesel, EcoEngineers believes that in the next 2-5 years that there will continue to be an oversupply of LCFS credits, leading to credit generation outpacing deficit generation and a reduction in credit prices. As seen in Figure 13, quarter 2 in 2021 began to show credits outpacing deficits, which began creating a competitive market and lowering the LCFS credit price. Throughout 2021, LCFS credits traded

at approximately \$155 to \$190 per credit, and the average price in 2022 has been \$122 with a low at \$89, compared to about \$190 to \$200 per credit in 2020.

Figure 13: Total LCFS Credits and Deficits

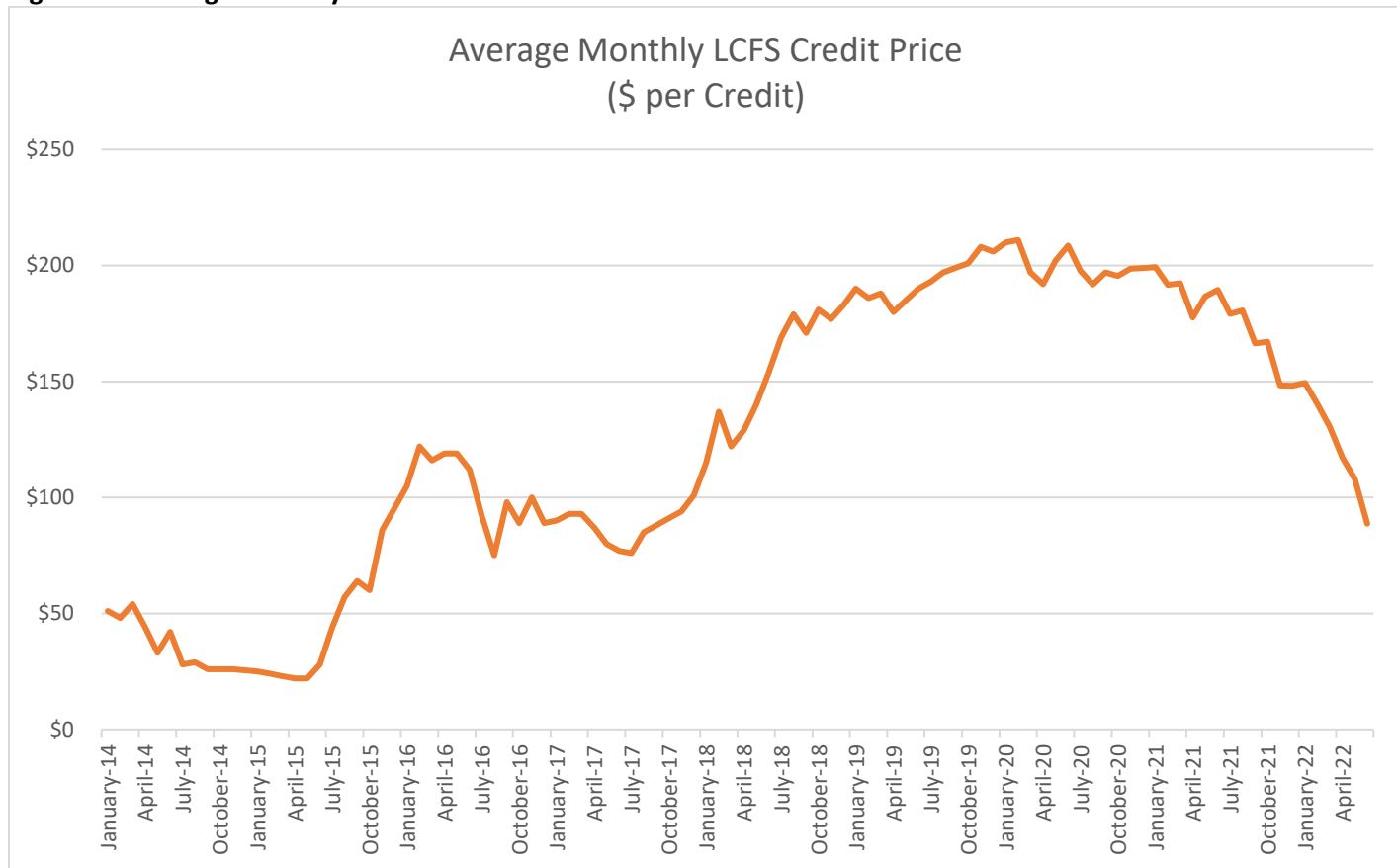


Source:

https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/dashboard/quarterlysummary/20200731_q1datasummary.pdf

Figure 14 shows the historical average monthly price of LCFS credits. Within the last month, LCFS credit prices have dropped to approximately \$80-90. This most recent decrease in credit prices is mainly due to credit generation outpacing the deficit generation.

Figure 14: Average Monthly LCFS Credit Price



Source: EcoEngineers

With the increase in credit generation, which is creating a more competitive market, more importance is placed on reducing the CI score in order to generate more credits. For example, Table 9 shows the total credits generated based off the CI score of RNG and the 2021 compliance curve. The table also illustrates the total value of the credits, or value per MMBtu, based on the number of credits and the market value of credits.

Table 9: CI Score Impact on Credit Generation

CNG Compliance Year	RNG CI Under LCFS	RNG Volume (therms)	Market Value of CI Credits	Number of LCFS Credits Generated	Total Value of Credits	\$/MMBtu
2021	-325	10,000	\$175.00	418	\$73,200	\$73.17
2021	-100	10,000	\$175.00	181	\$31,600	\$31.62
2021	0	10,000	\$175.00	75	\$13,200	\$13.16
2021	40	10,000	\$175.00	33	\$5,800	\$5.78

As shown in Table 9, the CI score determines the amount of LCFS credits generated. Depending on the fuel the RNG is substituting, the compliance curve for the original transportation fuel will change and impact the number of credits generated. For example, the fossil CNG compliance curve will generate fewer credits than the diesel compliance curve.

Because credit prices in the LCFS program are trading at a historically low price, the marketplace is very competitive, favoring low or ultra-low CI fuels, especially with RNG and electricity. RNG fuels with a positive CI score will have a hard time finding placement into California due to the current market saturation of RNG entering California. Renewable electricity with a positive CI may also have a hard time finding placement into California due to wind and solar taking priority for offtake contracts. In addition, renewable electricity projects still need to physically deliver the energy within the WECC region to be able to participate in the program and use book-and-claim accounting.

If positive CI score projects are placed into California, it may only be possible for approximately 1-3 years, or projects may have to give up 40-60% of LCFS revenue to the offtake party. Projects with negative CI scores will have an easier time finding placement for longer terms and can typically retain a higher percentage of the LCFS credit value.

3.3 Oregon Clean Fuel Program Market Analysis

The Clean Fuels Program is an important part in the state's plan to reduce greenhouse gas emissions from the transportation sector. Oregon is a significantly smaller market than California, has a substantially smaller population, and uses approximately 10% of the total fuel used by California.

Historically, credit generation has outpaced the debits, and the total credit bank has increased. Oregon has increasingly stringent compliance targets for carbon intensity reduction, which means deficit generation will increase year after year. Figure 15 shows the historic data of credits and deficits generated. Quarter 3 of 2020 was the first quarter where deficits outpaced credit generation, which further increased in Quarter 1 and Quarter 3 of 2021. If credit generation cannot keep pace with the increasing deficit needs, then there will be considerable demand for low carbon fuels in Oregon.

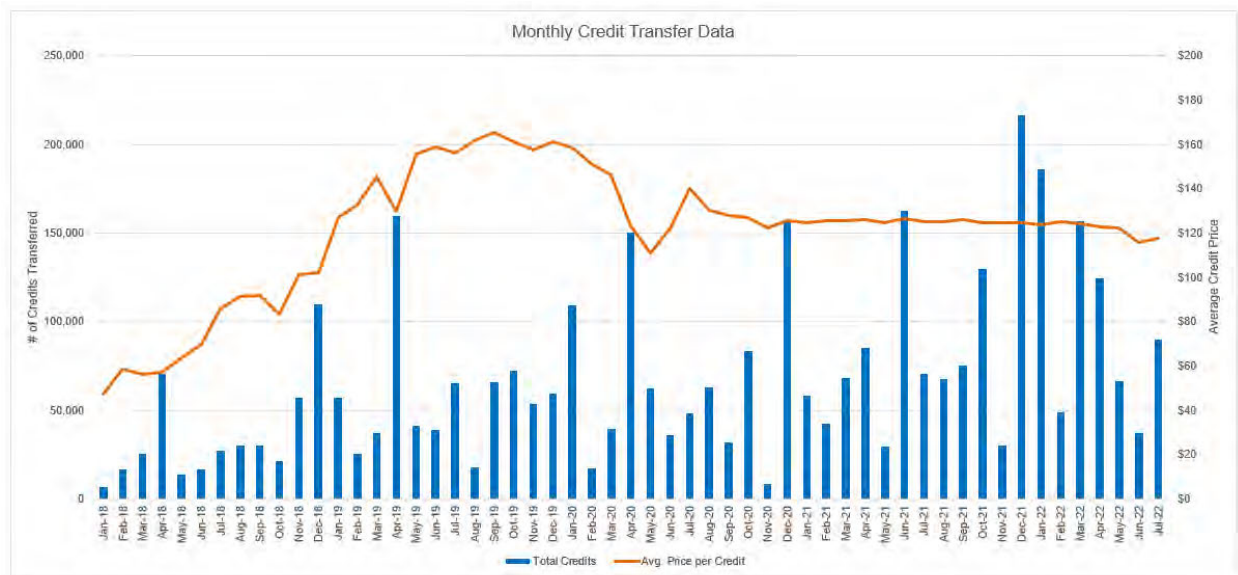
Figure 15: CFP Credits and Deficits



Source: <https://www.oregon.gov/deq/ghgp/cfp/Pages/Quarterly-Data-Summaries.aspx>

The price of CFP credits increased over 2019 to approximately \$160 per credit until a decline in March of 2020. As of July 2022, the average monthly CFP credits price was approximately \$120, as seen in Figure 16. With deficit generation increasing, the price of CFP credits may increase due to increased demand. Producers of renewable transportation fuels can take advantage of revenue from both RINs and CFP credits. Selling renewable transportation fuels into Oregon excludes the seller from LCFS credits, as only one state-level credit can be applied.

Figure 16: CFP Credit Price and Credit Volume Traded



Source: <https://www.oregon.gov/deq/ghgp/cfp/Pages/Monthly-Data.aspx>

3.4 British Columbia Low Carbon Fuel Program Market Analysis

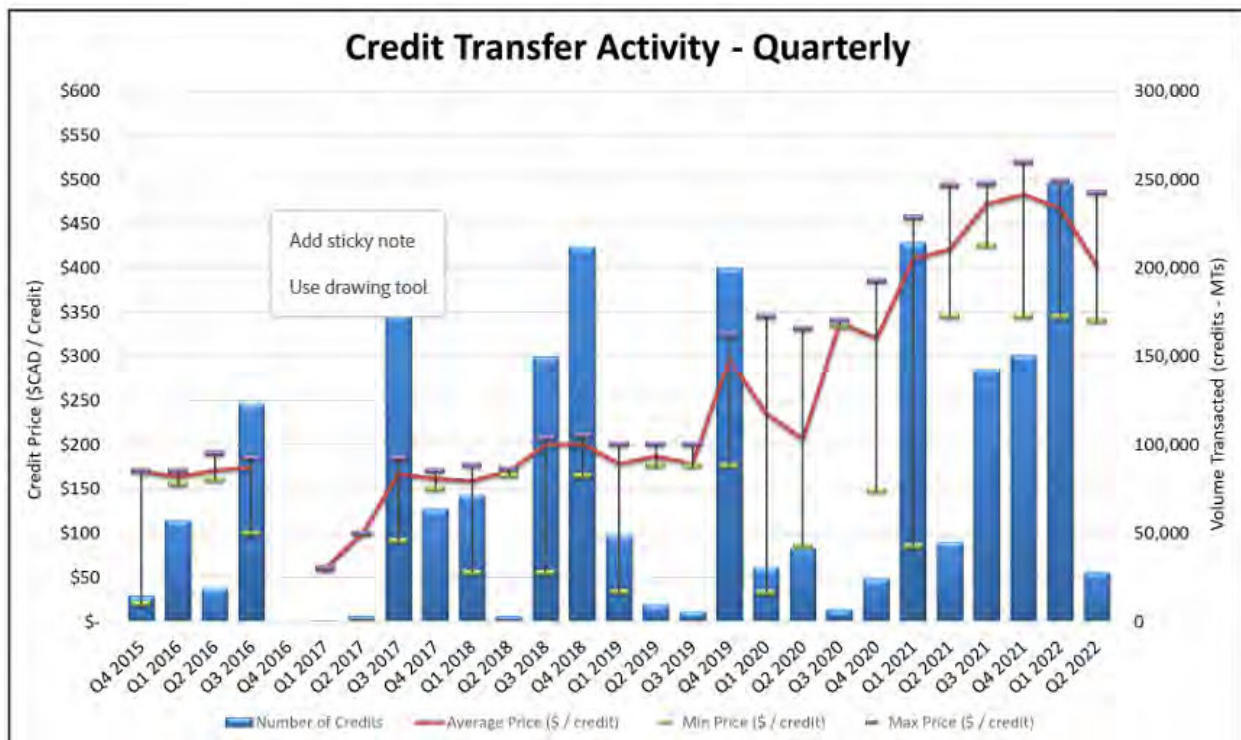
Like California and Oregon, British Columbia has implemented the Renewable and Low Carbon Fuel Requirements Regulation in an effort to reduce transportation fuel CI by 14.5% by 2025 and 20% reduction in by 2030. The British Columbia LCFS has been extremely successful in reductions in air pollution. Because of the success, the reduction schedule was updated to a more aggressive schedule. The previous schedule implemented a 15% reduction by 2030. It is important to note, British Columbia relaxed the previous 10% reduction target by 2020 slightly to 9.1%. This is to take pressure off the oil and gas sector, as it deals with significant economic impact from the COVID-19 pandemic.

When considering the BC-LCFS program, there are several differences to consider from the LCFS and CFP. Because the BC-LCFS is a Canadian program, any transportation fuel produced in the United States and exported to British Columbia is not eligible for the RFS and RIN generation. This means that any revenue for the sale of RNG in British Columbia will come from the BC-LCFS credits and the commodity price of natural gas.

The energy market is different in British Columbia when compared to California and Oregon. When looking at renewable transportation fuels produced and imported into British Columbia, the province has access to different low carbon transportation fuels. According to the Canadian National Energy Board, 95% of the electricity produced in the province is from clean or renewable sources. Having access to renewable electricity would be beneficial for producing low CI transportation fuel.

The recent Low Carbon Fuel Credit Market Report published by the British Columbia Ministry of Energy, Mines, and Petroleum Resources provides a quarterly view of all the credits transferred over the past years. During 2018, 1.8 million debits were incurred, and 1.3 million credits were generated. 2017 was the first year of the program that the debits outpaced credit generation. Since the compliance curve gets more stringent each year, this is expected to continue unless there is a large investment in developing more low-CI fuels to meet demand. In quarter 2 of 2022, the average credit price was around \$403 USD. Figure 17 shows the historical credit price and credit volume traded since 2015 in Canadian dollars. Within the last year (June 2021⁷ to June 2022⁸) the average credit price has decreased by \$19 USD.

Figure 17: BC-LCFS Credit Price and Credit Volume Traded



Source: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf017_low_carbon_fuel_credit_market_quarterly_report-july_2022.pdf

⁷ https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/monthly_credit_market_report_-_2021-06.pdf

⁸ https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/monthly_credit_market_report_-_2022-06_revised.pdf

3.5 Non-Transportation and Voluntary Markets Analysis

Many U.S. cities, states, utilities, universities, and private companies have committed to reduce carbon emissions by setting compliance goals, or in the case of governing bodies, RPS that set compliance standards for energy providers. These entities can achieve these goals by entering into long term contracts to buy renewable energy, such as electricity or RNG. Pricing is dependent on location, demand of the renewable fuel, and the prices negotiated through these fixed-fee contracts, and in the case of non-transportation compliance markets, pricing relies heavily on governing body legislature. Under these markets, entities may seek to purchase the metric tons of CO₂ equivalent, or environmental attributes, associated with renewable energy to reduce, or offset, the greenhouse (GHG) emissions generated from their own operations or from sources in relation to their activities. Alternatively, entities may choose to directly purchase both the physical molecule of the renewable energy and the associated environmental attribute to use at their facilities, while reducing overall GHG emissions.

4.0 Future of Fuel Markets

4.1 Federal Renewable Fuel Standard

While the original RFS regulation only set statutory expectations through 2022, the program will continue beyond 2022 and does not sunset or expire. However, the USEPA has yet to set annual standards for years beyond.

Actual supply has been well below the statutory demand and there is significant room for further growth in supply. Given the absence of forecasting beyond 2022, Renewable Identification Number (RIN) pricing is difficult to predict as the annual statutory target volumes have not been established by Congress or USEPA. Although the program will not expire in 2022, it is reasonable to assume that the RFS may be modified in the future to provide more regulatory and program clarity. Some of the potential changes to the program may include:

- A new methodology to establish annual RVOs post-2022. If the end result creates a greater difference between the RVO and actual production of renewable fuels, the mean price for RIN credits will increase. If RVO levels are similar to actual production levels, mean credit prices will remain steady. If RVO levels are lower than industry production, credit prices will decrease.
- Differentiating incentives may be developed for first generation, e.g., starch ethanol, biodiesel, D5 biogas, biofuels versus second generation biofuels, e.g., cellulosic ethanol, D3 biogas, resulting in higher RIN values for second generation biofuels.
- Increased coordination with state and local programs could occur. As the California LCFS and Oregon CFP programs grow and other states adopt similar programs, components of their programs may be considered for adoption to or alignment with the federal RFS program.
- Imported biofuels may become ineligible for RIN credits or reclassified to reduce the credit value of imported biofuel gallons.

4.2 California Low Carbon Fuel Standard

In 2019, the California Air Resource Board (CARB), was forced to reset the 2020 carbon intensity target due to insufficient credits generated over the prior decade. The initial CA LCFS 10% CI reduction was rolled into a new 10-year plan, and CARB set a new 20% CI reduction goal for 2030. To achieve this new CI reduction goal, supply and use of low-carbon fuels must result in sufficient credit generation in the next 10 years to result in a 20% reduction in average CI of transportation fuels.

The carbon intensity targets set by the program decrease each year. This annual decline not only results in more deficits from each Megajoule (MJ) of fossil fuel consumed, but also in fewer credits from each MJ of low-carbon fuel used as a substitute. The increasing deficits and reduction of the credit bank has caused LCFS credit prices to increase to all-time highs. At the start of 2021, the LCFS credit prices were at the maximum or close to the maximum limit set by the cost control provision of the program, providing the maximum incentive to supply low-carbon fuels to the state.

Overall, the high credit prices of the LCFS program over the past two years has spurred investment in renewable fuels. There is significant change coming in the RNG sector from the arrival of ultra-low carbon RNG from dairy/swine manure and food waste biogas projects. In 2019, about 94% of RNG consumed in California was RNG derived from landfill gas, with an average CI of 45 gCO_{2e}/MJ. However, RNG from animal manure with ultra-low CI's (-100 to -300 gCO_{2e}/MJ) is on track to be 43% California consumption by 2023. There are also 12 projects in development to produce renewable diesel which is projected to produce approximately 2.6 billion gallons. If these RNG and renewable diesel facilities come online, as well as an increase in other renewable fuels, credit generation could overcome deficit generation and cause LCFS credit prices to continue trading at a low price.

Every three to four years, CARB has provided new rule making for the LCFS program with the last being enacted at the end of 2018. In October 2020, CARB held the first public workshops outlining the new rule making process which has continued in 2021 and 2022 with a potential implementation date of January 2024. It remains to be seen what will be included in this rule making session but several key RNG issues will likely be included in the discussion including allowing other non-dairy and non-swine manures to qualify for avoided emission credits, standardizing the lagoon cleanout protocols while modeling dairy and swine projects, a transition to GREET4.0, and other RNG interests brought up by the industry.

4.3 Oregon Clean Fuels Program

The CFP program as established by the Oregon DEQ is set through 2035. The amount of pollution allowed from transportation fuels decreases annually until a 25% reduction in GHG emissions is achieved. This gives the assurance that the program will continue for the next 13 years.

From 2016 to 2020, credit generation in Oregon outpaced deficit generation and the credit bank has been steadily growing. In 2021, deficits overtook credit generation for Quarter 1 and Quarter 3. As of Quarter 4 2021, the cumulative bank of credits equaled approximately 775,000 credits. These factors have kept CFP credit prices higher than the LCFS credits, currently at approximately \$105 per credit.

Due to the decreasing GHG emissions yearly targets of the program, deficit generation has begun to outpace credit generation. As of quarter 1 2021, the cumulative bank of credits reached approximately 700,000 credits, a decrease from about 820,000 credits in quarter 4 2020. This may cause the credit prices to increase due to the higher demand of renewable fuels as a result of the larger number of deficits.

4.4 British Columbia Renewable and Low Carbon Fuel Requirements

While the BC-LCFS has had a significant impact, it was initially set through 2020. The BC-LCFS reduces GHG emissions by roughly 3,500 kilotons per year. The BC-LCFS has recently undergone review by the Ministry of Energy and Mines to review the success of the program and to determine if the cost of compliance is too high. After its review, the Ministry has extended the program to 2030 aiming to achieve a 20% reduction in the carbon intensity of its fuels. As part of the extension, the regulation relaxed the carbon reduction schedule as relief for fuel producers as part of the COVID-19 pandemic.

4.5 Non-Transportation and Voluntary Markets

There is a continuous push to decarbonize the energy consumed by everyone. Many Fortune 500 companies have taken significant steps towards low or zero carbon operations by adjusting business practices and converting to renewable energy sources, including RNG along with electricity. Many Fortune 100 companies operating energy-intensive data centers are also purchasing RNG and electricity to reduce the overall carbon footprint of the facility and the company. Numerous states and municipalities across the country have RPS programs in place, requiring utilities to either generate or buy a portion of their renewable energy. EcoEngineers expects both the voluntary markets and non-transportation regulatory markets will continue to grow as there will continue to be a demand for renewable electricity and RNG through voluntary or new mandate efforts.

5.0 Pros, Cons, and Risks

Each program has pros, cons, and risks associated with the regulation, pricing, term, compliance requirements, and other risks. Below is a summary of these for each program.

Table 10: Pros, Cons, & Risks for each Market

Pros	Cons	Risks
Renewable Fuel Standard		
<ul style="list-style-type: none"> • Relatively easy to find offtake partner for placement of gas outside of California. • Offtakers typically take a smaller revenue share than in other programs (10-15%). • Offtake terms lengths are negotiable. • RVOs typically increase year over year to promote further production of renewable fuels. • Program has been in effect for 10+ years. 	<ul style="list-style-type: none"> • The USEPA is very stringent on what qualifies as wood waste under the RFS regulation; therefore, regulatory engagement may be necessary to obtain guidance on qualification of this feedstock. • Credit prices can be volatile. • Annual RVO and SRE waivers can have large impact on prices and market dynamics can change significantly year to year. • Political events and administration of the program will vary between administrations. 	<ul style="list-style-type: none"> • There is an approved pathway for renewable electricity under the regulation; however, the USEPA has not processed and approved any of registrations submitted thus far. • Pathway Petitions take anywhere between 6 months to over a year. • Qualification of Gresham's feedstock will require engagement with the USEPA to obtain direct guidance and assurance. • RVOs are set annually by the EPA based on collected data from the industry. This can lead to volatile credit prices year over year depending on if the RVO is lower or higher. • Uncertainty around program administration with political changes within USEPA or presidential party.
California LCFS		
<ul style="list-style-type: none"> • Program is fuel neutral and any producer can participate. • Lowering CI scores lead to additional revenue. 	<ul style="list-style-type: none"> • Highly competitive marketplace that can make it difficult to place high CI fuels. • Higher CI score often leads to a higher revenue share percentage with offtake partner. 	<ul style="list-style-type: none"> • Rulemaking is evaluated every few years. This is often beneficial to projects but can lead to changes which may impact the project. • Potential for oversupply of renewable fuels as

<ul style="list-style-type: none"> • Credits can be stacked with RINs. • Program is detailed through 2030 and is politically supported within the state. 	<ul style="list-style-type: none"> • CI compliance curve decreases at a fixed rate annually. • Offtake contracts may not guarantee placement into CA for entire contract term. 	<p>most fuels produced try to enter the California market.</p> <ul style="list-style-type: none"> • Very competitive and saturated market. • Credit prices fluctuate due to political events and related policy changes.
Oregon CFP		
<ul style="list-style-type: none"> • Program offers an alternative to CA LCFS if placement into CA is difficult. • Easy to get approval for pathway if already approved in CA. 	<ul style="list-style-type: none"> • Smaller market – approximately 10% of the overall size of the CA LCFS market. • Credit price typically lower than the CA LCFS meaning lower revenue per renewable unit. • CI score-dependent market. • Less common to find offtake partner offering Oregon placement. 	<ul style="list-style-type: none"> • Finding offtake in Oregon can be difficult due to overall market size, especially for larger projects.
British Columbia BC-LCFS		
<ul style="list-style-type: none"> • Alternative to the LCFS if placement into CA or OR is difficult. • Currently, higher credit price than CA LCFS. 	<ul style="list-style-type: none"> • Cannot stack federal and state level programs (cannot participate in RFS). 	<ul style="list-style-type: none"> • BC-LCFS uses a different methodology for determining CI score than CA or OR, instead using GHGenius model.
Non-Transportation and Voluntary Markets		
<ul style="list-style-type: none"> • Strong RNG and electricity markets. • Long-term, fixed price contracts provide guaranteed revenue. • Can enter into agreement with utilities, municipalities, or universities which have a high degree of financial stability. 	<ul style="list-style-type: none"> • Credit revenue is typically less than what is achievable under the transportation markets. 	<ul style="list-style-type: none"> • Financial stability of counterparty is critical. Must assess ability to meet long term contractual obligations.

6.0 Renewable Energy Market Flow Charts

EcoEngineers prepared market flow charts and unit pricing information based on current market conditions. Figures 18, 19 and 20 outline the potential markets each fuel may enter. For the purpose of these flow charts, EcoEngineers assessed the RFS, LCFS, CFP, BC-LCFS, and the non-transportation and voluntary markets.

In addition, for purposes of this analysis, further assumptions were made regarding the transportation fuel displaced by these renewable products under the CA LCFS, BC LCFS and OR CFP programs. The number of potential credits generated by each renewable product under these programs will be dependent on the compliance curve of the transportation fuel being displaced. These assumptions included the 2022 compliance curve for each of the respective fossil fuels listed below:

- RNG displaces brown gas as transportation fuel; and
- Renewable electricity displaces gasoline as transportation fuel

EcoEngineers previously calculated a preliminary CI score for renewable electricity production at the Gresham facility. The CI Analysis Report can be found at the end of the 2020 study. The calculated CI was $-78 \text{ CO}_2\text{e/MJ}$; however, the report stated the final CI score may vary between 25 and $-100 \text{ CO}_2\text{e/MJ}$. For the purposes of this analysis, renewable electricity in the LCFS/CFP programs will be based on the CI score range of 25 to $-100 \text{ CO}_2\text{e/MJ}$. The 2022 CI compliance curve values were used for the displacement of gasoline, which are $89.50 \text{ gCO}_2\text{e/MJ}$ for LCFS and $93.15 \text{ gCO}_2\text{e/MJ}$ for CFP.

A preliminary CI score has not been calculated for the production of RNG at the Gresham facility. For purposes of unit pricing, CI compliance curve values for the displacement of fossil natural gas were used, which are $79.21 \text{ gCO}_2\text{e/MJ}$ for LCFS and $79.98 \text{ gCO}_2\text{e/MJ}$ for CFP. A project CI score between 30 and $-50 \text{ gCO}_2\text{e/MJ}$ was assumed.

The CI score ranges used in this analysis are representative ranges based on previously approved project pathways similar to Gresham. These ranges are used for high-level unit pricing estimates and account for potential changes in the final CI score. The finalized CI score will still need to be determined.

According to the 2020 feasibility study, the expansion of the anaerobic digestion facility and addition of CHP generators will increase the total power output capacity to 13,896,953 kWh/year. The CI Analysis report performed by EcoEngineers indicates that 5,854,627 kWh/year are needed each year to continue supplying power to onsite operations, leaving an excess of 8,042,326 kWh/year available to sell to renewable energy markets. This excess power equates to 365,560 RINs/year, between 8,000 and 11,700 LCFS credits/year, and between 8,500 and 12,200 CFP credits/year. If the facility upgrades biogas to pipeline quality RNG, it will have the capacity to produce an excess of 280 scfm of biogas, which would generate approximately 87,700 MMBtu/year available to sell. This equates to 1,020,249 RINs/year, between 5,000 and 11,700 LCFS credits/year, and between 4,100 and 10,800 CFP credits/year.

Table 11 shows the potential revenue projections for participation in various renewable energy markets. The revenue opportunity ranges for the LCFS, CFP, and BC-LCFS are based on CI score ranges of 25 to $-100 \text{ CO}_2\text{e/MJ}$ for electricity, and 30 to $-50 \text{ CO}_2\text{e/MJ}$ for RNG. These are representative scores based on projects similar to Gresham's. The range shown in the RNG voluntary market column is due to the potential price ranges for placement of RNG within the non-transportation and voluntary markets.

Figure 18: Renewable Electricity Flowchart

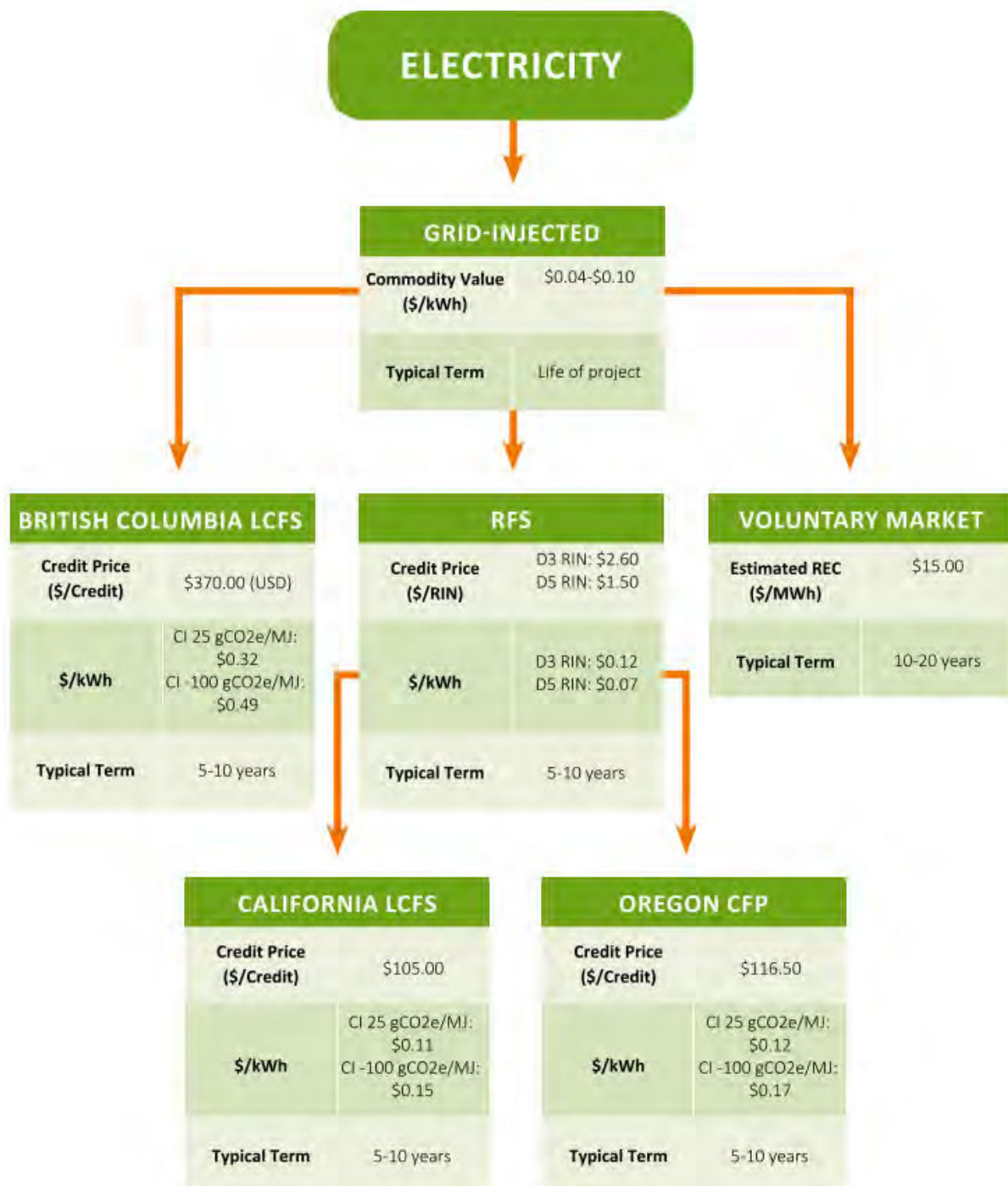


Figure 19: Renewable Natural Gas Flowchart

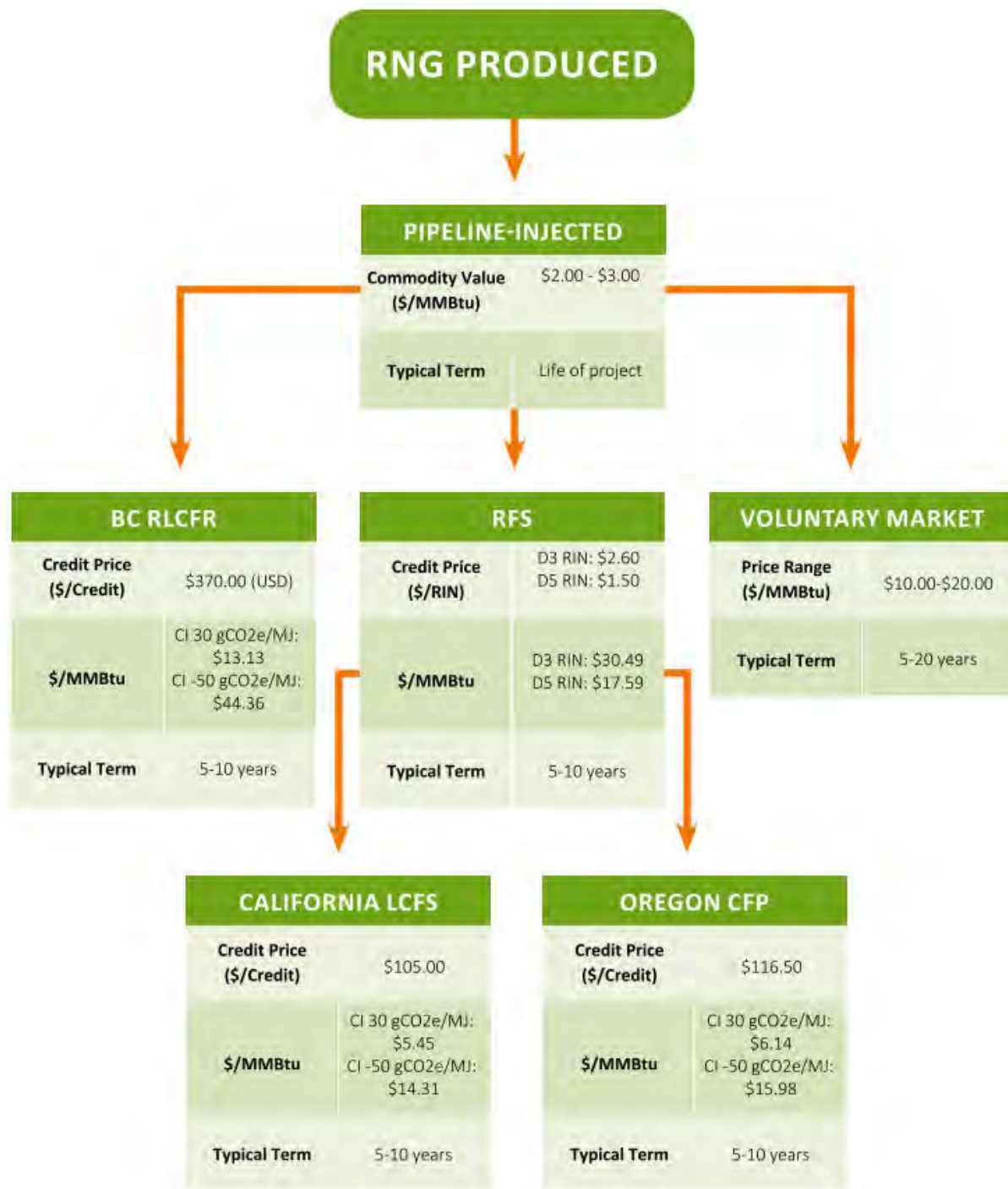


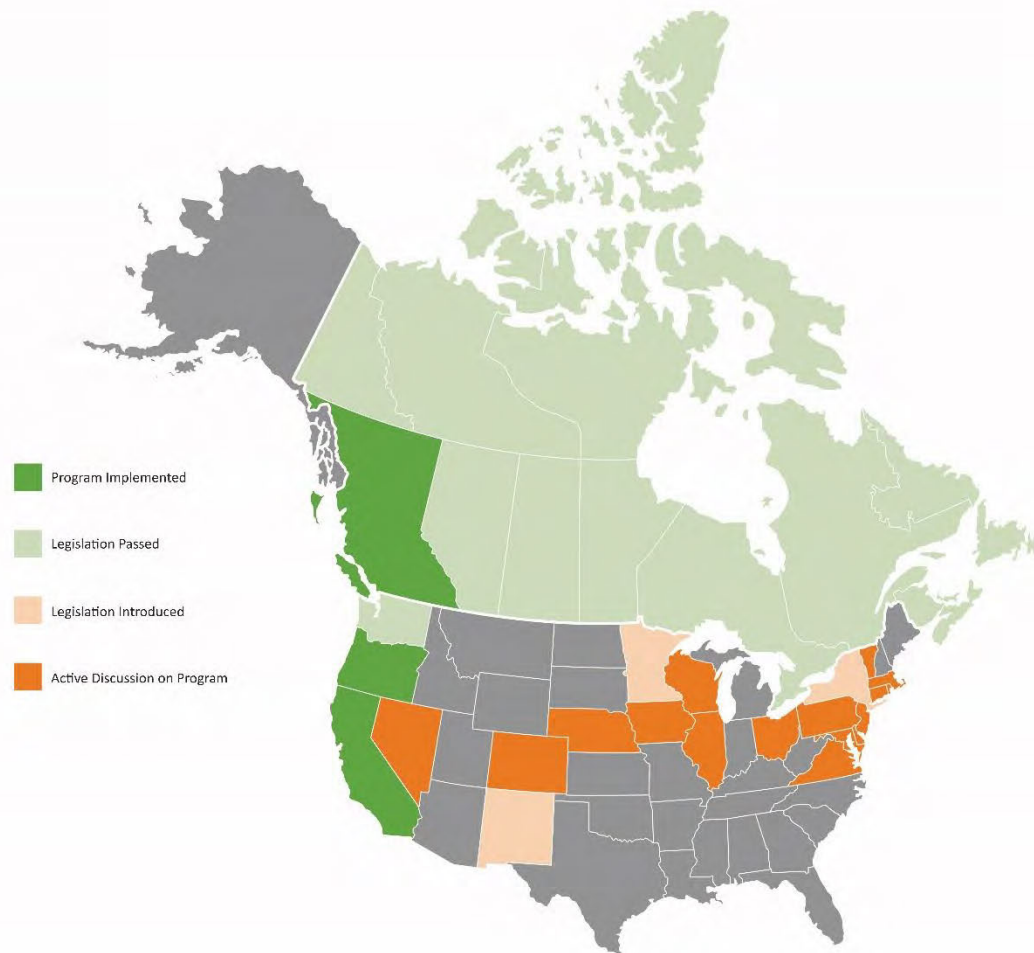
Table 11: Revenue Estimates

	Electricity	RNG
RFS, D3	\$950,457	\$2,673,991
RFS, D5	\$548,340	\$1,542,687
LCFS	\$849,072 - \$1,229,072	\$478,074 - \$1,255,271
CFP	\$983,924 - \$1,405,543	\$538,734 - \$1,401,053
BC LCFS	\$2,580,398 - \$3,919,445	\$1,151,621 - \$3,890,317
Non-Transportation/ Voluntary Market	\$120,635	\$877,000 - \$1,754,000

7.0 Emerging Markets

Many states are considering legislation to promote GHG reduction or meet sustainability goals. Due to the success of the LCFS program in California, many states are considering adopting a similar program with a focus on the transportation sector. The figure below shows a map that highlights the states and countries considering the adoption of an LCFS program. Other states are considering a regulation requiring utilities to purchase a certain percentage of renewable natural gas based on the volume of natural gas distributed within the state. This would not require RNG to be used as transportation fuel and would allow any end use. Section 7.1 provides further insight into the progress that each state has made in adopting new legislation. Additionally, many states have a Renewable Portfolio Standard (RPS) which mandate the increase in electricity production from renewable sources. Some of these programs allow the production of electricity from biogas to count under the RPS. Biogas can also be used to produce hydrogen or be used as process heat in the production of other renewable fuels to lower the carbon intensity of the fuel. Figure 21 illustrates the established and emerging LCFS Markets in North America.

Figure 21: Established and Emerging LCFS Markets in North America



7.1 Potential State Programs

7.1.1 Washington

Washington first attempted to pass a statewide LCFS in 2019 and again in 2020. The legislation aims for a 20% reduction in the carbon intensity of fuels used in the state by 2038 based on 2017 data. As of April 25, 2021, Washington legislation passed the bill. The bill was signed into law by the Governor on May 17, 2021. The program is expected to begin in January 2023.

7.1.2 New York

Under Senate Bill S4003A, New York proposed the establishment of a low carbon fuel standard that aims to reduce the carbon intensity of on-road transportation by 20% by 2030. The bill was proposed in February of 2019 and is currently under review in the Senate Environmental Conservation Committee.

7.1.3 Colorado

Colorado has developed a GHG reduction roadmap which aims for a 50% reduction in GHG emissions by 2030 based on 2005 levels. In 2019, as part of this roadmap process, Colorado has launched a feasibility study on implementing a Clean Fuels Standard. The Colorado Energy Office concluded that state would have to rely on traditional biofuels to meet its reduction goals but has not done a comprehensive analysis

on the tradeoffs involved. Colorado put forward its roadmap in September of 2020 with the exclusion of a CFS but is open to public comment.

7.1.4 Midwest LCFS

A coalition led by the Great Plains Institute and comprising of two dozen ethanol companies, agriculture associations, utilities, and conservation groups have been promoting Midwestern states to adopt an LCFS program. The coalition released a white paper outlining the concept of the LCFS. Currently, the main states that are considering the legislation are Minnesota, Iowa, and South Dakota but would like other Midwestern states to consider the legislation.

8.0 CI Optimization

8.1 Carbon Sequestration

The current version of the CA LCFS regulation, implemented in 2020, incorporated a carbon capture and sequestration (CCS) Protocol. Per this CCS Protocol, “alternative fuel producers, refineries, and oil and gas producers that capture CO₂ on-site and geologically sequester CO₂ either on-site or off-site” are eligible to apply for CCS credits. If approved, an alternative fuel producer, including producers of ethanol, biogas, renewable diesel, renewable gasoline, alternative jet fuel, or low-CI electricity, may generate CCS credits that would then be used to adjust the CI score associated with their CA LCFS fuel pathway.

8.2 Biogas as Process Heat and Power

A major way to optimize the CI is by utilizing the renewable energy, either biogas or electricity, produced onsite, to power Gresham’s facility. Gresham currently uses the biogas generated onsite to supply heat and electricity to facility operations and buildings. If Gresham continues to use these types of renewable energy as process energy within its own facility, the CI score of the facility would benefit. In this scenario, Gresham would continue utilizing a portion of its renewable energy within the fence line, instead of selling all into the low carbon fuel markets to maximize revenue from credits. However, since the low carbon fuel markets are dependent on the CI score for placement, the use of its renewable process energy may help achieve a desirable CI for the portion of its renewable energy that would be marketable.

It is important to note that the CA LCFS does not allow for book-and-claim accounting for process energy. In other words, to benefit from a lower CI through the use of process energy, the producer must “directly” supply the process energy to its fuel production facility. It is therefore beneficial that Gresham will have the ability to produce some of its own process energy, biogas and/or electricity, within the same facility producing the final renewable product (renewable electricity or renewable natural gas).

8.3 Landfill Diverted Feedstock

Since Gresham is planning to produce gas from fats, oils, and greases, as well as other organic wastes, another CI optimization strategy is optimizing the feedstock mix to prioritize landfill-diverted organics.

According to the United States Environmental Protection Agency (USEPA), municipal solid waste (MSW) landfills are the third-largest source of human-related methane emissions in the United States. Landfills account for approximately 15% of methane emissions in the United States. MSW deposited in landfills undergoes anaerobic digestion, producing methane. The methane is then collected by landfill gas (LFG) collection systems. The USEPA has established that the LFG collection systems only capture approximately 75% of the methane produced, and the other 25% is emitted directly into the atmosphere. Anaerobic digesters, for comparison, can capture approximately 98% of the methane produced.

Based on the information from the USEPA, CARB has established a credit for the for the diversion of waste from landfills. By diverting waste from a landfill to a digester, the methane can be captured and used, thus reducing greenhouse gas emissions. By prioritizing landfill diverted feedstocks, Gresham will be able to reduce the CI score of the facility.

One exception to this rule is if there is a law mandating the diversion of organics away from landfills. Under the LCFS program, the facility is still eligible to participate in the CA-LCFS program, but that feedstock may no longer be eligible for landfill diversion credits to reduce the CI score. EcoEngineers could find no such rule or exception pertaining to the OR-CFP.

9.0 Conclusions & Next Steps

High demand exists for renewable fuels throughout the US either from federal and state regulations or voluntary sustainability goals. With multiple market options and each market having separate pros, cons, and risks, Gresham must decide which markets meet its objectives and goals. If longer term revenue stability is more important than price, entering into a non-transportation or voluntary market deal may be the best option. If maximizing revenue is the goal, the RIN and LCFS markets are good options but have increased volatility and regulatory risk. Gresham could also take a portfolio approach by sending a portion of its renewable energy to the transportation markets and a portion to non-transportation and voluntary markets. The BC-LCFS can be less attractive for producers due to the lower potential revenue from participation in only one carbon program.

Throughout the US there is current demand for RNG and renewable electricity either from federal and state regulations or voluntary sustainability goals. In North America, Gresham has the ability to use the concept of book-and-claim to place RNG from its projects into any market in North America. Gresham can also use book-and-claim accounting to place renewable electricity. For the CA LCFS market, the renewable electricity must be supplied to the grid within the California Balancing Authority or, if electricity is generated from an out-of-state resource, the electricity must be supplied to the California grid. The concept of book-and-claim is where a specific amount of renewable energy is injected into the pipeline and the same amount is used elsewhere along the interconnected distribution grid claiming the renewable attributes from the supplied renewable energy.

In addition to the established markets, several states are considering adopting an LCFS program or an RFS program. These new states can add flexibility for Gresham by opening further options for Gresham to sell its renewable energy. However, if these new markets open, it may take several years before credit prices rise to the current values of the OR CFP or CA LCFS markets.

Table 12 shows an evaluation of the major factors affecting participation in renewable electricity and RNG markets.

Table 12: Priority Evaluation of Renewable Electricity vs RNG

Evaluation Criteria	Weight (%)	Maximum Possible Score	Renewable Electricity	RNG
Capital Cost	15	10		
Revenue Potential	30	10		
Market Accessibility	20	10		
Payback Period	30	10		
Oregon Based Program	5	10		
Score	1	10		

Based on this assessment, below are a list of EcoEngineers' recommendations:

- Gresham needs to confirm the CI calculation for the project. The CI score will help determine which market may be the most beneficial for this project. The CA LCFS, OR CFP, and BC-LCFS markets all rely on the CI of the renewable fuel to calculate estimated revenue. EcoEngineers expects that Gresham may likely need a CI score of 0 gCO₂e/MJ or lower to enter these low carbon fuel markets. A slightly positive CI score could be enough to enter these markets; however, in this scenario, Gresham may expect a higher offtake fee.
- The RFS program currently has an existing approved pathway available for renewable electricity. Over 30 registrations have been submitted to the USEPA by multiple projects producing renewable electricity. The USEPA has not yet processed and approved these registrations, allowing producers to generate eRINs. EcoEngineers recommends Gresham follows any progress in this sector of the RFS program.
- Gresham is currently undergoing discussion with NWN for the supply of RNG and PGE for the supply of renewable electricity. EcoEngineers recommends that Gresham continues to consider the non-transportation and voluntary markets for either one of its renewable products as these may provide fixed fee contracts with long term structures, outside of the regulated transportation sector.
- In addition to the established markets, several states are considering adopting an LCFS program. These new states can add flexibility for Gresham by opening further options for Gresham to sell renewable electricity, RNG and, potentially, renewable hydrogen. EcoEngineers recommends Gresham follows any progress of these emerging low carbon fuel programs. However, if these new markets open, it may take several years before credit prices rise to the current values of the OR CFP or CA LCFS markets.

Task 2.6 - Power Utility Coordination and Preliminary Economic Model Update

Date:	February 8, 2023	Jacobs
Project name:	Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project	2020 SW 4th Avenue 3rd Floor Portland, OR 97201 United States T +1.503.235.5000
Attention:	Rob Chapler	
Client:	City of Gresham	
Prepared by:	Corey Klibert and Yash Chaudhary	
Reviewed by:	Matt Noesen and Kristen Jackson	

Outline

1. Introduction
 2. Energy Use Options
 3. Business Case Evaluation
 4. Summary and Conclusions
 5. References
- Appendix A. Process Mass Balance
 Appendix B. Revenue Analysis
 Appendix C. Capital Cost and Annual Operating Costs
 Appendix D. Renewable Energy Market Assessment

Acronyms and Abbreviations

°F	degrees Fahrenheit
AACE	Association for the Advancement of Cost Engineering
BCE	Business Case Evaluation
BOD	biochemical oxygen demand
Btu	British thermal units
CFP	Oregon Clean Fuels Program
CHP	combined heat and power cogeneration
CI	carbon intensity
CNG	compressed natural gas
DEQ	Oregon Department of Environmental Quality
EER	energy efficiency ratio
EPA	U.S. Environmental Protection Agency
eRIN	Electric Renewable Identification Number
EV	electric vehicle
FOG	fat, oil, and grease
FS	food slurry
GHG	Greenhouse gas

gpy	gallons per year
HSOW	high strength organic waste
IRA	Inflation Reduction Act
kW	kilowatt
kWe	kilowatts electricity
kWh	kilowatts per hour
LCFS	California Low Carbon Fuel Standard
MW	megawatt
NPDES	National Pollutant Discharge Elimination System
NWN	Northwest Natural Gas
O&M	operations and maintenance
ODE	Oregon Department of Energy
PPA	power purchase agreement
ppm	parts per million
PS	primary sludge
RE	renewable electricity
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RNG	renewable natural gas
scfm	standard cubic feet per minute
TSS	total suspended solids
VS	volatile solids
WAS	waste activated sludge
WWTP	wastewater treatment plant

1. Introduction

The City of Gresham, OR (City) Wastewater Treatment Plant (WWTP) is divided into two influent treatment trains: the Upper Plant and the Lower Plant. Both trains treat influent wastewater using a combination of screening, grit removal, primary clarification, biological treatment with activated sludge, and chlorination/de-chlorination (which is one system disinfecting the combined upper and lower plant flows). Solids generated in the primary and secondary processes are treated using gravity belt thickeners (currently being replaced with rotary drum thickeners), anaerobic digestion, and dewatering belt filter presses before being hauled offsite for land application. Treated effluent from each train is combined before discharge in the Columbia River through an outfall permitted under the National Pollutant Discharge Elimination System (NPDES).

The WWTP has two mesophilic digesters (95 to 105 degrees Fahrenheit [°F]) that are operated in series. Wastewater solids and fats, oils, and greases (FOG) are sent to the digesters, where solids are broken down by microorganisms to produce biogas and Class B stabilized residuals. Currently, the biogas is converted into electricity and heat using two 400 kilowatts (kW) combined heat and power (CHP) cogeneration engines. The energy generated from the biogas is used for onsite power and heating needs, contributing to the net zero electricity usage at the WWTP. Any excess electricity is fed into the Portland General

Electric (PGE) electrical grid and is regulated by a net metering agreement. However, the City is not paid for the electricity fed into the grid at this time. Electricity is also purchased through a power purchase agreement (PPA) from a third party that operates a solar photovoltaic array located at the WWTP.

The City completed the Feasibility Study of Expanding Liquid Organic Digestion Capacity, CIP 322100 (Jacobs, 2020) to determine if they should accept additional FOG and food slurry that will be diverted from landfills by the Metro Commercial Food Scraps Policy. The existing digesters are at capacity and could not accept any more additional organic waste loading. However, with the expansion of the digestion capacity included in the study, the WWTP could process an additional 30,000 pounds volatile solids per day (lb VS/day) of additional liquid organic waste loading. The additional pounds per day of volatile solids would also produce more biogas, which could be used to generate revenue through either renewable electricity (RE) or renewable natural gas (RNG). This approach would aid the City in going beyond net zero for energy consumption. The business case evaluation (BCE) carried out in the study showed a promising payback period for RE options, especially if grant funding is available to offset upfront capital investment. The next steps included a more detailed predesign of the recommended project.

The renewable energy landscape continues to evolve since completion of the Feasibility Study (Jacobs, 2020). Changes have included:

- The Oregon legislature passed Senate Bill 98, which established RNG targets and rules around RNG procurement for all gas utilities in Oregon. Senate Bill 98 sets the policy framework for gas utilities to buy RNG and deliver it to their customers for residential, commercial, and industrial needs, such as space and process heating. There are not requirements to put the RNG into compressed natural gas (CNG) vehicles. This bill is completely separate from the Oregon Clean Fuels Program and the federal Renewable Fuel Standard (RINs).
- Senate Bill 98 allows natural gas utilities to both procure RNG under long-term contracts and invest in RNG production. Gas utilities can invest in the equipment to process, clean, condition, compress, and interconnect RNG to the local gas distribution network. These investments can be rate-based and can be made both in Oregon and outside of Oregon.
- The Climate Protection Program, which is the outcome of the governor's Executive Order on Climate will also dramatically increase the incentive for gas utilities throughout Oregon to procure RNG.

These policies have led Northwest Natural Gas Company (NWN) to be more involved in RNG development and procurement in recent years. NWN has been executing contracts to purchase RNG under long-term fixed-price contracts and is investing in RNG production and has several projects where they are providing the capital to pay for the RNG cleaning, conditioning, and compression equipment, as well as the pipeline interconnection.

In recent years, the volume of high-value RNG entering renewable energy markets has steadily increased. Since the original BCE was developed in 2020, it has been updated to include RNG in addition to RE. A hybrid option was also considered that consists of increasing the plant's CHP system capacity to produce renewable electricity and cleaning the excess biogas to pipeline quality to sell for revenue. The results from the BCE will help confirm the preferred alternative.

The three options considered in the updated BCE can be summarized as follows:

- Option 1: Renewable Electricity
 - All biogas used to generate RE with expanded CHP system with 2.2 megawatt (MW) capacity
- Option 2: Renewable Natural Gas
 - All biogas cleaned to pipeline quality for injection
- Option 3: Hybrid
 - Base-load CHP system (expanded to 1.2 MW capacity) and clean excess biogas to pipeline quality for injection

2. Energy Use Options

2.1 Overview

This section includes an overview of the potential uses for the digester gas produced from the anaerobic digestion process. The gas produced could be used in two distinct ways: combust the gas with cogeneration engines to produce heat and electricity or upgrading the gas to pipeline quality. The energy created in both scenarios could be beneficially used on-site or utilized off-site.

In both scenarios, energy may be sold to third parties, via long-term contracts with power companies, or into the renewable energy credit market. Jacobs consulted both PGE and NWN to explore the options. Selling to third parties was not as lucrative due to high transmission and interconnection fees and the inability to identify a third party to consume the amount of energy the Gresham WWTP would realistically produce since it is considered a small amount. Ultimately, entering into the renewable credit generation market appears to have the most promising revenue generation. Within the renewable market, three tiers of revenue are generated. Figure 2-1 illustrates the structure of revenue generation and typical values for RE (blue) and RNG (green) options.

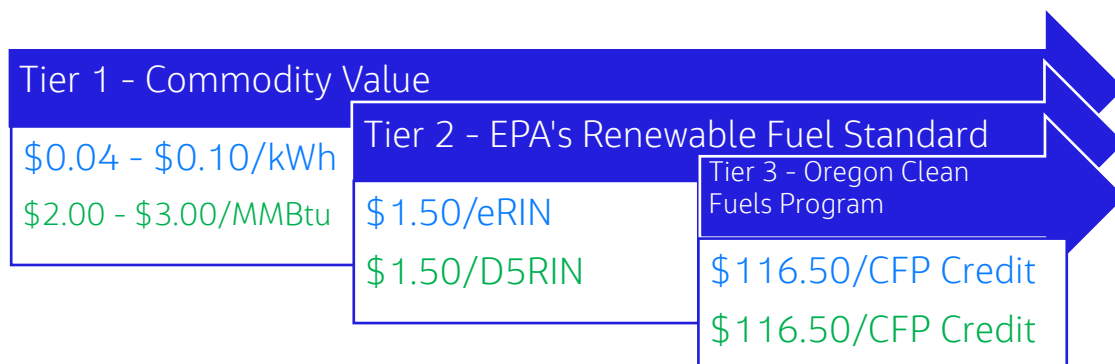


Figure 2-1. Tiered Structure of Renewable Energy Credit Market

2.1.1 Commodity Value (Tier 1)

Tier 1 generates revenues at commodity values, sold to a power company by the City. Revenue generated in this tier is based purely on the amount of power sold (i.e., electricity in kilowatt-hours [kWh] or natural gas in metric millions of British thermal units [MMBtus]).

2.1.2 Renewable Fuel Standard (Tier 2)

The second tier is revenue generated at the Federal level by selling credits into the Federal Renewable Fuel Standard (RFS). Credits associated with this program are quantified by Renewable Identification Number (RIN); this is the "currency" of the RFS program and can be sold at market value to obligated parties (refiners and importers of gasoline and diesel), renewable fuel exporters, renewable fuel producers, and registered RIN market participants (domestic and foreign companies).

With respect to renewable electricity, there have historically been no active pathways for electric RIN (eRIN) generation. However, on December 1, 2022, the U.S. Environmental Protection Agency (EPA) announced a proposed rule to establish required RFS volumes and percentage standards for 2023, 2024,

and 2025, as well as to propose a series of important modifications to strengthen and expand the RFS program. The Proposed Renewable Fuel Standards for 2023, 2024, and 2025 (Proposed RFS) would provide active eRIN pathways beginning January 2024. The Proposed RFS also increases the equivalence value of eRINs by almost 300 percent (the current equivalence value of 22.6 kWh/eRIN would be replaced by a value of 6.5 kWh/eRIN).

RINs generated by biogas production (now potentially to include eRINs) are classified by a D-Code. D-Codes are determined by the type of fuel (biodiesel, ethanol, natural gas), type of feedstock, processes used to create the fuel, and the calculated reduction of greenhouse gas (GHG). Biogas produced from the anaerobic digestion of wastewater solids and food waste generates D3 RINs, while biogas produced from the digestion of FOG and food waste generates D5 RINs. The market value of D3 RINs is greater than that of D5 RINs. Historically, when FOG has been co-digested with wastewater solids, EPA has determined that all of the biogas produced in the process should generate only D5 RINs, resulting in a negative incentive to co-digest FOG with other feedstocks such as wastewater solids, which earn the more lucrative D3 RINs when not co-digested with FOG or rescued food waste. The Proposed RFS includes a modification to this determination that would eliminate this constraint if enacted. Under the new rule, a facility producing biogas from co-digested wastewater solids, food waste, and FOG would generate D3 RINs for the fraction of biogas produced from wastewater solids digestion and D5 RINs only for the fraction produced from FOG and food waste digestion.

The proposed establishment of eRINs will provide a significant boost in revenue generation for the RE scenarios, and the proposed differentiation in D-Codes for biogas produced from co-digestion would increase revenue generation for both RE and RNG.

2.1.3 Oregon Clean Fuels Program (Tier 3)

The third tier is revenue generated at the State level, for example, by selling credits into the Oregon Clean Fuels Program. Credits associated with this program are known as OR CFP credits and are the “currency” of the OR CFP. These credits are generated by the producer and sold into the CFP program at market value. Each tier revenue contributes to the total revenue the Gresham WWTP could generate within the renewable energy credit market.

2.2 Assumptions

While the credit prices are the same within the two credit programs (RFS and OR CFP) for both RE and RNG, the amount of credits generated (whether eRINs, RINs, or CFP Credits) is variable. To sell credits within either of these programs, a carbon intensity (CI) score specific to the facility’s fuel production process is calculated. This score impacts how many credits are generated based on the volume of power produced. Lower CI scores indicate less environmental impact, and therefore result in higher credit generation rates. Higher CI scores indicate greater environmental impact, resulting in lower credit generation rates.

Preliminary ranges of CI scores were assumed for both RE and RNG production at the Gresham facility. The two scores are different based on the reference fuel, or fuel the new energy is replacing. For RE production, a CI score of 25 grams of carbon dioxide equivalent per megajoule of energy (gCO₂e/MJ) was assumed as a worst case, and -100 gCO₂e/MJ assumed as a best case. These numbers were based on a preliminary CI calculation performed by EcoEngineers for the City of -78 gCO₂e/MJ.

While site specific CI scores for RNG have not yet been calculated for this project, Jacobs in consultation with EcoEngineers has assumed a range of CI scores for this project based on knowledge of other similar type projects. The assumed CI score range for RNG production is 30 gCO₂e/MJ (worst case) to -50 gCO₂e/MJ (best case). These CI score ranges for each type of energy production provide a conservative assumption to account for possible ranges of credit generation. Once these credits have been generated and sold, a percentage of the credit revenue must be shared with the offtaker. This offtake percentage will vary primarily based on market climate and CI score.

Jacobs has been working closely with EcoEngineers, a specialty consultant in the renewable energy credit markets, to calculate the highest potential revenue estimates for likely RE and RNG scenarios. EcoEngineers has advised the listed credit sale process, offtake percentages, CI score, eRIN equivalency values, and range of generated credits (Appendix D).

2.3 Methodology and Assumed Values

Utilizing the assumed and advised values listed in the EcoEngineers report (Appendix D), revenue estimates were made utilizing the methodology outlined in Figure 2-2.



Figure 2-2. Methodology for Revenue Estimate Generation

2.3.1 Determine Amount of Energy to Be Sold

Biogas produced from food slurry, FOG, and biosolids at the Gresham WWTP is eligible to produce credits in both the RFS and OR CFP. A solids mass balance across the plant was developed to estimate the quantity of biogas that could be generated through the year 2047 if additional FOG and food slurry were accepted by the facility. General assumptions of the process mass balance included the following:

- Upper Plant aeration basin nitrification
- Addition of one new 1-million gallon thermophilic digester
- Existing digesters converted to operate at thermophilic temperatures

Table 2-1 presents the assumptions for the volumes of FOG and food slurry that would be accepted on a daily average basis. Current FOG loading is based on plant data with historical peaking factors applied. Peaking factors were not applied to additional FOG and food slurry loading rates due to uncertainty of future availability and ramp up of food rescue programs.

Table 2-1. Assumptions for Daily Average FOG/Food Slurry Loading to Gresham WWTP

Parameter	Current FOG	Additional FOG	Food Slurry
Flow (gpd)	11,594 (Average) 13,882 (Max Month) 14,660 (Max 14-day)	14,356	18,396
Total Solids (lb/d)	9,066 (Average) 11,762 (Max Month) 11,974 (Max 14-day)	11,225	23,014
Volatile Solids (lb/d)	8,676 (Average) 11,256 (Max Month) 11,459 (Max 14-day)	10,743	20,022

lb/d = pounds per day; gpd = gallons per day.

The average of the dry season and wet season Influent load projections from the 2017 Master Plan (CH2M) were used as the basis for the solids mass balance. These projections extended through 2036 and

were extrapolated to 2047 by applying growth rates from the Master Plan – an annual growth rate of 1 percent for 5-day biochemical oxygen demand (BOD₅) loading and 0.6 percent for total suspended solids (TSS).

Table 2-2 presents the updated influent BOD₅ load projections, and Table 2-3 presents influent TSS load projections.

Table 2-2. Influent BOD₅ Load Projections (pounds of total solids per day)

Period	Year				
	2027	2032	2037	2042	2047
Annual Average	22,035	22,470	23,194	23,919	24,788
Maximum Month	24,223	24,701	25,500	26,298	27,256
Maximum 14-day	26,645	27,171	28,049	28,928	29,982

Table 2-3. Influent TSS Load Projections (pounds of total solids per day)

Period	Year				
	2027	2032	2037	2042	2047
Annual Average	21,155	21,577	22,282	22,986	23,832
Maximum Month	23,287	23,752	24,529	25,305	26,236
Maximum 14-day	25,615	26,127	26,981	27,836	28,860

A previously calibrated whole-plant process model, developed in Jacobs' proprietary Pro2D modeling package, was used to estimate the solids mass balance through the plant. The projected mass of wastewater solids from primary (PS) and waste activated solids (WAS) was estimated using the influent load projections above. These were compared with data of current wastewater solids loads and found to agree within a margin of less than 5 percent. Table 2-4 presents the projections of wastewater solids developed with this approach.

Table 2-4. Wastewater Solids Loading Projections (pounds of total solids per day)

Period	Year				
	2027	2032	2037	2042	2047
Annual Average	34,071	35,965	37,860	39,754	41,649
Maximum Month	41,046	43,329	45,611	47,893	50,176
Maximum 14-day	41,755	44,076	46,398	48,720	51,042

There are known issues with the accuracy of biogas production estimates from currently available process model packages, therefore, biogas production rates were estimated using assumptions of digester performance and operating parameters supported by current data where possible and informed by Jacobs' industry experience where no current data existed. These assumptions are summarized in Table 2-5, and detailed calculations and all assumptions can be found in Appendix A – Process Mass Balance.

Table 2-5. Summary of Key Assumptions for Digestion and Biogas Production

Parameter	Units	Value	Comments
VS/TS, WW solids to digestion	%	82%	Based on historical data
DFS total solids	%	5.5%	Based on historical data
VSR, WW solids to digestion	%	64%	Based on expected VSR from thermophilic digestion
VSR, FOG	%	95%	Based on Jacobs' experience with operating digesters
VSR, Food Slurry	%	85%	Based on data from East Bay Municipal Utility District
Specific digester gas production, WW solids	scf/lb VS destroyed	15	From WEF MOP 8 and Jacobs' experience
Specific digester gas production, FOG	scf/lb VS destroyed	15	From WEF MOP 8 and Jacobs' experience
Methane yield, Food Slurry	scf CH ₄ /lb TS digested	6	WERF Report on High-Strength Waste Co-digestion

Digester Feed Solids = DFS; MOP = Manual of Practice; scf/lb = standard cubic feet per pound; VS = volatile solids; VS/TS = volatile solids per total solids; VSR = volatile solids reduction; TS = total solids; WEF = Water Environment Federation; WERF = Water Environment Research Foundation; WW = wastewater.

Table 2-6 presents the biogas production rates that were estimated from the digester feed loads and the assumptions above.

Table 2-6. Biogas Production Projections (standard cubic feet per minute)

Period	Year				
	2027	2032	2037	2042	2047
Annual Average	526	536	547	557	567
Maximum Month	590	602	615	627	640
Maximum 14-day	595	608	621	634	646

Table 2-7 presents the assumptions used to calculate the amount of renewable electricity that could be produced from the available biogas from the projections in Table 2-6.

Table 2-7. Summary of Key Assumptions for Conversion of Biogas to RE

Parameter	Value	Units	Comments
Methane content of biogas, WW solids	60	%	Within typical range for digesters with only municipal feed sludge
Methane content of biogas, FOG	65	%	Within typical range for digested FOG
Methane content of biogas, Food Slurry	65	%	Based on sampling of operating Food Slurry digesters
Net digester methane content	63	%	Calculated value based on methane content and feed rates of feedstocks
Energy content of methane	910	Btu/scf LHV	National Institute of Standards and Technology
Net digester gas energy content	575	Btu/scf LHV	Calculated value based on methane content and biogas production rate assumptions above
Cogeneration electrical efficiency	42	%	From Caterpillar
Kilowatt-to-Btu/hr conversion factor	3,412	kW/Btu/hr	Constant conversion factor
Annual average plant power demand	650	kWe	Based on historical data
Annual average solar power production	50	kWe	Based on historical data
Future power demand (excluding RNG Upgrading System demand)	300	kWe	Assumes additional loads for Upper Plant nitrification and new digestion and biogas systems (excluding RNG Upgrading System)
Engine up-time	90	%	
Kilowatt-to-Btu/hr conversion factor	3,412	kW/Btu/hr	Constant conversion factor

Btu/scf LHV = British thermal units per standard cubic foot of lower heating value; kW/Btu/hr = kilowatts per British thermal unit per hour; kWe = kilowatts in renewable electricity.

Conversion of all available biogas to RE would result in the total available electrical energy from CHP presented in Table 2-8.

Table 2-8. Renewable Electricity Production Projections (kWe)

Period	Year				
	2027	2032	2037	2042	2047
Annual Average	2,208	2,250	2,291	2,332	2,374
Maximum Month	2,471	2,520	2,570	2,620	2,669
Maximum 14-day	2,495	2,545	2,596	2,646	2,697

To simplify the calculation of revenue generation from renewable energy for each of the three options (RE, RNG, and hybrid) for the BCE, the midpoint value of year 2037 was used to determine the average annual energy to be sold. For each option, the average annual amount of energy to be sold was determined by subtracting applicable in-plant uses from the total amount of renewable energy produced as follows:

- Option 1 – RE: Total electrical energy produced minus plant power demand

- Year 2037 annual average: 17,400,000 - 7,900,000 = **9,500,000 kWh/year**
- Option 2 – RNG: Total RNG produced assuming 90 percent uptime of RNG Upgrading System with costs for plant electricity and natural gas subtracted from revenue in BCE
 - Year 2037 annual average: **149,000 MMBtu/year**
- Option 3 – Hybrid: Excess RNG produced after base loading CHP system up to 1.2 megawatts (MW) and using some RNG for boiler heating to satisfy excess plant demand remaining after CHP
 - Year 2037 annual average: **74,000 MMBtu/year**

2.3.2 Credit Generation of Each Program

Estimates of commodity values for RE and RNG were supplemented with information from PGE and NWN. Energy estimates for cost of selling electricity or RNG and quotes for system installation costs were utilized to calculate the revenue estimates.

Currently, the RFS program has no approved pathways for the generation of electricity RINs (eRINs) as discussed previously. The Proposed RFS for eRIN pathways was announced on December 1, 2022; the finalized eRIN rule is anticipated in June 2023; and active eRIN pathways to be opened in September 2023. eRIN generation estimates are based on an equivalency value range advised by EcoEngineers.

Biogas production generates RINs with designated D-Codes. It is assumed that biogas produced at the Gresham facility will qualify for D5 RIN production. Since the RIN program has been established for biogas, EcoEngineers advised an average equivalency value for RIN generation.

Tables 2-9 and 2-10 list assumed equivalency values and resultant RFS eRIN or D5 RIN generation estimates.

Table 2-9. RFS eRIN Generation Values for RE Production

Variable	Scenario	Value	Unit
Available renewable electricity	Baseline	9,500,000	kWh/year
Equivalency value	Best Case	0.09	eRINs/kWh
	Worst Case	0.04	eRINs/kWh
Resultant eRIN generation estimate	Best Case	860,100	eRINs/year
	Worst Case	418,600	eRINs/year

Table 2-10. RFS D5 RIN Generation Values for RNG Production

Variable	Scenario	Value	Unit
Available renewable electricity	Baseline	149,000	MMBtu/year
Equivalency value	Average	0.086	D5 RINs/MMBtu
Resultant D5 RIN generation estimate	Average	1,725,000	D5 RINs/year

Credit revenue generation (credit yields) for the Oregon Clean Fuels Program (OR CFP) depends upon a reference CI score (CI score associated with the fuel the renewable fuel will be replacing), project CI score, energy density (specific to reference fuel), fuel volume and an energy efficiency ratio (EER). Equation I outlines the method for calculating credit yields of the eligible fuel.

$$OR\ CFP\ Credits = \left(Reference\ CI\ Score - \frac{Project\ CI\ Score}{EER} \right) \times Energy\ Density \times 0.000001 \times Fuel\ Volume \times EER$$

Equation 1

Tables 2-11 and 2-12 list assumed values for variables included in this calculation, as advised by EcoEngineers (with the exception of fuel volumes) and resultant CFP credit generation values.

Table 2-11. OR CFP Credit Generation Values for RE Production

Variable	Assumed Value	Units	Basis
Reference CI score	93.15	gCO ₂ e/MJ	Gasoline compliance curve
Energy density	3.6	MJ/kWh	Electricity
Energy efficiency ratio	3.4	--	Light duty and electric vehicle (EV) applications
Project CI score	-100 to 25	gCO ₂ e/MJ	Assumed range
Fuel volume	9,460,800	kWh/year	See previous section calculation
Resultant generated credits	10,001	OR CFP credits	High CI score
	14,356	OR CFP credits	Low CI score

Table 2-12. OR CFP Credit Generation Values for RNG Production

Variable	Assumed Value	Units	Basis
Reference CI score	79.98	gCO ₂ e/MJ	Fossil CNG
Energy density	105.5	MJ/Therm	CNG
EER	1.0	--	Heavy duty applications
Project CI score	-50 to 30	gCO ₂ e/MJ	Assumed range
Fuel volume	148,690	MMBtu/year	See previous section calculation
Resultant generated credits	7,550	OR CFP credits	High CI score
	19,633	OR CFP credits	Low CI score

2.3.3 Revenue of Program Credits

The RFS and OR CFP are both dynamic markets with fluctuating sale prices of credits. Like any market, RFS credit fluctuations may be caused by supply and demand considerations, general market forces, political forces, and implementation decisions of the EPA. Figure 2-3 illustrates the changing rates of different classifications of RINs over recent years.

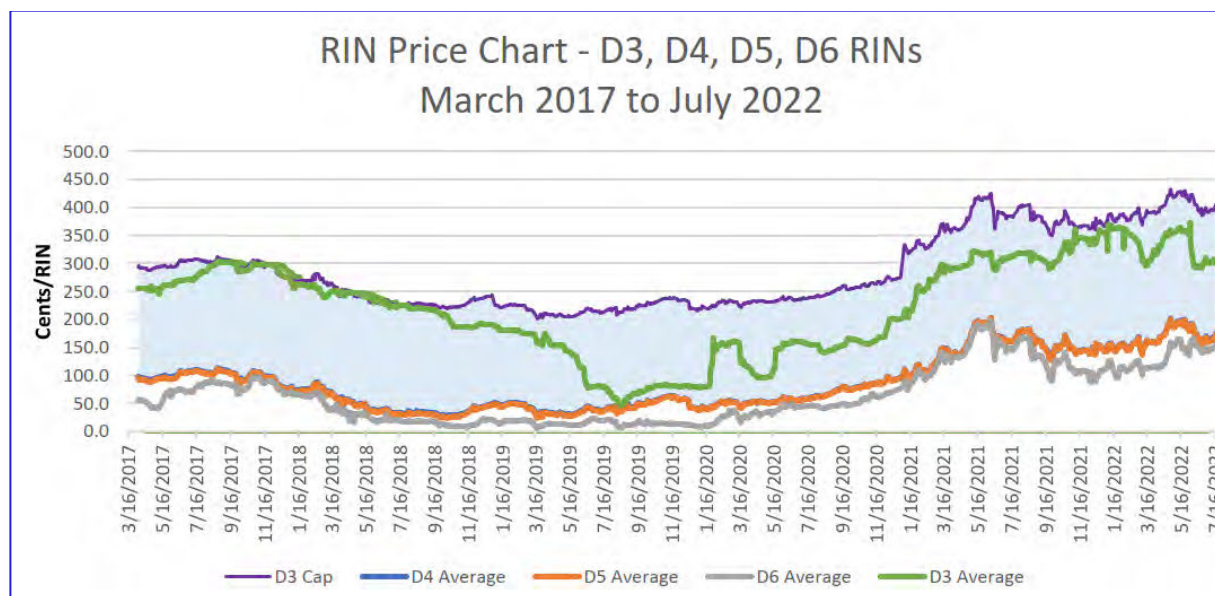


Figure 2-3. Historic RIN Price Fluctuations

Source: EcoEngineers

The OR CFP credit prices are also affected by general market conditions and can be prone to fluctuations due to the program's credit bank framework. In Oregon, credits are generated by credit producers, but deficits can also be incurred. This can occur in cases where program participants are not meeting carbon intensity compliance targets. Historically, credit generation has outpaced deficits. Figure 2-4 illustrates the program's total credit bank and subsequent credit price for recent years.

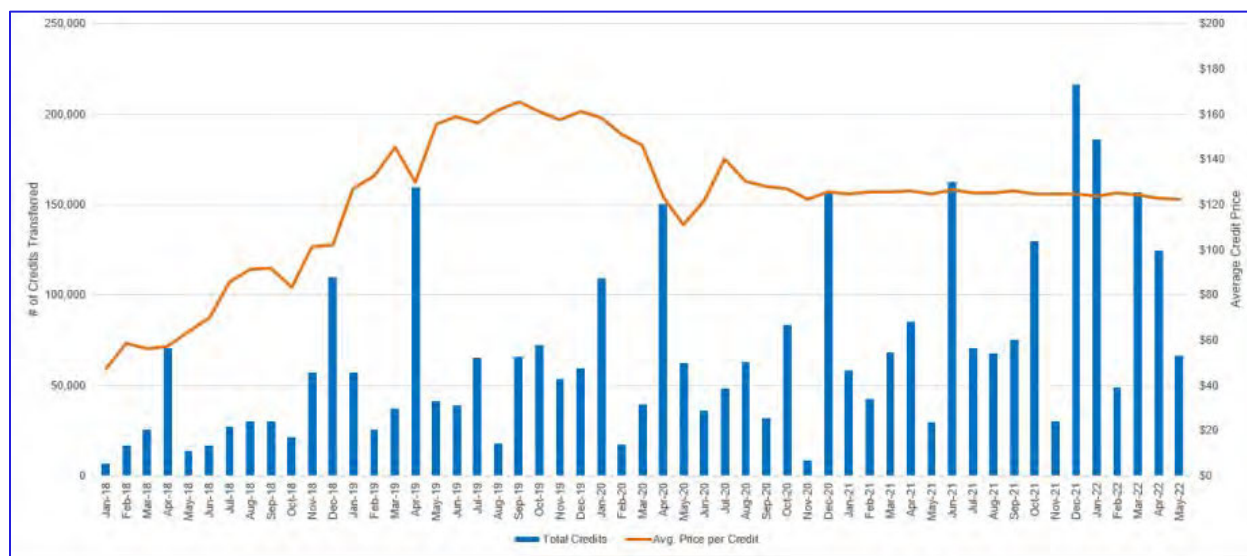


Figure 2-4. Historic OR CFP Credit Price Fluctuations

Source: EcoEngineers

Taking historic fluctuations into consideration, Table 2-13 lists reasonably assumed credit sale prices and Table 2-14 includes the total revenue for each program utilizing the assumed values listed in Tables 2-9 through 2-13.

Table 2-13. EcoEngineers Advised Credit Prices

Program	Program Currency	Sale Price
RFS	D5 RINs	\$1.50 / RIN
OR CFP	OR CFP credits	\$116.50 / CFP credit

Table 2-14. Program Specific Revenue Estimates

Energy	Program	Scenario	Credits Generated	Program Revenue
Renewable electricity	RFS	Best case	860,100 eRINs	\$1,290,100
		Worst case	418,600 eRINs	\$627,900
	OR CFP	Best case (low CI score)	14,400 CFP credits	\$1,665,300
		Worst case (high CI score)	10,000 CFP credits	\$1,160,100
Renewable natural gas	RFS	Average	1,724,800 D5 RINs	\$2,587,200
	OR CFP	Best case (low CI score)	19,600 CFP credits	\$2,287,200
		Worst case (high CI score)	7,600 CFP credits	\$879,600

2.3.4 Program Offtake Fees

The offtaker receives a portion of the revenue and the remaining credit revenue goes to the City. The offtake percentage depends on several parameters. Due to the uncertainties associated with the eRIN market, it is impossible to know exactly what the offtake percentage will be since the pathway is not yet approved. There is a possibility that electric car manufacturers could be the offtaker, which may result in high offtake percentages. If the EPA retains control of the offtake position, it is likely the offtake percentages will mirror the RNG RIN market, which are lower than anticipated car manufacturer percentages.

Like credit generation within the OR CFP program, offtake percentages are also CI score dependent. However, these percentages are less vulnerable to fluctuations. Therefore, three offtake percentages were assumed to reflect a high, average, and low CI score with a tighter range as shown in Table 2-15 for the RE production within the RFS and CFP credit markets.

Table 2-15. Assumed Offtake Percentages for RE Credit Markets

Program	Scenario	Offtake Percentage
RFS	Car manufacturer controlled	40%
	EPA controlled	15%
OR CFP	High CI score	40%
	Average CI score	30%
	Low CI score	20%

Much like RIN generation, offtake percentages within the RFS program for biofuels (i.e., RNG) is more established than eRINs offtake percentages. For these reasons it was reasonable to assume a narrower range of offtake percentages for RNG production within the RFS program. Offtake percentages for RNG production within the OR CFP program follow the same offtake percentages as for RE production within the program.

Table 2-16 lists assumed offtake percentages associated with RNG production within the RFS and CFP credit markets.

Table 2-16. Assumed Offtake Percentages for RNG Credit Markets

Program	Scenario	Offtake Percentage
RFS	High offtake %	20%
	Average offtake %	15%
	Low offtake %	10%
OR CFP	High CI score	40%
	Average CI score	30%
	Low CI score	20%

2.3.5 Net Revenue Estimates

The detailed breakdown of revenues for Options 1 through 3, including all sub-options, equivalency value ranges, and offtake percentages, are presented in Appendix B – Revenue Analysis.

3. Business Case Evaluation

A business case evaluation was completed for the RE, RNG, and a hybrid alternatives. The purpose of the business case model is to provide the breakeven payback period.

The business case included:

- Capital costs
- Operations and maintenance (O&M) costs
- Revenues, including FOG and food slurry tipping fees, selling energy (gas, electricity, etc.) and associated renewable energy incentives (e.g., RINs)
- Critical non-monetary evaluation criteria
- Effect of capital cost offsets (tax credits, grants)
- Sensitivity of revenue generation to incentive values

The infrastructure common across all energy use alternatives includes high strength waste receiving infrastructure upgrades, upgrades to existing anaerobic digesters, a new thermophilic digester, biosolids storage, and gas conditioning treatment upgrades. The RE option includes CHP engines to produce renewable electricity, and the RNG option includes biogas upgrading system to pipeline quality natural gas and injection. The hybrid option includes equipment for CHP and biogas upgrading.

3.1 Economic Evaluation

3.1.1 Summary of Capital Cost Estimates

The capital costs were built including the following components:

- Baseline Option – New mesophilic digester + FOG/gas conditioning upgrades
- RE, RNG, and Hybrid Options – New thermophilic digester and upgrades to existing digesters

A capital and annual cost estimate was generated for each alternative: RE, RNG and Hybrid and the details of the costs are included in Appendix C – Capital Costs and Annual Operating Costs. Capital costs were estimated using similar equipment cost proposals from other projects. Typical cost factors were added to the equipment costs to account for installation, instrumentation and control, and piping and mechanical appurtenances. Building and equipment pad costs were based on preliminary size estimates and an assumed unit cost per square foot. Building costs include building utilities and foundation piles.

Percentages were added to the total cost of the combined costs of equipment, installation, and buildings or equipment pads to account for additional project needs such as sitework, electrical, instrumentation and controls, mechanical, etc. Standard contractor markups, overhead, profit, mobilization, and a market adjustment factor for the Gresham region were included. A 30 percent contingency was added.

Engineering, administration, and legal support were assumed to cost 24 percent of the construction cost subtotal. A Gresham administration fee of 14 percent was added to the project delivery cost subtotal to generate the total capital cost estimate for each alternative.

Annual costs and revenues were estimated using preliminary equipment size estimates and assumed unit costs. Table 3-1 includes the major assumptions included in the economic analysis, for all details see Appendix C.

Table 3-1. Economic Model Assumptions

Parameter	Value / Unit
Cost of electricity purchased from local utility	\$.071/kWh
Labor cost, burdened	\$100,000/year/full time employee
FOG tipping fee	\$.09/gallon
Food slurry tipping fee	\$.06/gallon
Bond rate	4.5 percent
Inflation rate	3.0 percent
Real discount rate	1.5 percent
Capital period	20 years

Table 3-2 shows the status of design development relative to Association for the Advancement of Cost Engineering International (AACE) Publication 18R-97 (AACE, 2011), which is intended to reduce the probability of a project cost overrun or underrun to less than 50 percent. This estimate is considered a Class 5 estimate under AACE recommended practices.

Table 3-2. Cost Estimate Classification Matrix for Process Industries, AACE Publication 18R-97

	Primary Characteristic	Secondary Characteristic		
Estimate Class	Maturity Level of Project Definition Deliverables	End Usage	Methodology	Expected Accuracy Range
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%

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Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%
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H = high; L = low.

Per AACE, the expected accuracy range of the estimate is minus 20 to minus 50 percent on the low end, and plus 30 to plus 100 percent on the high end. The accuracy factors are applied based on professional judgement of the estimator and owner/organizational experience with cost estimating.

The capital cost estimates for the different options are summarized in Table 3-3.

Table 3-3. Project Cost Summary for Options 1, 2, 3

Item	Markup	Baseline Scenario	Option 1: RE	Option 2: RNG	Option 3: Hybrid
FOG/FS receiving facility - new and rehab existing	-	\$700,000	\$1,100,000	\$1,100,000	\$1,100,000
Anaerobic digesters system - convert existing tanks	-	\$4,000,000	\$4,500,000	\$4,500,000	\$4,500,000
Anaerobic digester system - new tank	-	\$6,500,000	\$6,500,000	\$6,500,000	\$6,500,000
Dewatering, cake conveyance, and cake storage	-	\$0	\$700,000	\$700,000	\$700,000
Gas conditioning - new and rehab existing	-	\$1,000,000	\$2,100,000	\$8,200,000	\$8,200,000
CHP	-	\$0	\$5,100,000	\$0	\$2,500,000
Boiler	-	\$0	\$800,000	\$1,300,000	\$800,000
Subtotal		\$12,200,000	\$20,800,000	\$22,300,000	\$24,300,000
Contractor Markups					
Mobilization	5%	\$12,800,000	\$21,800,000	\$23,400,000	\$25,500,000
General conditions	7%	\$13,700,000	\$23,400,000	\$25,100,000	\$27,200,000
Overhead	12%	\$15,400,000	\$26,200,000	\$28,100,000	\$30,500,000
Profit	6%	\$16,300,000	\$27,700,000	\$29,800,000	\$32,300,000
Insurance & bond	3%	\$16,800,000	\$28,600,000	\$30,700,000	\$33,300,000
Contingency					
Design/estimating contingency	30%	\$21,800,000	\$37,200,000	\$39,900,000	\$43,300,000
Market adjustment factor	5%	\$22,900,000	\$39,000,000	\$41,800,000	\$45,500,000
Project Delivery Costs					

Table 3-3. Project Cost Summary for Options 1,2, 3

Item	Markup	Baseline Scenario	Option 1: RE	Option 2: RNG	Option 3: Hybrid
Project and construction management	5%	\$24,100,000	\$41,000,000	\$43,900,000	\$47,800,000
Permitting	1%	\$24,300,000	\$41,400,000	\$44,400,000	\$48,200,000
Engineering	10%	\$26,600,000	\$45,300,000	\$48,500,000	\$52,800,000
Services during construction	5%	\$27,700,000	\$47,200,000	\$50,600,000	\$55,000,000
Commissioning	3%	\$28,400,000	\$48,400,000	\$51,900,000	\$56,400,000
Gresham administration charge	14%	\$32,400,000	\$55,200,000	\$59,200,000	\$64,300,000
NWN interconnection charge*	-	\$32,400,000	\$55,200,000	\$61,700,000	\$66,800,000
Total Cost					
Estimated Total Project Capital Cost	-	\$32,400,000	\$55,200,000	\$61,700,000	\$66,800,000
Estimated Total Project Life Cycle Cost	-	\$65,530,000	\$48,410,000	\$48,040,000	\$57,551,000

Note: Actual total project cost to fall within -50% and 100% of estimated cost.

*NWN interconnection charge only applies to RNG options that do not have fee waived via fixed price agreement with NWN. Does not apply to RE or Baseline Options. The total project cost for RNG options with interconnection charge waived would be \$2.5 million less than the costs shown above.

3.1.2 Summary of Revenue Potential

For the business case evaluation, the capital costs were compared against the revenue potential in order to establish the possible payback scenarios. The potential revenues include the tipping fees from the FOG and food slurry delivery trucks, and revenues generated from selling RE or RNG.

Renewable electricity Option 1 includes three sub-options for maximum revenue generation potential:

- 1a – commodity value of the electricity plus revenues from federal or state incentive programs
- 1b – revenues from Small Generator Interconnection Program from PGE
- 1c – revenues from the voluntary market or a direct sell to an entity

The renewable natural gas Option 2 includes two sub-options for maximum revenue generation potential:

- 2a – commodity value of the RNG plus revenues from federal or state incentive programs
- 2b – revenues from selling RNG to NWN, either pipeline-ready or raw gas

The hybrid approach Option 3 includes two sub-options for maximum revenue generation potential:

- 3a – electrical power generation to meet WWTP demands and revenues from selling excess RNG at commodity value plus incentives

- 3b – electrical power generation to meet WWTP demands and revenues from selling excess RNG to NWN under fixed price contract where NWN procures the RNG Upgrading Skid and waives the interconnection charge

The options that feature sale of renewable electricity or natural gas at commodity value and earning incentives have the most potential revenue generation but also carry the highest risk, stemming from uncertainty in the value, marketability, and longevity of the incentive programs. As a result, the revenue floor of these options could potentially be as low as the market value of the basic commodity (electricity or natural gas). Furthermore, the upper range of revenue from renewable electricity depends on eRINs values, which are still in development, and nominal values of Oregon CFP credits, for which there is currently a developing market. The highest revenue scenarios from this option rely on high values for both eRINs as well as nominal values for CFP credits.

The option to sell RNG to NWN (Option 2) contains two sub-options. One sub-option includes NWN paying for all of the capital cost of the RNG treatment system and interconnection, with the agreement for NWN to purchase RNG at \$5 per MMBtu (roughly market value for conventional natural gas). The second sub-option includes the City paying for all of the capital costs associated with the RNG treatment system and interconnection and selling NWN pipeline quality gas at a price of \$13 per MMBtu.

The hybrid Option 3 has two sub-options. Both include a portion of the biogas used for CHP generation and for running the boilers with excess RNG sold to NWN. One sub-option assumes that the CHP system would generate sufficient heat and electricity to meet plant demands, and the excess pipeline quality RNG would be sold at commodity value plus incentives. The second sub-option would similarly base-load the CHP system to meet plant demands, but would involve a fixed price contract with NWN to buy RNG as well as procure the RNG Upgrading System and waive the interconnection charge.

The ranges of projected revenue from each of the options included in the report are presented in Table 3-4.

Table 3-4. Revenue Potential of Available Options for Tipping Fees and Renewable Energy

Technology	Scenario	Description	Estimated Range of Revenue*			Comments
			Tipping Fees	Minimum	Maximum	
Renewable Electricity	Option 1a	Commodity Value of Elec + Incentives	\$1,200,000	\$1,000,000	\$2,800,000	Minimum: Sale of commodity plus current market value of LCFS credits. Maximum: Value of commodity plus nominal value of OR CFP credits and eRINs.
	Option 1b	PGE – Small Generator Program	\$1,200,000	\$380,000	\$570,000	Range of \$0.04 - \$0.06/kWh (no wheeling charge).
	Option 1c	Commodity Value + Voluntary Market	\$1,200,000	\$380,000	\$530,000	Range of \$0.05 - \$0.07/kWh unit cost minus 20% transmission wheeling charge from PGE
Renewable Natural Gas	Option 2a	Commodity Value of RNG + Incentives	\$1,200,000	\$2,600,000	\$4,700,000	Minimum: Sale of commodity plus current market value of LCFS credits and RINs. Maximum: Value of commodity plus nominal value of OR CFP credits and RINs. *Assumes all biogas produced is injected to the RNG pipeline, WWTP purchases power and natural gas at retail rate.

Table 3-4. Revenue Potential of Available Options for Tipping Fees and Renewable Energy

Technology	Scenario	Description	Estimated Range of Revenue*			Comments
			Tipping Fees	Minimum	Maximum	
	Option 2b	Sell RNG to NWN	\$1,200,000	\$730,000	\$1,900,000	Minimum: NWN provides gas treatment and NG pipeline interconnection Maximum: Owner provides all infrastructure *Assumes all biogas produced is injected to the RNG pipeline, WWTP purchases power and natural gas at retail rate.
Hybrid Approach (RE/RNG)	Option 3a	Baseload Cogen + Sell Excess RNG	\$1,200,000	\$1,500,000	\$2,600,000	Baseload cogen to provide plant power under current NMA. Minimum: NWN provides gas treatment and NG pipeline interconnection. Maximum: Owner provides all infrastructure.
	Option 3b	Baseload Cogen + Sell Excess RNG to NWN (fixed-price contract)	\$1,200,000	\$380,000	\$1,000,000	Minimum: NWN provides gas treatment and NG pipeline interconnection. Maximum: Owner provides all infrastructure. Baseload cogen to provide plant power under current NMA.

Note: Tipping fees for FOG and food slurry received by the WWTP is estimated at \$0.09 per gallon and \$0.06 per gallon respectively. Range of expected annual operating costs: \$1,400,000 to \$3,200,000.

*Actual total project cost to fall within -50% and 100% of estimated cost.

eRIN = Electric Renewable Identification Number; OR CFP = Oregon Clean Fuels Program; LCFS = Low Carbon Fuel Standards.

Net annual costs were calculated by subtracting the annual operating costs from the capital costs plus annual revenues. To account for costs that would otherwise be required according to the current capital improvements plan, the costs of each alternative were compared to the Baseline option. This allows the payback of each option be separated from the investment that would otherwise be required for routine upgrades and expansions at the facility. Note that the cost of the Baseline option has been revised from the 2020 Feasibility Study (Jacobs, 2020) due to price increases from inflation and supply chain issues in addition to new scope items such as new covers for the existing digesters.

Cashflow projections for each of the revenue generation option are presented in Figures 3-1 through 3-3 and Tables 3-5 through 3-7. The cashflow projections include the expected capital costs of the facilities, which depend on the equipment required. In the case of Options 2b-iii and 3b, the capital offset provided by NWN to cover some or all of the RNG system costs has been included.

3.1.3 Cashflow Payback of Renewable Electricity Options

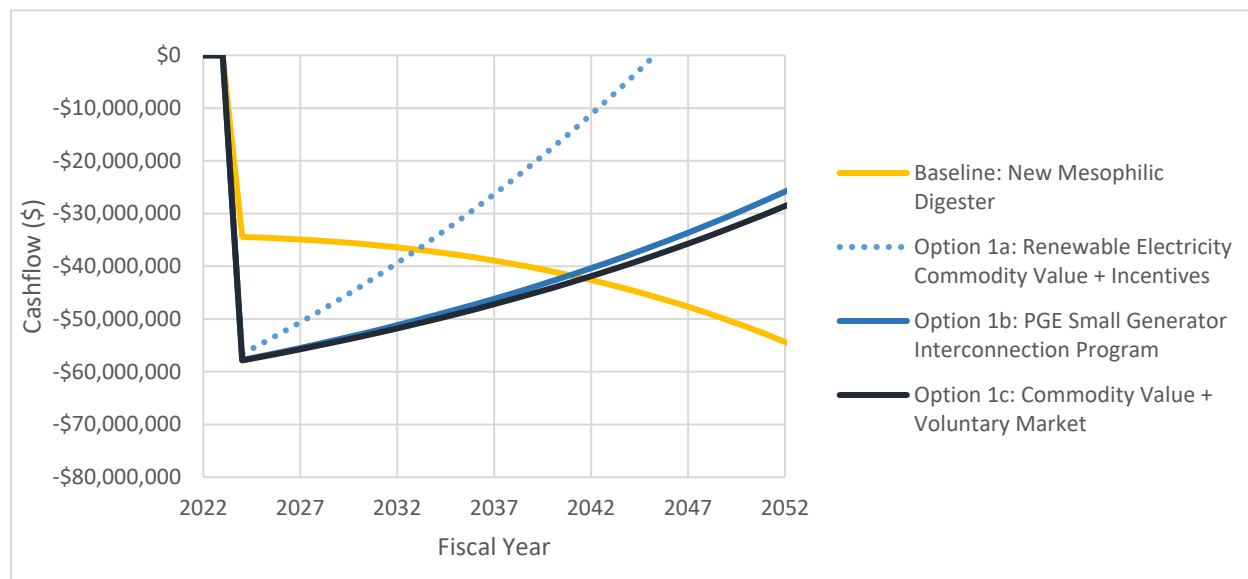


Figure 3-1. Cashflow Payback Projections of RE Options

Table 3-5. Cashflow Breakdown of RE Options

Scenario	Assumptions	Total Capital Costs (\$M)	Total Credits/Grants (\$M)	Total Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food slurry	(\$32.4)	\$0	(\$1.8)	\$0	\$0.4	--
Option 1a: Renewable Electricity Commodity Value + Incentives	Moderate revenue from incentives; nominal value for OR CFP credits and eRINs	(\$55.2)	\$0	(\$2.5)	(\$0.7)	\$2.8	10 years
Option 1b: PGE Small Generator Interconnection Program	Estimated revenue from \$0.05/kWh rate	(\$55.2)	\$0	(\$2.5)	(\$0.7)	\$1.7	17 years
Option 1c: Commodity Value + Voluntary Market	Estimated revenue from \$0.055/kWh rate	(\$55.2)	\$0	(\$2.5)	(\$0.7)	\$1.6	18 years

\$M = million dollars.

Of the three RE options evaluated, sale of the commodity plus incentives projects higher revenues than do the PGE Small Generator Program or sale of the commodity on the voluntary market via long-term contracts.

3.1.4 Cashflow Payback of Renewable Natural Gas Options

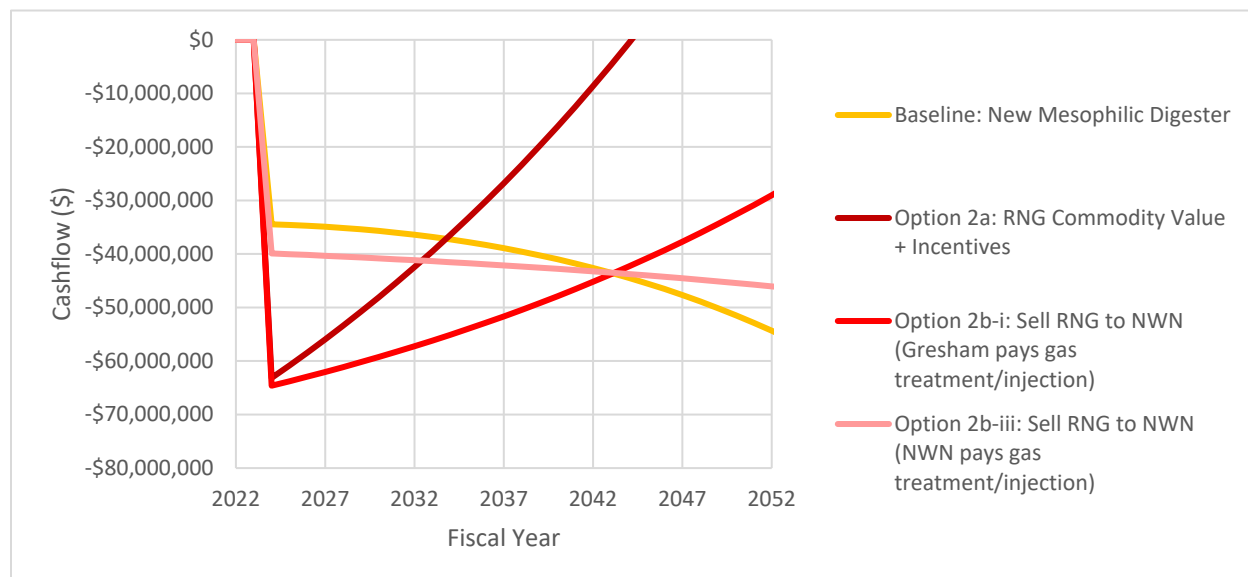


Figure 3-2. Cashflow Payback Projections of RNG Options

Table 3-6. Cashflow Breakdown of RNG Options

Scenario	Assumptions	Total Capital Costs (\$M)	Total Credits/ Grants (\$M)	Total Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food slurry	(\$32.4)	\$0	(\$1.8)	\$0	\$0.4	--
Option 2a: RNG Commodity Value + Incentives	Moderate revenue from incentives	(\$61.7)	\$0	(\$3.7)	(\$1.9)	\$4.5	10 years
Option 2b-i: Sell RNG to NWN (Gresham pays gas treatment/injection)	\$13/MMBtu	(\$61.7)	\$0	(\$3.7)	(\$1.9)	\$3.2	20 years

Table 3-6. Cashflow Breakdown of RNG Options

Option 2b-ii: Sell RNG to NWN (NWN pays gas treatment/ injection)	\$5/MMBtu	(\$37.5)	\$0	(\$3.4)	(\$1.6)	\$2.0	19 years
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\$M = million dollars.

The RNG option that generates the most revenue is also sale of the commodity plus the incentives, rather than entering in long-term, fixed price contracts with NWN. However, the cost of capital is currently high and unpredictable, and the possibility of offsetting those costs by working with NWN reduces risk.

3.1.5 Cashflow Payback of Hybrid Options

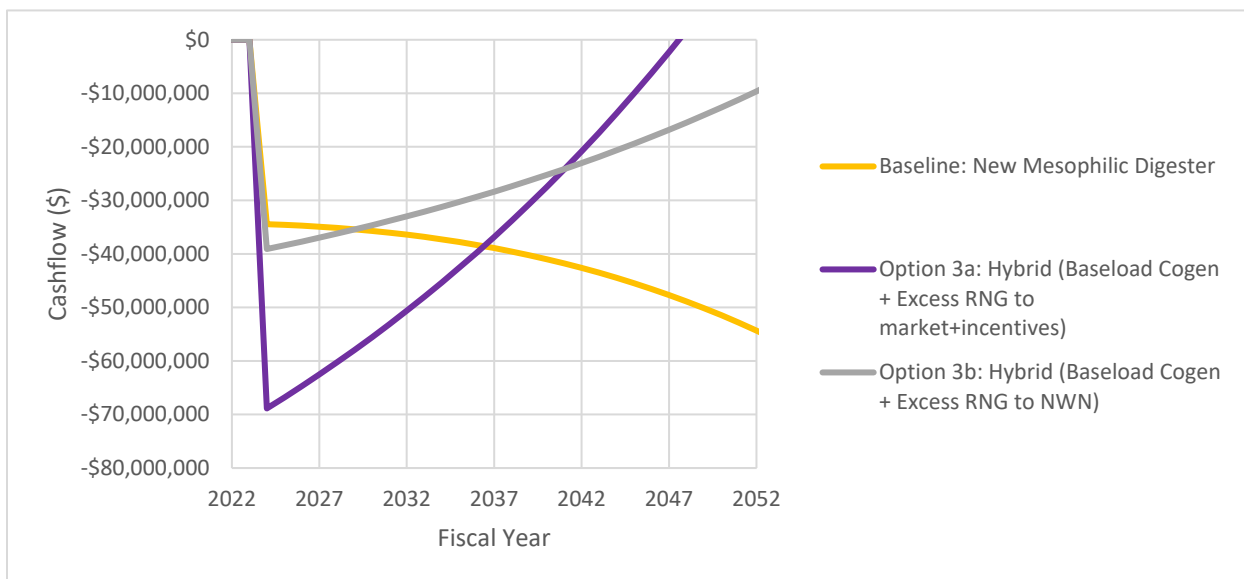


Figure 3-3: Cashflow Payback Projections of Hybrid Options

Table 3-7 includes a summary of the capital costs with the potential revenues.

Table 3-7. Cashflow Breakdown of Hybrid Sub-Options

Scenario	Assumptions	Total Capital Costs (\$M)	Total Credits/ Grants (\$M)	Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Simple Payback
Baseline: New Mesophilic Digester	No add'l FOG/food slurry	(\$32.4)	\$0	(\$1.8)	\$0	\$0.4	--
Option 3a: Hybrid (Baseload Cogen + Excess RNG to	Moderate revenue from incentives	(\$66.8)	\$0	(\$2.4)	(\$0.6)	\$2.8	13 years

Table 3-7. Cashflow Breakdown of Hybrid Sub-Options

market+ incentives)							
Option 3b: Hybrid (Baseload Cogen + Excess RNG to NWN)	\$5/MMBtu	(\$37.5)	\$0	(\$2.4)	(\$0.6)	\$1.6 mil	6 years

Actual total project cost to fall within -50% and 100% of estimated cost.

\$M = million dollars.

The Hybrid Option 3b meets lifecycle cost parity with the Baseline Option faster than 3a due to its substantially lower capital cost due to the waiver of the \$2.5 million interconnection charge and the procurement of the RNG Upgrading Skid by NWN. Revenue generation is fixed, however, and less than projected market returns. Option 3a is the more aggressive approach to maximize revenue, but certainly entails more risk downside than a fixed price contract with capital improvements support included.

3.1.6 Comparison of RE, RNG, and Hybrid Options

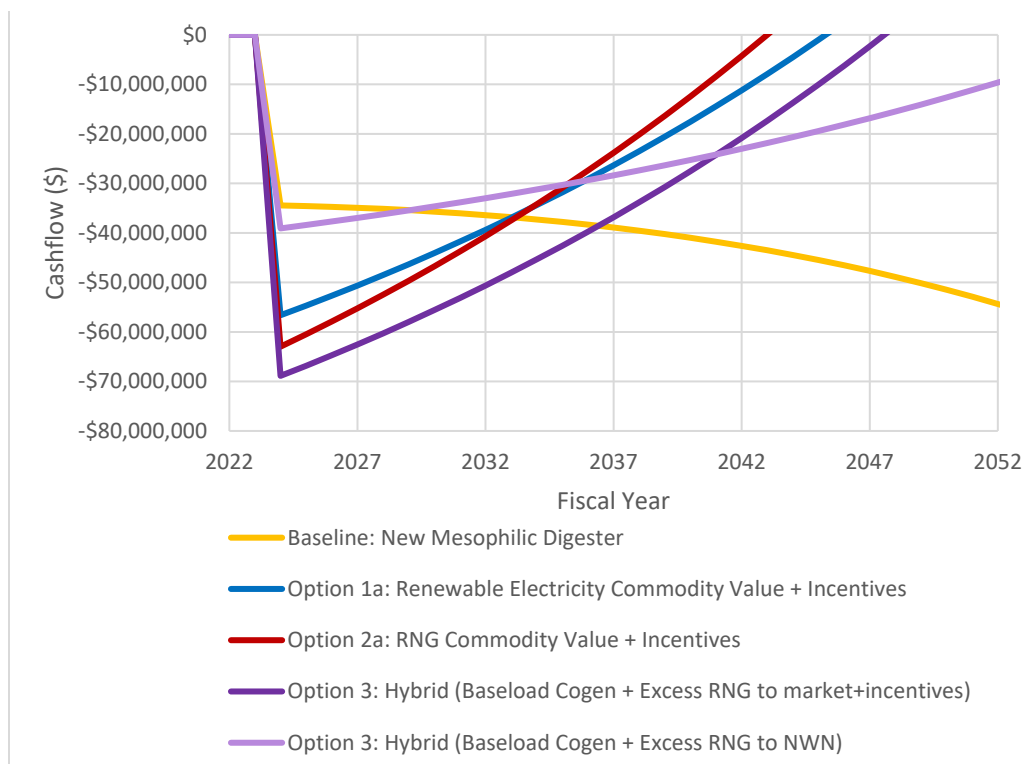


Figure 3-4. Comparison between the Revenue Generating Options (highest generating sub-options shown)

Table 3-8 includes a summary of the capital costs with the potential revenues for the most promising options.

Table 3-8. Cashflow Breakdown of Most Promising Revenue Generating Sub-options

Scenario	Assumptions	Total Capital Costs	Total Credits/Grants (\$M)	Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Simple Payback
Baseline: New Mesophilic Digester	No add'l FOG/food slurry	(\$32.4)	\$0	(\$1.8)	\$0	\$0.4	--
Option 1a: Renewable Electricity Commodity Value + Incentives	Moderate revenue from incentives; nominal value for OR CFP credits and eRINs	(\$55.2)	\$0	(\$2.5)	(\$0.7)	\$2.8	10 years
Option 2a: RNG Commodity Value + Incentives	Moderate revenue from incentives	(\$61.7)	\$0	(\$3.8)	(\$2.0)	\$4.5	10 years
Option 3a: Hybrid (Baseload Cogen + Excess RNG to market incentives)	Moderate revenue from incentives	(\$66.8)	\$0	(\$2.4)	(\$0.6)	\$2.8	13 years
Option 3b: Hybrid (Baseload Cogen + Excess RNG to NWN)	\$5/MMBtu	(\$37.5)	\$0	(\$2.4)	(\$0.6)	\$1.6	6 years

\$M = million dollars.

The Hybrid Option 3b offers the fastest potential payback by virtue of much lower starting capital requirements, although all of the other options eventually exceed the revenue produced by it. Option 3b also entails lower risk, due to the fixed price contract. Also, the system offers much greater flexibility. Staff would be able to shift biogas flow from base-loading the CHP system to the RNG Upgrading System for cleaning to pipeline quality during times where plant power and heat demand are lower than normal to maximize revenue.

3.2 Non-Monetary Evaluation

A non-monetary evaluation was performed to compare each alternative based on key criteria identified by Jacobs in concert with the City. Each criterion was assigned a weighting value based on its relative importance. Each criterion was then given a score between 1 (lowest) and 10 (highest) for the three options being considered: RE, RNG, and Hybrid Approach.

The results of the non-monetary weightings and scoring are shown in Table 3-9.

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Table 3-9. Non-monetary Criteria, Weightings and Scoring

Drivers/ Evaluation Criteria	Weight	Maximum Possible Score	3 Mesophilic Digesters (Baseline Option)	Renewable Electricity: Commodity Value + Incentives (Option 1a)	Renewable Natural Gas: Commodity Value + Incentives (Option 2a)	Hybrid Approach: Baseload Cogen + Sell Excess RNG (Option 3a)	Definitions
Reliability	25	10	7	6	7	9	Equipment reliability, equipment downtime, and consistent operation. Tendency for minimal failure resulting in downtime.
Redundancy	20	10	4	8	8	9	Major equipment redundancy.
Ease of operation and maintenance	15	10	8	6	7	4	Operational complexity for operation of units includes amount of training needed and number and complexity of mechanical equipment. Maintenance complexity includes quantity of parts involved and specialized equipment, training, and steps needed to perform the work.
Biosolids quality (Class A)	10	10	3	4	4	4	Class A provides regulatory compliance surety and mitigate risk.
Biosolids quantity (trucking/stora ge)	10	10	6	4	4	4	Storage requirements and production of greenhouse gases associated with trucking operations.
Sustainability	5	10	1	9	9	9	Overall sustainability by accepting food slurry and with regards to energy consumption.
Net zero – energy efficiency	15	10	3	10	1	10	Ability to remain net zero in energy usage.
Non-monetary weighted total score		100	52	68	58	74	

3.3 Sensitivity Analysis

The costs included in business case evaluations can be impacted to different degrees by changes to the following parameters:

- Grant/funding potential
- Incentive values/range of potential revenues (upside or downside)
- Regulatory changes via the Proposed RFS (eRINs and D3/D5 differentiation for co-digestion)
- Uncertain labor market that impacts O&M costs
- Capital cost volatility/inflation

The following section presents some examples of how the BCE is sensitive to changes in the cost parameters. This is accomplished in the sensitivity analysis by modifying the parameters listed above, but otherwise maintaining the base assumptions.

3.3.1 Grant and/or Funding Potential

There are several opportunities to mitigate capital costs and reduce the payback scenarios. These include the following:

- Grants/tax credits
- Inflation Reduction Act of 2022
- Energy Trust of Oregon
- State Revolving Fund loans
- Infrastructure Investment and Jobs Act Funding
- Others: Oregon Department of Energy, etc.

The first parameter evaluated was the impact to the payback scenarios by reducing the capital costs. The scenario included the maximum revenue generation potential coupled with grant funding. This scenario represents the most optimistic option and is summarized in Figure 3-5 and Table 3-10.

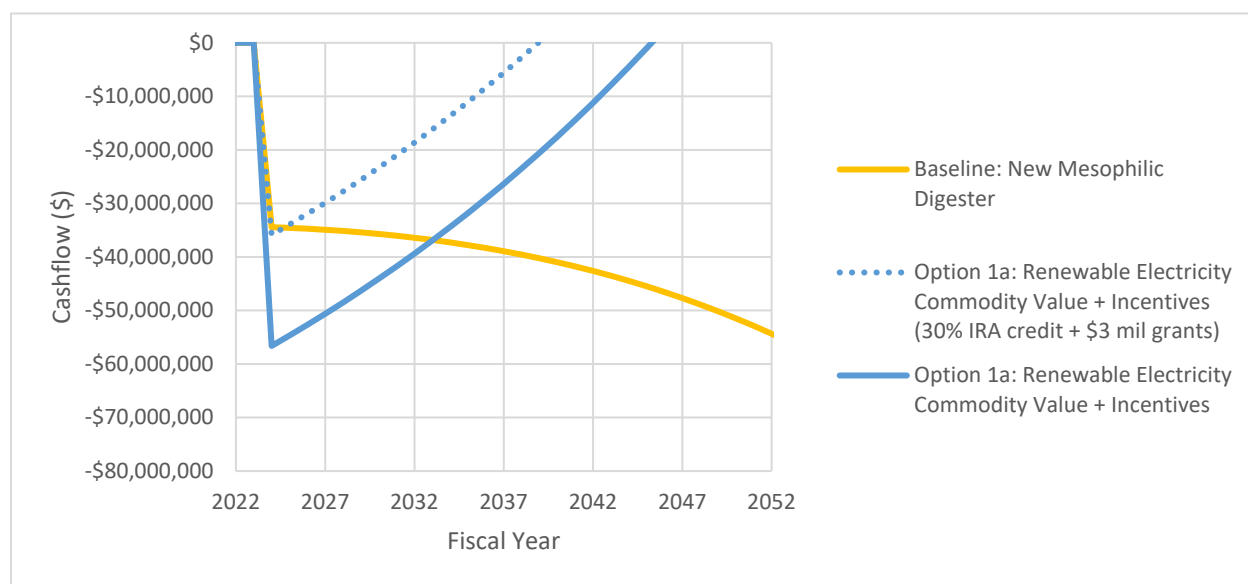


Figure 3-5. Sensitivity of RE Option 1a to Grant Funding

Table 3-10. Cashflow Breakdown of RE Option – Sensitivity to Grant Funding

Scenario	Assumptions	Total Capital Costs (\$M)	Total Credits/ Grants (\$M)	Total Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food slurry	(\$32.4)	\$0	(\$1.8)	\$0	\$0.4	--
Option 1a: Renewable Electricity Commodity Value + Incentives	Moderate revenue from incentives; nominal value for OR CFP credits and eRINs	(\$55.2)	\$0	(\$2.5)	(\$0.6)	\$2.8	10 years
Option 1a: Renewable Electricity Commodity Value + Incentives (30% IRA credit + \$3M grants)	Estimated revenue from \$0.05/kWh rate	(\$35.6)	\$19.6	(\$2.5)	(\$0.6)	\$2.8	1 year

\$M = million dollars.

The impact of attaining substantial grant funding through the Inflation Reduction Act and other sources is clearly demonstrated in the figure above, reducing project payback versus baseline to 1 year in the case of renewable electricity. The impacts on the RNG and hybrid options are analogous, with payback periods being reduced to between 1 and 5 years.

The range of potential incentive values is also a source of uncertainty that will influence payback cashflow. The OR CFP is relatively new and has yet to develop a fully liquid market. Future market values of incentives are unknown and may be lower than expected. Figure 3-6 and Table 3-11 present the range of potential cashflow curves based on currently projected incentive values (high- to low-range).

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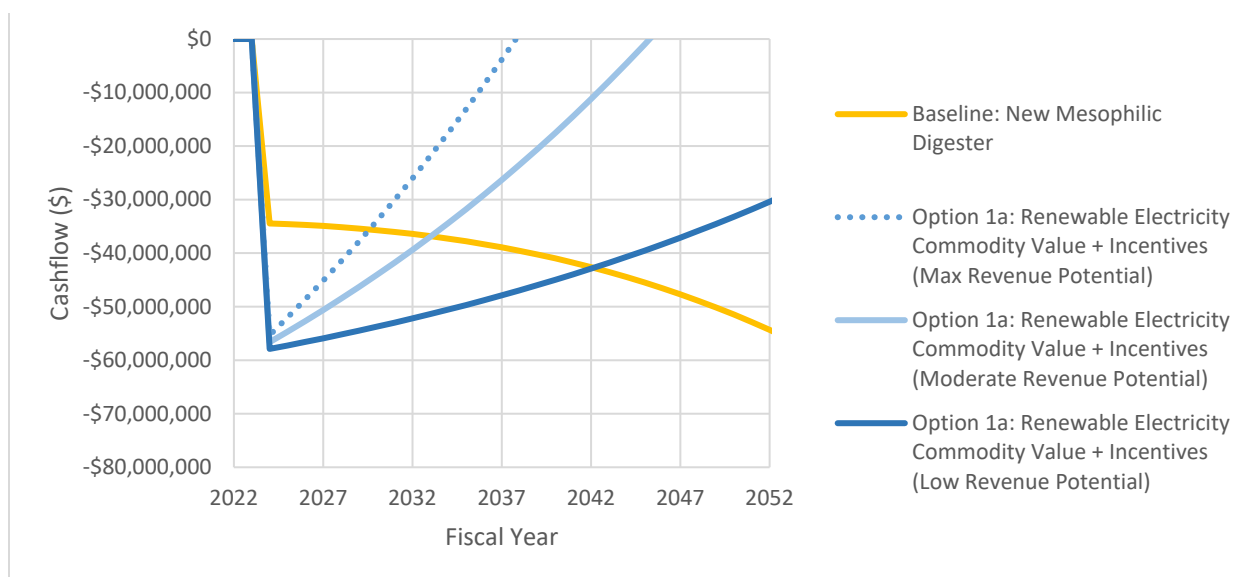


Figure 3-6. Sensitivity of RE Options to Range of Projected Incentive Values

Table 3-11 Cashflow Breakdown of RE Option – Sensitivity to Incentive Value

Scenario	Assumptions	Total Capital Costs (\$M)	Total Credits/Grants (\$M)	Total Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Simple Payback vs Baseline
Baseline: New Mesophilic Digester	No add'l FOG/food slurry	(\$32.4)	\$0	(\$1.8)	\$0	\$0.4	--
Option 1a: Renewable Electricity Commodity Value + Incentives (Max Revenue Potential)	Maximum revenue from incentives; nominal value for OR CFP credits and eRINs	(\$55.2)	\$0	(\$2.5)	(\$0.7)	\$4.0	6 years
Option 1a: Renewable Electricity Commodity Value + Incentives (Moderate Revenue Potential)	Moderate revenue from incentives; nominal value for OR CFP credits and eRINs	(\$55.2)	\$0	(\$2.5)	(\$0.7)	\$2.8	10 years

Table 3-11 Cashflow Breakdown of RE Option – Sensitivity to Incentive Value

Scenario	Assumptions	Total Capital Costs (\$M)	Total Credits/Grants (\$M)	Total Annual Operating Costs (\$M)	Annual Operating Costs vs Baseline (\$M)	Annual Revenue (\$M)	Estimated Simple Payback vs Baseline
Option 1a: Renewable Electricity Commodity Value + Incentives (Low Revenue Potential)	Minimum revenue from incentives; nominal value for OR CFP credits, no eRINs	(\$55.2)	\$0	(\$2.5)	(\$0.7)	\$1.6	19 years

\$M = million dollars.

The sensitivity of RNG to incentive values is analogous. In the case of RNG, however, long-term, fixed-price contracts with NWN can provide revenue stability at a reasonable payback rate, especially considering the funding that NWN offers to provide if the RNG price is set at a lower rate.

3.3.2 Regulatory Changes

The Proposed RFS indicates priority at the federal level to encourage investment in renewable energy. The recognition of eRINs and the differentiation of D3/D5 RINs from co-digested material, if enacted, would significantly increase the revenue from either RE, RNG, or Hybrid options at Gresham. Indications are strong that the Proposed RFS will move forward through 2025, but future rule changes that could impact these are impossible to foresee. Figures 3-7 through 3-9 below illustrate the impact that the changes in the Proposed RFS could have on each of the options.

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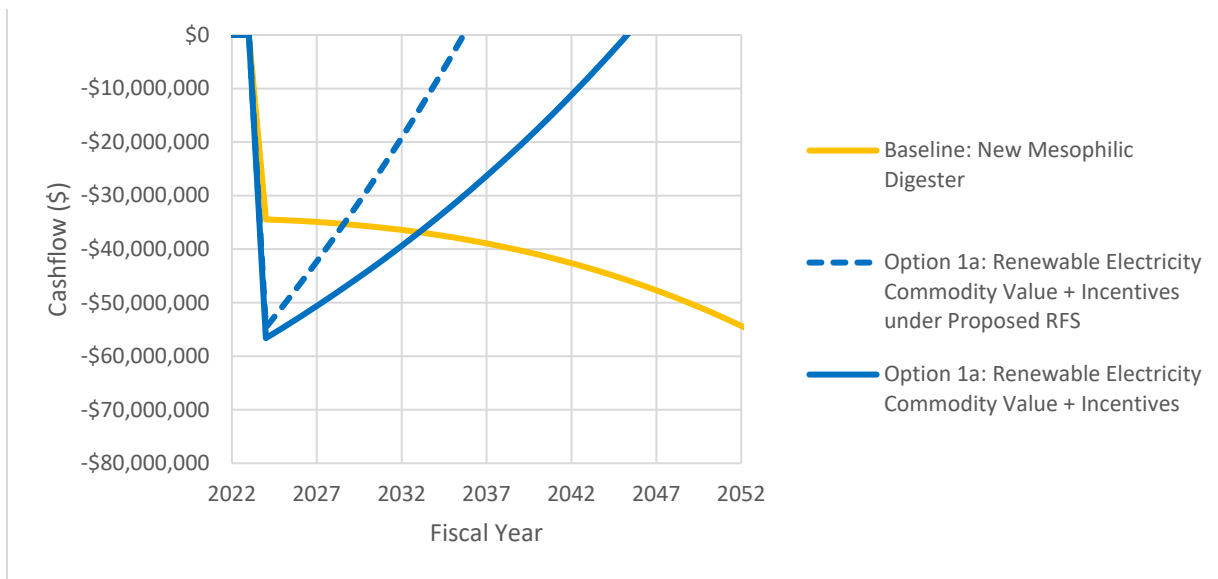


Figure 3-7. Impact of Proposed RFS on RE Option 1a

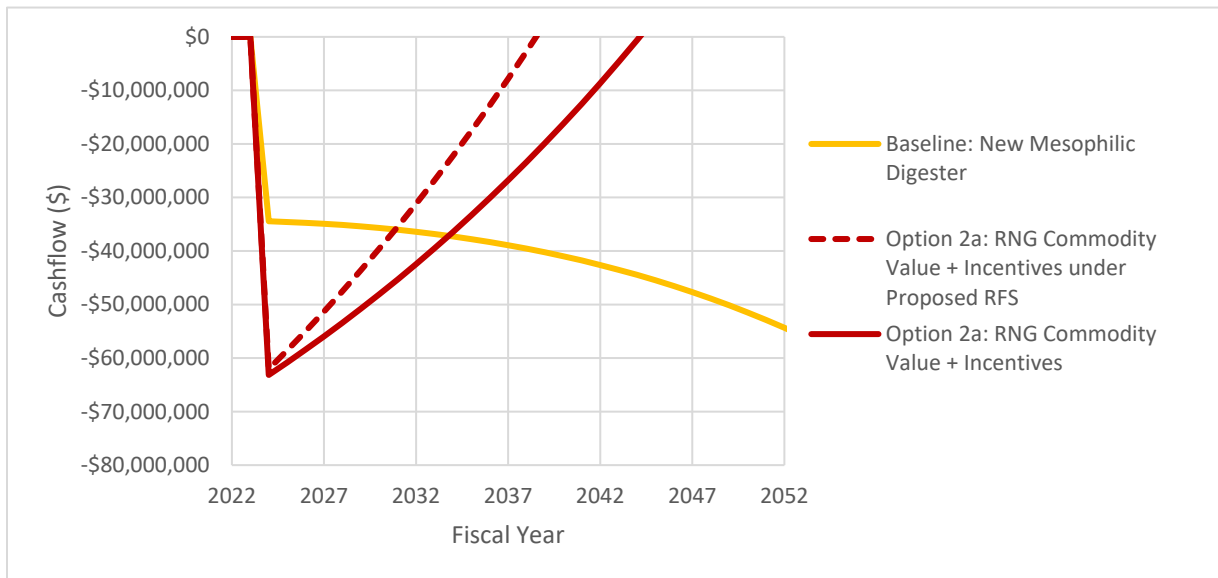


Figure 3-8. Impact of Proposed RFS on RNG Option 2a

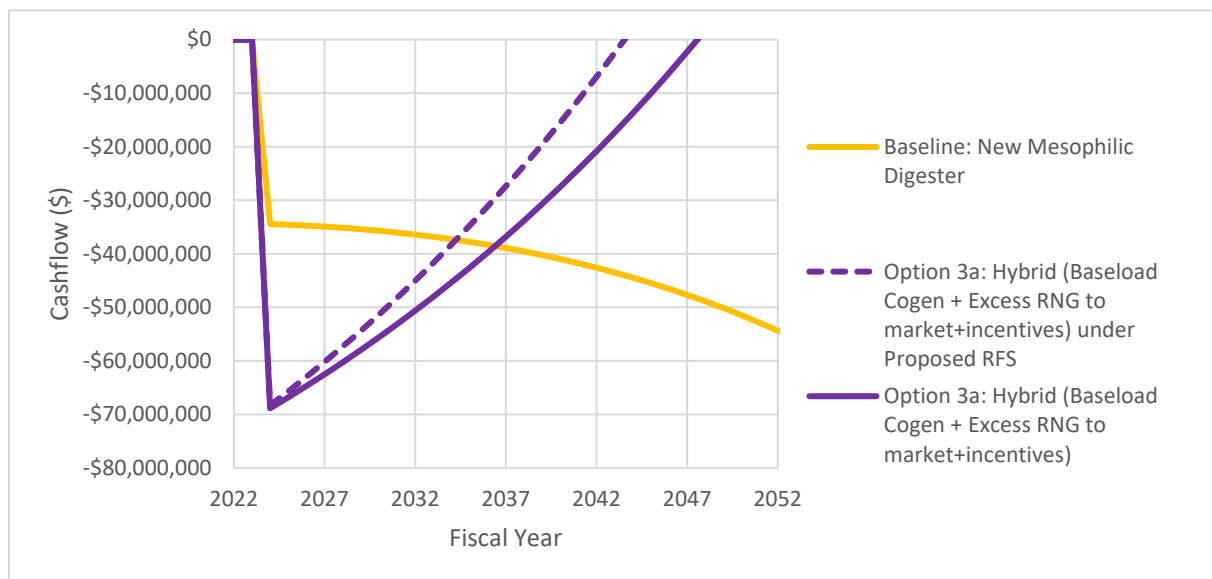


Figure 3-9. Impact of Proposed RFS on Hybrid Option 3a

The impact of proposed regulatory changes is most significant for RE, because the compounding effect of the change in equivalency rate for eRINs and the proposed differentiation of D3/D5 RINs from co-digestion. The proposed change will accelerate the cashflow payback period for RE by 4 years, for RNG by 3 years, and for the Hybrid option by 2 years.

3.4 Business Case Findings

A comparison of the non-monetary benefit scores with the life cycle and payback results of each of the three alternatives are shown in Figures 3-10 and 3-11, respectively. For both these figures the best value for the City is the lowest cost and highest benefit score, which is located in the top left part of the graph. In Figure 3-10, the life cycle costs are lower for all three alternatives relative to the base case and have higher benefit scores, with Option 3 – Hybrid having the highest benefit score which comes at the cost of having increased capital costs associated with building and maintaining both RE and RNG systems. In Figure 3-11, the payback for Option 1 - RE and Option 2 – RNG are both 10 years whereas the payback for Option 3 – Hybrid is slightly higher at 13 years but again has the highest benefit score.

The BCE has demonstrated that each option contains at least one pathway to viability, which can be defined as generating sufficient annual cashflow to offset the initial extra capital expense compared to the Baseline Option. In general, the three primary options fall within a relatively narrow band of revenue generation potential. Renewable electricity Option 1a could generate the most revenue but relies on the adoption and continued support for eRINs, which are not yet enacted. Renewable natural gas options offer the potential for capital offset and fixed prices contracts with NWN, but by requiring the plant to buy retail electricity and natural gas, they would reverse the plant's achievement of Net Zero energy. The Hybrid Option would allow the plant to diversify energy markets and would provide the most redundancy but would also involve the largest capital expenditure and the highest operating costs.

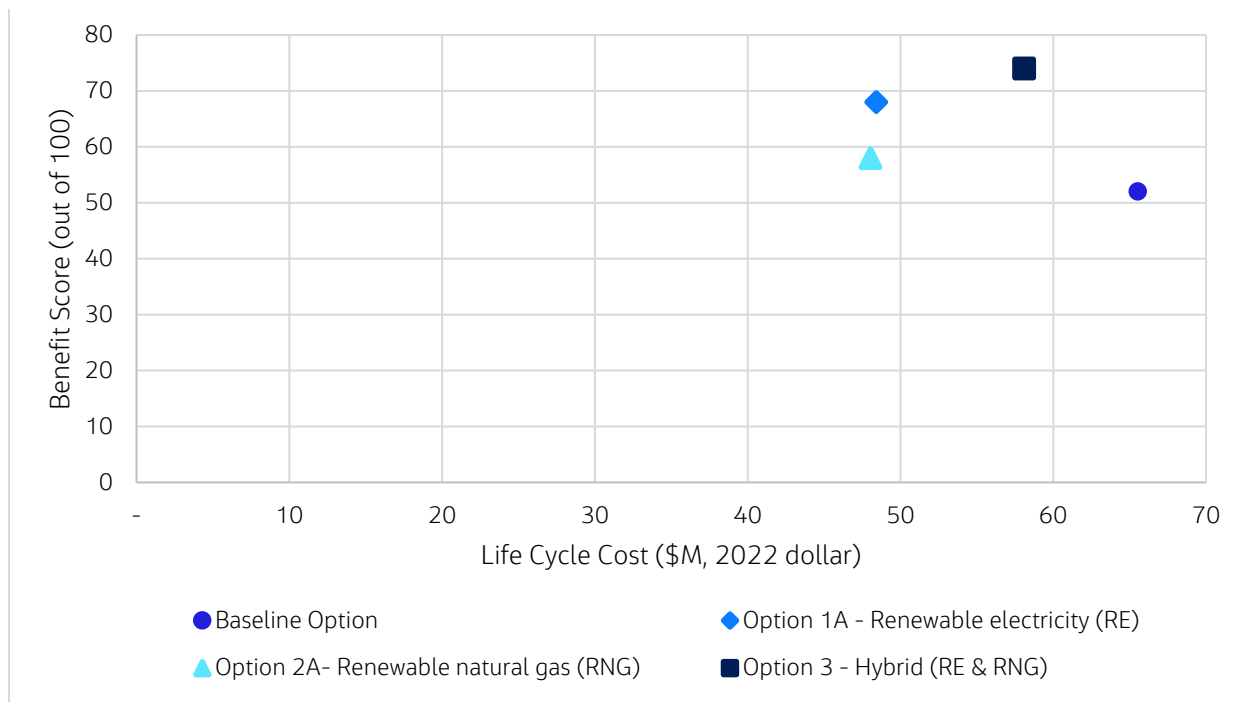


Figure 3-10 Comparison of Benefit Score to Life Cycle Costs

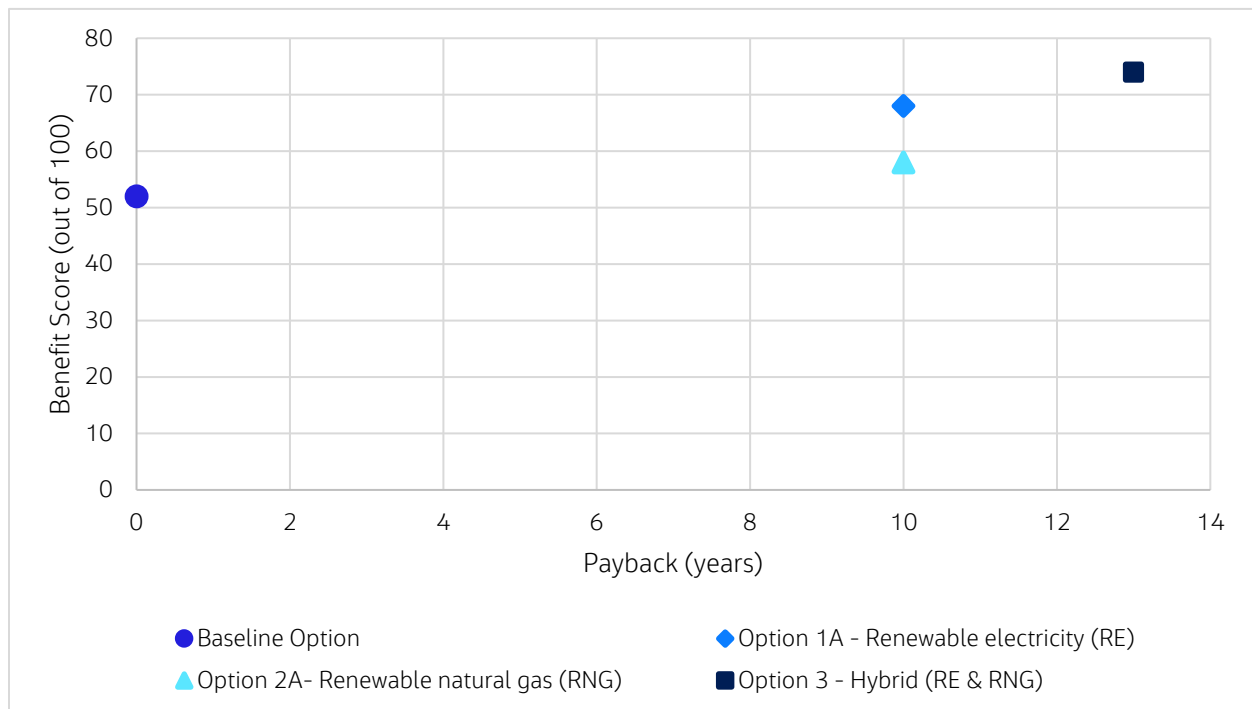


Figure 3-11 Comparison of Benefit Score to Payback

4. Summary and Conclusions

At project Workshop 1, the City chose to proceed with Option 3: Hybrid approach for the following reasons:

- The renewable energy credit markets are under development and many of the assumptions herein may continue needing to be revised. The sensitivity analyses presented in this memorandum demonstrate that the path the City chooses—RE, RNG, or some combination—is highly sensitive to these credit markets. So having the flexibility of remaining open to a hybrid solution is of high value at this time.
- The additional project costs and therefore slightly reduced payback associated with the hybrid approach relative to only RE or only RNG are not significant enough to outweigh the value of the Hybrid Option as discussed above.

The City has the ability to phase in the capital improvements based on funding and to further allow the renewable energy credit programs (both state and federal) to mature and possibly become more certain. For example, the City might proceed with the redundant digester which provides solids stabilization redundancy as well as the ability to receive additional outside high strength wastes and defer the cogeneration expansion and/or the RNG infrastructure until more clarity is reached.

5. References

Association for the Advancement of Cost Engineering International (AACE). 2011. *Recommended Practice No. 18R-97, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries*.

CH2M. 2017. *Wastewater Treatment Plant Master Plan Update 2017*. October.

Jacobs. 2020. *Feasibility Study of Expanding Liquid Organic Digestion Capacity, CIP 322100*. Prepared for the City of Gresham.

Appendix A. Process Mass Balance

		Mesophilic Digestion (MAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
Feed to Digesters, WW Solids + Current FOG																
WW Solids Load	lb TS/day	34,071	41,046	41,755	35,965	43,329	44,076	37,860	45,611	46,398	39,754	47,893	48,720	41,649	50,176	51,042
WW Solids Load	lb TS/day rounded	34,100	41,000	41,800	36,000	43,300	44,100	37,900	45,600	46,400	39,800	47,900	48,700	41,600	50,200	51,000
WW Solids VS/TS Ratio	%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%
WW Solids Volatile Loading	lb VS/day	27,938	33,658	34,239	29,492	35,529	36,143	31,045	37,401	38,047	32,599	39,273	39,951	34,152	41,144	41,854
WW Solids Volatile Loading	lb VS/day rounded	27900	33700	34200	29500	35500	36100	31000	37400	38000	32600	39300	40000	34200	41100	41900
Digester Feed WW Solids Concentration	%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
WW Solids Flow to Digesters	gpd	74,277	89,484	91,028	78,407	94,460	96,090	82,537	99,435	101,152	86,668	104,411	106,214	90,798	109,387	111,275
WW Solids Flow to Digesters	gpd rounded	74,300	89,500	91,000	78,400	94,500	96,100	82,500	99,400	101,200	86,700	104,400	106,200	90,800	109,400	111,300
WW Solids Flow to Digesters	gpm	52	62	63	54	66	67	57	69	70	60	73	74	63	76	77
FOG Solids Volatlle Loading	lb VS/day	8,676	11,256	11,459	8,676	11,256	11,459	8,676	11,256	11,459	8,676	11,256	11,459	8,676	11,256	11,459
FOG Solids Flow to Digesters	gpd	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660
FOG Solids Flow to Digesters	gpm	8.1	9.6	10.2	8.1	9.6	10.2	8.1	9.6	10.2	8.1	9.6	10.2	8.1	9.6	10.2
FOG Solids VS Concentration	% VS	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
FOG Solids TS Concentration	% TS	11.2%	12.1%	11.7%	11%	12%	12%	11%	12%	12%	11%	12%	12%	11%	12%	12%
Total WW Solids & current FOG VS Loading	lb VS/day	36,614	44,914	45,698	38,168	46,786	47,602	39,721	48,657	49,506	41,275	50,529	51,410	42,828	52,401	53,313
Total WW Solids & current FOG TS Loading	lb TS/day	43,137	52,808	53,729	45,031	55,091	56,050	46,926	57,373	58,372	48,820	59,656	60,694	50,715	61,938	63,016
Total WW Solids & current FOG VS Flow	gpd	85,871	103,366	105,688	90,001	108,342	110,750	94,132	113,318	115,812	98,262	118,294	120,873	102,392	123,270	125,935
Total WW Solids & current FOG VS Flow	gpm	60	72	73	63	75	77	65	79	80	68	82	84	71	86	87
Anaerobic Digestion																
Digester 1 Volume (existing)	MG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Digester 2 Volume (existing)	MG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Digester 3 Volume (new)	MG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
WW Solids VSR	%	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%
FOG VSR	%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
WW Solids Volatile Solids Destroyed	lb VSR/day	16,204	19,522	19,859	17,105	20,607	20,963	18,006	21,693	22,067	18,907	22,778	23,171	19,808	23,864	24,276
Current FOG Volatile Solids Destroyed	lb VSR/day	8,242	10,693	10,886	8,242	10,693	10,886	8,242	10,693	10,886	8,242	10,693	10,886	8,242	10,693	10,886
WW+current FOG Volatile Solids Destroyed	lb VSR/day	24,446	30,215	30,745	25,347	31,301	31,849	26,248	32,386	32,953	27,150	33,472	34,057	28,051	34,557	35,162
WW+current FOG Volatile Solids Destruction	%	67%	67%	67%	66%	67%	67%	66%	67%	67%	66%	66%	66%	65%	66%	66%
WW + current FOG Volatile Solids After Digestion	lb VS/day	12,168	14,699	14,953	12,820	15,485	15,753	13,473	16,271	16,553	14,125	17,057	17,352	14,778	17,843	18,152
WW + current FOG Total Solids After Digestion	lb TS/day	18,690	22,593	22,984	19,684	23,790	24,202	20,677	24,987	25,419	21,671	26,184	26,637	22,664	27,381	27,854
SOLIDS CAPACITY CHECK																
Max VSLR	lb VS/day-cf	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20	0.25
VSLR (WW+current FOG), 3 Digesters	lb VS/day-cf	0.091	0.112	0.114	0.095	0.117	0.119	0.099	0.121	0.123	0.103	0.126	0.128	0.107	0.131	0.133
VSLR (WW+current FOG), 2 Digesters	lb VS/day-cf	0.104	0.126	0.128	0.110	0.133	0.135	0.116	0.140	0.142	0.122	0.147	0.149	0.128	0.154	0.157
VSLR (WW+current FOG), 1 Digester	lb VS/day-cf	0.209	0.252	0.256	0.221	0.266	0.270	0.232	0.280	0.285	0.244	0.294	0.299	0.255	0.308	0.313
Max Solids Loading, 3 Digesters	lb VS/day	80,214	80,214	100,267	80,214	80,214	100,267	80,214	80,214	100,267	80,214	80,214	100,267	80,214	80,214	100,267
Max Solids Loading, 2 Digesters	lb VS/day	53,476	53,476	66,845	53,476	53,476	66,845	53,476	53,476	66,845	53,476	53,476	66,845	53,476	53,476	66,845
Max Solids Loading, 1 Digester	lb VS/day	26,738	26,738	33,422	26,738	26,738	33,422	26,738	26,738	33,422	26,738	26,738	33,422	26,738	26,738	33,422
HYDRAULIC CAPACITY CHECK																
Minimum SRT	days	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
SRT (WW+current FOG), 3 Digesters	days	34.9	29.0	28.4	33.3	27.7	27.1	31.9	26.5	25.9	30.5	25.4	24.8	29.3	24.3	23.8
SRT (WW+current FOG), 2 Digesters	days	23.3	19.3	18.9	22.2	18.5	18.1	21.2	17.6	17.3	20.4	16.9	16.5	19.5	16.2	15.9
SRT (WW+current FOG), 1 Digester	days	11.6	9.7	9.5	11.1	9.2	9.0	10.6	8.8	8.6	10.2	8.5	8.3	9.8	8.1	7.9
Max Hydraulic Flow to Digesters, 3 Digesters	gpm	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
Max Hydraulic Flow to Digesters, 2 Digesters	gpm	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
Max Hydraulic Flow to Digesters, 1 Digester	gpm	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
SELR CHECK																
Max SELR	lb COD/lb VS-day	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
COD - WW Solids	lb COD/lb VS	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
COD - FOG	lb COD/lb VS	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
COD Added - WW Solids	lb COD/day	41,907	50,487	51,358	44,237	53,294	54,214	46,568	56,102	57,070	48,898	58,909	59,926	51,228	61,716	62,782
COD Added - FOG	lb COD/day	25,161	32,643	33,231	25,161	32,643	33,231	25,161	32,643	33,231	25,161	32,643	33,231	25,161	32,643	33,231
Digester VS Inventory, WW+FOG, 3 Digesters	lb VSinv Total	425,094	426,613	424,455	427,335	428,786	426,716	429,380	430,768	428,779	431,252	432,584	430,670	432,974	434,253	432,409
Digester VS Inventory, WW+FOG, 2 Digesters	lb VSinv Total	283,396	284,409	282,970	284,890	285,857	284,477	286,253	287,179	285,853	287,502	288,389	287,113	288,649	289,502	288,273
Digester VS Inventory, WW+FOG, 1 Digester	lb VSinv Total	141,698	142,204	141,485	142,445	142,929	142,239	143,127	143,589	142,926	143,751	144,195	143,557	144,325	144,751	144,136
SELR, 3 Digesters	lb COD/lb VSinv-day	0.158	0.195	0.199	0.162	0.200	0.205	0.167	0.206	0.211	0.172	0.212	0.216	0.176	0.217	0.222
SELR, 2 Digesters	lb COD/lb VSinv-day	0.237	0.292	0.299	0.244	0.301	0.307	0.251	0.309	0.316	0.258	0.317	0.324	0.265	0.326	0.333
SELR, 1 Digester	lb COD/lb VSinv-day	0.473	0.585	0.598	0.487	0.601	0.615	0.501	0.618	0.632	0.515	0.635	0.649	0.529	0.652	0.666

		Mesophilic Digestion (MAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
EXTRA FEEDSTOCK DIGESTION																
Mass of Additional FOG Added to Digesters	wet tons/yr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solids Content Hauled to WWTP - Addt'l FOG	% TS	11%	12%	12%	11%	12%	12%	11%	12%	12%	11%	12%	12%	11%	12%	12%
FOG VS Content	% VS	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
Addt'l FOG TS Added to Digestion	lb TS/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Addt'l FOG VS Added to Digestion	lb VS/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Volume of Addt'l FOG Added to Digestion	gpd	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VSR - FOG	% VSR	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Addt'l FOG Volatile Solids Reduced	lb VSR/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mass of Food Waste Added to Digesters	wet tons/yr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solids Content Hauled to WWTP - FW	% TS	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Food Waste VS Content	% VS	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%
Food Waste TS Added to Digestion	lb TS/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Food Waste VS Added to Digestion	lb VS/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mass of Food Waste Hauled to WWTP	wet ton/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Volume of Food Waste Hauled to WWTP	gal/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Volume of Food Waste Hauled to WWTP	gal/yr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solids Content into Digester - FW	% TS	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Volume into Digester - FW	gpd	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VSR - FW	%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
FW Volatile Solids Destroyed	lb VSR/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Volume of FW and FOG added to Digesters	gpd	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660
Total Volume Added to Digesters, WW Solids + FOG + FW	gpd	85,871	103,366	105,688	90,001	108,342	110,750	94,132	113,318	115,812	98,262	118,294	120,873	102,392	123,270	125,935
Volatile Solids After Digestion	lb VS/day	12,168	14,699	14,953	12,820	15,485	15,753	13,473	16,271	16,553	14,125	17,057	17,352	14,778	17,843	18,152
Total Solids After Digestion	lb TS/day	18,690	22,593	22,984	19,684	23,790	24,202	20,677	24,987	25,419	21,671	26,184	26,637	22,664	27,381	27,854
Addl FOG/FW After Digestion	lb TS/day															
SOLIDS CAPACITY CHECK w/FW																
Max VSLR	lb VS/day-cf	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20	0.25
VSLR, 3 Digesters	lb VS/day-cf	0.091	0.112	0.114	0.095	0.117	0.119	0.099	0.121	0.123	0.103	0.126	0.128	0.107	0.131	0.133
VSLR, 2 Digesters	lb VS/day-cf	0.137	0.168	0.171	0.143	0.175	0.178	0.149	0.182	0.185	0.154	0.189	0.192	0.160	0.196	0.199
VSLR, 1 Digester	lb VS/day-cf	0.274	0.336	0.342	0.285	0.350	0.356	0.297	0.364	0.370	0.309	0.378	0.385	0.320	0.392	0.399
Max Solids Loading, 3 Digesters	lb VS/day	80,214	80,214	100,267	80,214	80,214	100,267	80,214	80,214	100,267	80,214	80,214	100,267	80,214	80,214	100,267
Max Solids Loading, 2 Digesters	lb VS/day	53,476	53,476	66,845	53,476	53,476	66,845	53,476	53,476	66,845	53,476	53,476	66,845	53,476	53,476	66,845
Max Solids Loading, 1 Digester	lb VS/day	26,738	26,738	33,422	26,738	26,738	33,422	26,738	26,738	33,422	26,738	26,738	33,422	26,738	26,738	33,422
HYDRAULIC CAPACITY CHECK w/FW																
Minimum SRT	days	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
SRT, 3 Digesters	days	34.9	29.0	28.4	33.3	27.7	27.1	31.9	26.5	25.9	30.5	25.4	24.8	29.3	24.3	23.8
SRT, 2 Digesters	days	23.3	19.3	18.9	22.2	18.5	18.1	21.2	17.6	17.3	20.4	16.9	16.5	19.5	16.2	15.9
SRT, 1 Digester	days	11.6	9.7	9.5	11.1	9.2	9.0	10.6	8.8	8.6	10.2	8.5	8.3	9.8	8.1	7.9
Max Hydraulic Flow to Digesters, 3 Digesters	gpm	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
Max Hydraulic Flow to Digesters, 2 Digesters	gpm	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
Max Hydraulic Flow to Digesters, 1 Digester	gpm	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
SELR CHECK																
Max SELR (Target of 0.3, max of 0.5)	lb COD/lb VS-day	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
COD - WW Solids	lb COD/lb VS	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
COD - FOG	lb COD/lb VS	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
COD - FW	lb COD/lb VS	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76
COD Added - WW Solids	lb COD/day	42,502	51,203	52,087	44,865	54,051	54,983	47,228	56,898	57,880	49,592	59,745	60,776	51,955	62,592	63,673
COD Added - FOG	lb COD/day	25161	32643	33231	25161	32643	33231	25161	32643	33231	25161	32643	33231	25161	32643	33231
COD Added - FW	lb COD/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Percent of Total COD Added as FOG	%	37%	39%	39%	36%	38%	38%	35%	36%	36%	34%	35%	35%	33%	34%	34%
Percent of WW Solids COD Added as FOG	%	59%	64%	64%	56%	60%	60%	53%	57%	57%	51%	55%	55%	48%	52%	52%
Digester VS Inventory, WW+FOG+FW, 3 Digesters	lb VSinv Total	425,094	426,613	424,455	427,335	428,786	426,716	429,380	430,768	428,779	431,252	432,584	430,670	432,974	434,253	432,409
Digester VS Inventory, WW+FOG+FW, 2 Digesters	lb VSinv Total	283,396	284,409	282,970	284,890	285,857	284,477	286,253	287,179	285,853	287,502	288,389	287,113	288,649	289,502	288,273
Digester VS Inventory, WW+FOG+FW, 1 Digester	lb VSinv Total	141,698	142,204	141,485	142,445	142,929	142,239	143,127	143,589	142,926	143,751	144,195	143,557	144,325	144,751	144,136
SELR, 3 Digesters	lb COD/lb VSinv-day	0.159	0.197	0.201	0.164	0.202	0.207	0.169	0.208	0.212	0.173	0.214	0.218	0.178	0.219	0.224
SELR, 2 Digesters	lb COD/lb VSinv-day	0.239	0.295	0.302	0.246	0.303	0.310	0.253	0.312	0.319	0.260	0.320	0.327	0.267	0.329	0.336
SELR, 1 Digester	lb COD/lb VSinv-day	0.478	0.590	0.603	0.492	0.607	0.620	0.506	0.624	0.637	0.520	0.641	0.655	0.534	0.658	0.672
Post-Digestion Solids Flow																
Total Hydraulic Flow	gpd	85,871	103,366	105,688	90,001	108,342	110,750	94,132	113,318	115,812	98,262	118,294	120,873	102,392	123,270	125,935
Post Digestion Total Solids	lb TS/day	18,690	22,593	22,984	19,684	23,790	24,202	20,677	24,987	25,419	21,671	26,184	26,637	22,664	27,381	27,854
Post Digestion Total Solids	ton TS/day	9.3	11.3	11.5	9.8	11.9	12.1	10.3	12.5	12.7	10.8	13.1	13.3	11.3	13.7	13.9
Post Digestion Solids Concentration, Combined	% TS	2.61%	2.62%	2.61%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.7%	2.6%	2.7%	2.7%	2.7%
Volatile Solids After Digestion	lb VS/day	12,168	14,699	14,953	12,820	15,485	15,753	13,473	16,271	16,553	14,125	17,057	17,352	14,778	17,843	18,152
VS/TS Ratio, Combined	% VS	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Percent Solids Increase from Baseline	lb TS/day	1,339	5,242	5,632	2,332	6,438	6,850	3,326	7,635	8,067	4,319	8,832	9,285	5,313	10,029	10,503

		Mesophilic Digestion (MAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
Dewatering																
Polymer Dosage	lb active/DT	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Neat Polymer Active Content	lb active/lb neat	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Polymer Delivery Rate, FW	lb neat/day	168	203	207	177	214	218	186	225	229	195	236	240	204	246	251
Dewatered Cake Solids Content	%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%
Cake Solids	ton TS/day	9.35	11.30	11.49	9.84	11.90	12.10	10.34	12.49	12.71	10.84	13.09	13.32	11.33	13.69	13.93
Cake Solids	ton TS/yr	3,411	4,123	4,195	3,592	4,342	4,417	3,774	4,560	4,639	3,955	4,779	4,861	4,136	4,997	5,083
Cake Solids	wet ton/day	75	90	92	79	95	97	83	100	102	87	105	107	91	110	111
Cake Solids	wet ton/yr	27,288	32,986	33,557	28,738	34,734	35,334	30,189	36,481	37,112	31,639	38,229	38,890	33,090	39,976	40,667
Dewatered Cake Density	wet lb/cf	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cake Storage Bays - Existing	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Cake Storage Bays - New	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Cake Storage Volume per Bay	cy	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367
Cake Storage Volume Available	cy	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700
Storage Time Provided	days	70	58	57	66	55	54	63	52	51	60	50	49	57	47	47
Digester Gas Management																
Average Plant Power Demand	kWe	700	692	692	738	782	782	777	875	875	816	808	808	914	905	905
Average Plant Power Demand	kWh/month	510,661	505,279	505,279	539,057	570,678	570,678	567,454	638,625	638,625	595,850	589,569	589,569	666,974	660,864	660,864
Solar Power Production	kWe	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
CHP Power Demand	kWe	649	642	642	688	731	731	727	824	824	766	757	757	863	855	855
CHP Power Demand	kWh/month	473,889	468,507	468,507	502,285	533,906	533,906	530,682	601,853	601,853	559,078	552,797	552,797	630,202	624,092	624,092
Specific Digester Gas Production, WW Solids	scf/lb VS destroyed	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Digester Gas Methane Content, WW Solids	% CH4 by volume	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
Digester Gas Production, WW Solids	scf/day DG	243,060	292,823	297,878	256,576	309,106	314,442	270,092	325,389	331,006	283,608	341,672	347,570	297,124	357,955	364,133
Methane Production, WW Solids	scf/day CH4	145,836	175,694	178,727	153,946	185,464	188,665	162,055	195,234	198,603	170,165	205,003	208,542	178,274	214,773	218,480
Specific Digester Gas Production, FOG	scf/lb VSR	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Digester Gas Methane Content, FOG	% CH4 by volume	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Digester Gas Production, FOG	scf/day DG	123,635	160,402	163,292	123,635	160,402	163,292	123,635	160,402	163,292	123,635	160,402	163,292	123,635	160,402	163,292
Methane Production, FOG	scf/day CH4	80,363	104,261	106,140	80,363	104,261	106,140	80,363	104,261	106,140	80,363	104,261	106,140	80,363	104,261	106,140
Digester Gas Production, WW Solids + FOG	scf/day DG	366,696	453,225	461,169	380,212	469,508	477,733	393,727	485,791	494,297	407,243	502,074	510,861	420,759	518,357	527,425
Digester Gas Production, WW Solids + FOG	scfm DG	255	315	320	264	326	332	273	337	343	283	349	355	292	360	366
Digester Gas Methane Production, WW Solids + FOG	scf/day CH4	226,199	279,955	284,866	234,309	289,725	294,804	242,418	299,495	304,743	250,528	309,264	314,681	258,637	319,034	324,620
Methane Content of Digester Gas, WW Solids + FOG	v/v	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	61%	62%	62%
Methane Yield, FW	scf CH4/lb FW TS digested	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Digester Gas Methane Content, FW	v/v	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Methane Production, FW	scf/day CH4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Digester Gas Production, FW	scf/day DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Methane Production	scf/day CH4	226,199	279,955	284,866	234,309	289,725	294,804	242,418	299,495	304,743	250,528	309,264	314,681	258,637	319,034	324,620
Total Digester Gas Production	scf/day DG	366,696	453,225	461,169	380,212	469,508	477,733	393,727	485,791	494,297	407,243	502,074	510,861	420,759	518,357	527,425
Total Digester Gas Production	scfm DG	255	315	320	264	326	332	273	337	343	283	349	355	292	360	366
Energy Content Methane - HHV	BTU/scf HHV	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011
Energy Content Methane - LHV	BTU/scf LHV	910	910	910	910	910	910	910	910	910	910	910	910	910	910	910
Net Digester Gas Methane Content	%CH4 by volume	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	61%	62%	62%
Net Digester Gas Energy Content	BTU/scf LHV	561	562	562	561	562	562	560	561	561	560	561	561	559	560	560
Wobbe Index	BTU/scf HHV	665	667	667	664	666	666	663	665	665	662	664	664	661	663	663
Gas Conditioning System Capacity (existing)	scfm	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Engine 1 Capacity (existing)	scfm	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Engine 2 Capacity (existing)	scfm	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
WGB Capacity (existing)	scfm	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150
Total Digester Gas Production	scfm	255	315	320	264	326	332	273	337	343	283	349	355	292	360	366
Digester Gas Production, WW Solids	scfm	169	203	207	178	215	218	188	226	230	197	237	241	206	249	253
Digester Gas Production, FOG	scfm	86	111	113	86	111	113	86	111	113	86	111	113	86	111	113
Digester Gas Production, FW	scfm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Digester Gas Energy, WW Solids	MMBTUf/day LHV	133	160	163	140	169	172	147	178	181	155	187	190	162	195	199
Digester Gas Energy, FOG	MMBTUf/day LHV	73	95	97	73	95	97	73	95	97	73	95	97	73	95	97
Digester Gas Energy, FW	MMBTUf/day LHV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Mesophilic Digestion (MAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
Total Digester Gas Energy	MMBTUf/day LHV	206	255	259	213	264	268	221	273	277	228	281	286	235	290	295
Digester Gas Energy, WW Solids	MMBTUf/day HHV	147	178	181	156	188	191	164	197	201	172	207	211	180	217	221
Digester Gas Energy, FOG	MMBTUf/day HHV	81	105	107	81	105	107	81	105	107	81	105	107	81	105	107
Digester Gas Energy, FW	MMBTUf/day HHV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Digester Gas Energy	MMBTUf/day HHV	229	283	288	237	293	298	245	303	308	253	313	318	261	323	328
Digester Gas Energy, WW Solids	kWf LHV	1,621	1,952	1,986	1,711	2,061	2,097	1,801	2,170	2,207	1,891	2,278	2,317	1,981	2,387	2,428
Digester Gas Energy, FOG	kWf LHV	893	1,159	1,180	893	1,159	1,180	893	1,159	1,180	893	1,159	1,180	893	1,159	1,180
Digester Gas Energy, FW	kWf LHV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Digester Gas Energy	kWf LHV	2,514	3,111	3,166	2,604	3,220	3,276	2,694	3,328	3,387	2,784	3,437	3,497	2,874	3,545	3,607
Total Available Elec Energy from CHP (max)	kWe LHV	792	980	997	820	1,014	1,032	849	1,048	1,067	877	1,083	1,102	905	1,117	1,136
Heat and Power Production																
Digester Heat Loss Factor	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Heat Demand for WW Solids	MMBTUth/day	29	35	36	31	37	38	33	39	40	34	41	42	36	43	44
Heat Demand for FOG	MMBTUth/day	5	5	6	5	5	6	5	5	6	5	5	6	5	5	6
Heat Demand for FW	MMBTUth/day	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Heat Demand	MMBTUth/day	34	41	42	36	43	44	37	45	46	39	47	48	40	49	50
Total Heat Demand	kWth	414	498	509	434	522	534	453	546	558	473	570	582	493	594	607
CHP																
CHP Electrical Efficiency	%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
CHP Heat Efficiency	%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
CHP Maximum Inlet Capacity - Existing	kWfuel/Engine LHV	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255
CHP Maximum Power Output - Existing	kWe/Engine	521	521	521	521	521	521	521	521	521	521	521	521	521	521	521
Equivalent Households per Engine	households/engine	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417
CHP Digester Gas Demand	kWf LHV	1,564	1,546	1,546	1,658	1,762	1,762	1,752	1,987	1,987	1,845	1,825	1,825	2,080	2,060	2,060
CHP Total Digester Gas Demand	MMBTUfuel/hr LHV	5.3	5.3	5.3	5.7	6.0	6.0	6.0	6.8	6.8	6.3	6.2	6.2	7.1	7.0	7.0
CHP Total Digester Gas Demand	scfm	158	156	156	168	178	178	178	201	201	187	185	185	211	209	209
CHP Natural Gas Demand	MMBTUng/hr LHV	0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP Power Production	kWelec	649	642	642	688	731	731	727	824	824	766	757	757	863	855	855
CHP Power Production	kWh/yr	5,686,671	5,622,082	5,622,082	6,027,425	6,406,874	6,406,874	6,368,178	7,222,242	7,222,242	6,708,932	6,633,569	6,633,569	7,562,424	7,489,101	7,489,101
Average Household Power Demand	kWe/household	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Equivalent Number of Households Powered	-	519	513	513	550	585	585	582	660	660	613	606	606	691	684	684
CHP Turndown	%	19%	20%	20%	14%	9%	9%	9%	-3%	-3%	4%	5%	5%	-8%	-7%	-7%
Plant Electrical Demand Provided by CHP	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
CHP Heat Production	MMBTUth/hr	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.5	1.5	1.4	1.4	1.4	1.6	1.6	1.6
CHP Heat Production	MMBTUth/day	28	28	28	30	32	32	32	36	36	33	33	33	38	37	37
CHP Heat Additional	MMBTUth/day	-6	-13	-14	-5	-11	-12	-5	-9	-10	-5	-14	-15	-3	-11	-12
CHP Heat Production	kWth	346	342	342	366	389	389	387	439	439	408	403	403	460	455	455
CHP Heat Additional or Lost	kWth	-68	-156	-167	-67	-132	-144	-66	-107	-119	-66	-167	-179	-34	-139	-151
BOILER																
Boiler Efficiency	%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Boiler Heat Production	MMBTUth/day	6	13	14	5	11	12	5	9	10	5	14	15	3	11	12
Boiler Fuel Demand	MMBTUf/hr LHV	0.3	0.7	0.7	0.3	0.6	0.6	0.3	0.5	0.5	0.3	0.7	0.8	0.1	0.6	0.6
Boiler Fuel Demand	kWfuel	84.9	195.2	209.1	83.9	165.5	180.0	82.9	133.5	148.5	81.9	208.2	223.7	41.9	173.2	189.2
Boiler Fuel Demand	scfm	8.6	19.7	21.1	8.5	16.7	18.2	8.4	13.5	15.0	8.3	21.0	22.6	4.2	17.5	19.1
Digester Gas Available for Drying	MMBTUf/hr LHV	2.9	4.7	4.8	2.9	4.4	4.6	2.9	4.1	4.3	2.9	4.8	4.9	2.6	4.5	4.6
Digester Gas Available for Drying	scfm	87.6	138.5	142.6	87.4	130.8	135.1	87.2	122.4	126.8	87.0	142.4	146.9	76.5	133.2	137.9
Total Heat Production	MMBTUth/day	33.9	40.8	41.7	35.5	42.7	43.7	37.1	44.7	45.7	38.8	46.7	47.7	40.4	48.6	49.7
Extra Heat Needed	MMBTUth/day	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	0.0	0.0
Hauling																
Truck Size	wet tons/load	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Weekly Truckloads w/o Drying	loads/week	17.4	21.1	21.5	18.4	22.2	22.6	19.3	23.3	23.7	20.2	24.4	24.9	21.2	25.6	26.0
Hauling Distance for Dewatered Cake	mi/round trip	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
Specific Cost of Highway Hauling	\$/mi-ton	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Cost of Highway Hauling	\$/yr	914,361	N/A	N/A	962,965	N/A	N/A	1,011,569	N/A	N/A	1,060,172	N/A	N/A	1,108,776	N/A	N/A
Truck Mileage	mi/gal	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Diesel Used	gal/yr	37,535	N/A	N/A	39,531	N/A	N/A	41,526	N/A	N/A	43,521	N/A	N/A	45,516	N/A	N/A
CO2 emission factor, diesel	lb CO2e/gal	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
CO2e emitted from hauling	ton CO2e/yr	417	N/A	N/A	439	N/A	N/A	461	N/A	N/A	483	N/A	N/A	505	N/A	N/A

		Temperature-Phased Anaerobic Digestion (TPAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
Feed to Digesters, WW Solids + Current FOG																
WW Solids Load	lb TS/day	34,071	41,046	41,755	35,965	43,329	44,076	37,860	45,611	46,398	39,754	47,893	48,720	41,649	50,176	51,042
WW Solids Load	lb TS/day rounded	34,100	41,000	41,800	36,000	43,300	44,100	37,900	45,600	46,400	39,800	47,900	48,700	41,600	50,200	51,000
WW Solids VS/TS Ratio	%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%
WW Solids Volatile Loading	lb VS/day	27,938	33,658	34,239	29,492	35,529	36,143	31,045	37,401	38,047	32,599	39,273	39,951	34,152	41,144	41,854
WW Solids Volatile Loading	lb VS/day rounded	27900	33700	34200	29500	35500	36100	31000	37400	38000	32600	39300	40000	34200	41100	41900
Digester Feed WW Solids Concentration	%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
WW Solids Flow to Digesters	gpd	74,277	89,484	91,028	78,407	94,460	96,090	82,537	99,435	101,152	86,668	104,411	106,214	90,798	109,387	111,275
WW Solids Flow to Digesters	gpd rounded	74,300	89,500	91,000	78,400	94,500	96,100	82,500	99,400	101,200	86,700	104,400	106,200	90,800	109,400	111,300
WW Solids Flow to Digesters	gpm	52	62	63	54	66	67	57	69	70	60	73	74	63	76	77
FOG Solids Volatile Loading	lb VS/day	8,676	11,256	11,459	8,676	11,256	11,459	8,676	11,256	11,459	8,676	11,256	11,459	8,676	11,256	11,459
FOG Solids Flow to Digesters	gpd	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660
FOG Solids Flow to Digesters	gpm	8.1	9.6	10.2	8.1	9.6	10.2	8.1	9.6	10.2	8.1	9.6	10.2	8.1	9.6	10.2
FOG Solids VS Concentration	% VS	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
FOG Solids TS Concentration	% TS	11%	12%	12%	11%	12%	12%	11%	12%	12%	11%	12%	12%	11%	12%	12%
Total WW Solids & current FOG VS Loading	lb VS/day	36,614	44,914	45,698	38,168	46,786	47,602	39,721	48,657	49,506	41,275	50,529	51,410	42,828	52,401	53,313
Total WW Solids & current FOG TS Loading	lb TS/day	43,137	52,808	53,729	45,031	55,091	56,050	46,926	57,373	58,372	48,820	59,656	60,694	50,715	61,938	63,016
Total WW Solids & current FOG VS Flow	gpd	85,871	103,366	105,688	90,001	108,342	110,750	94,132	113,318	115,812	98,262	118,294	120,873	102,392	123,270	125,935
Total WW Solids & current FOG VS Flow	gpm	60	72	73	63	75	77	65	79	80	68	82	84	71	86	87
Anaerobic Digestion																
Digester 1 Volume (existing)	MG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Digester 2 Volume (existing)	MG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Digester 3 Volume (new)	MG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
WW Solids VSR	%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
FOG VSR	%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
WW Solids Volatile Solids Destroyed	lb VSR/day	16,763	20,195	20,543	17,695	21,318	21,686	18,627	22,441	22,828	19,559	23,564	23,970	20,491	24,687	25,113
Current FOG Volatile Solids Destroyed	lb VSR/day	8,242	10,693	10,886	8,242	10,693	10,886	8,242	10,693	10,886	8,242	10,693	10,886	8,242	10,693	10,886
WW+current FOG Volatile Solids Destroyed	lb VSR/day	25,005	30,888	31,429	25,937	32,011	32,572	26,869	33,134	33,714	27,802	34,257	34,856	28,734	35,380	35,999
WW+current FOG Volatile Solids Destruction	%	68%	69%	69%	68%	68%	68%	68%	68%	68%	67%	68%	68%	67%	68%	68%
WW + current FOG Volatile Solids After Digestion	lb VS/day	11,609	14,026	14,268	12,230	14,775	15,030	12,852	15,523	15,792	13,473	16,272	16,553	14,095	17,021	17,315
WW + current FOG Total Solids After Digestion	lb TS/day	18,132	21,920	22,299	19,094	23,080	23,479	20,056	24,239	24,658	21,019	25,398	25,838	21,981	26,558	27,017
SOLIDS CAPACITY CHECK																
Max VSLR	lb VS/day-cf	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32
VSLR (WW+current FOG), 3 Digesters	lb VS/day-cf	0.091	0.112	0.114	0.095	0.117	0.119	0.099	0.121	0.123	0.103	0.126	0.128	0.107	0.131	0.133
VSLR (WW+current FOG), 2 Digesters	lb VS/day-cf	0.104	0.126	0.128	0.110	0.133	0.135	0.116	0.140	0.142	0.122	0.147	0.149	0.128	0.154	0.157
VSLR (WW+current FOG), 1 Digester	lb VS/day-cf	0.209	0.252	0.256	0.221	0.266	0.270	0.232	0.280	0.285	0.244	0.294	0.299	0.255	0.308	0.313
Max Solids Loading, 3 Digesters	lb VS/day	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342
Max Solids Loading, 2 Digesters	lb VS/day	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561
Max Solids Loading, 1 Digester	lb VS/day	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781
HYDRAULIC CAPACITY CHECK																
Minimum SRT	days	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
SRT (WW+current FOG), 3 Digesters	days	34.9	29.0	28.4	33.3	27.7	27.1	31.9	26.5	25.9	30.5	25.4	24.8	29.3	24.3	23.8
SRT (WW+current FOG), 2 Digesters	days	23.3	19.3	18.9	22.2	18.5	18.1	21.2	17.6	17.3	20.4	16.9	16.5	19.5	16.2	15.9
SRT (WW+current FOG), 1 Digester	days	11.6	9.7	9.5	11.1	9.2	9.0	10.6	8.8	8.6	10.2	8.5	8.3	9.8	8.1	7.9
Max Hydraulic Flow to Digesters, 3 Digesters	gpm	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
Max Hydraulic Flow to Digesters, 2 Digesters	gpm	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
Max Hydraulic Flow to Digesters, 1 Digester	gpm	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
SELR CHECK																
Max SELR	lb COD/lb VS-day	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
COD - WW Solids	lb COD/lb VS	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
COD - FOG	lb COD/lb VS	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
COD Added - WW Solids	lb COD/day	41,907	50,487	51,358	44,237	53,294	54,214	46,568	56,102	57,070	48,898	58,909	59,926	51,228	61,716	62,782
COD Added - FOG	lb COD/day	25,161	32,643	33,231	25,161	32,643	33,231	25,161	32,643	33,231	25,161	32,643	33,231	25,161	32,643	33,231
Digester VS Inventory, WW+FOG, 3 Digesters	lb VSinv Total	405,573	407,076	405,017	407,675	409,110	407,135	409,592	410,965	409,068	411,347	412,664	410,839	412,961	414,226	412,468
Digester VS Inventory, WW+FOG, 2 Digesters	lb VSinv Total	270,382	271,384	270,011	271,783	272,740	271,423	273,061	273,977	272,712	274,231	275,109	273,893	275,308	276,151	274,979
Digester VS Inventory, WW+FOG, 1 Digester	lb VSinv Total	135,191	135,692	135,006	135,892	136,370	135,712	136,531	136,988	136,356	137,116	137,555	136,946	137,654	138,075	137,489
SELR, 3 Digesters	lb COD/lb VSinv-day	0.165	0.204	0.209	0.170	0.210	0.215	0.175	0.216	0.221	0.180	0.222	0.227	0.185	0.228	0.233
SELR, 2 Digesters	lb COD/lb VSinv-day	0.248	0.306	0.313	0.255	0.315	0.322	0.263	0.324	0.331	0.270	0.333	0.340	0.277	0.342	0.349
SELR, 1 Digester	lb COD/lb VSinv-day	0.496	0.613	0.627	0.511	0.630	0.644	0.525	0.648	0.662	0.540	0.666	0.680	0.555	0.683	0.698

		Temperature-Phased Anaerobic Digestion (TPAD) w/ Additional Feedstock														
	Units	2027			2032			2037			2042			2047		
		Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
EXTRA FEEDSTOCK DIGESTION																
Mass of Additional FOG Added to Digesters	wet tons/yr	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072
Solids Content Hauled to WWTP - Addt'l FOG	% TS	11%	12%	12%	11%	12%	12%	11%	12%	12%	11%	12%	12%	11%	12%	12%
FOG VS Content	% VS	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
Addt'l FOG TS Added to Digestion	lb TS/day	10,449	11,322	10,915	10,449	11,322	10,915	10,449	11,322	10,915	10,449	11,322	10,915	10,449	11,322	10,915
Addt'l FOG VS Added to Digestion	lb VS/day	10,000	10,836	10,446	10,000	10,836	10,446	10,000	10,836	10,446	10,000	10,836	10,446	10,000	10,836	10,446
Volume of Addt'l FOG Added to Digestion	gpd	13,364	13,364	13,364	13,364	13,364	13,364	13,364	13,364	13,364	13,364	13,364	13,364	13,364	13,364	13,364
VSR - FOG	% VSR	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Addt'l FOG Volatile Solids Reduced	lb VSR/day	9,500	10,294	9,924	9,500	10,294	9,924	9,500	10,294	9,924	9,500	10,294	9,924	9,500	10,294	9,924
Mass of Food Waste Added to Digesters	wet tons/yr	0	0	0	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Solids Content Hauled to WWTP - FW	% TS	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Food Waste VS Content	% VS	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%
Food Waste TS Added to Digestion	lb TS/day	0	0	0	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014
Food Waste VS Added to Digestion	lb VS/day	0	0	0	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022
Mass of Food Waste Hauled to WWTP	wet ton/day	0	0	0	77	77	77	77	77	77	77	77	77	77	77	77
Volume of Food Waste Hauled to WWTP	gal/day	0	0	0	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396
Volume of Food Waste Hauled to WWTP	gal/yr	0	0	0	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628
Solids Content into Digester - FW	% TS	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Volume into Digester - FW	gpd	0	0	0	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995
VSR - FW	%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
FW Volatile Solids Destroyed	lb VSR/day	0	0	0	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019
Total Volume of FW and FOG added to Digesters	gpd	24,958	27,246	28,023	47,953	50,241	51,019	47,953	50,241	51,019	47,953	50,241	51,019	47,953	50,241	51,019
Total Volume Added to Digesters, WW Solids + FOG + FW	gpd	99,235	116,730	119,052	126,360	144,701	147,109	130,490	149,677	152,170	134,621	154,653	157,232	138,751	159,629	162,294
Volatile Solids After Digestion	lb VS/day	12,109	14,568	14,791	15,734	18,320	18,556	16,355	19,068	19,317	16,977	19,817	20,079	17,598	20,566	20,840
Total Solids After Digestion	lb TS/day	19,081	22,949	23,291	26,038	30,103	30,465	27,001	31,263	31,645	27,963	32,422	32,824	28,926	33,582	34,004
Addl FOG/FW After Digestion	lb TS/day															
SOLIDS CAPACITY CHECK w/FW																
Max VSLR	lb VS/day-cf	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32
VSLR, 3 Digesters	lb VS/day-cf	0.116	0.139	0.140	0.170	0.194	0.195	0.174	0.198	0.199	0.178	0.203	0.204	0.182	0.208	0.209
VSLR, 2 Digesters	lb VS/day-cf	0.174	0.209	0.210	0.255	0.290	0.292	0.261	0.297	0.299	0.267	0.304	0.306	0.272	0.311	0.313
VSLR, 1 Digester	lb VS/day-cf	0.349	0.417	0.420	0.510	0.581	0.584	0.522	0.595	0.598	0.533	0.609	0.612	0.545	0.623	0.627
Max Solids Loading, 3 Digesters	lb VS/day	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342
Max Solids Loading, 2 Digesters	lb VS/day	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561
Max Solids Loading, 1 Digester	lb VS/day	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781
HYDRAULIC CAPACITY CHECK w/FW																
Minimum SRT	days	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
SRT, 3 Digesters	days	30.2	25.7	25.2	23.7	20.7	20.4	23.0	20.0	19.7	22.3	19.4	19.1	21.6	18.8	18.5
SRT, 2 Digesters	days	20.2	17.1	16.8	15.8	13.8	13.6	15.3	13.4	13.1	14.9	12.9	12.7	14.4	12.5	12.3
SRT, 1 Digester	days	10.1	8.6	8.4	7.9	6.9	6.8	7.7	6.7	6.6	7.4	6.5	6.4	7.2	6.3	6.2
Max Hydraulic Flow to Digesters, 3 Digesters	gpm	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
Max Hydraulic Flow to Digesters, 2 Digesters	gpm	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
Max Hydraulic Flow to Digesters, 1 Digester	gpm	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
SELR CHECK																
Max SELR (Target of 0.3, max of 0.5)	lb COD/lb VS-day	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
COD - WW Solids	lb COD/lb VS	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
COD - FOG	lb COD/lb VS	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
COD - FW	lb COD/lb VS	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76
COD Added - WW Solids	lb COD/day	42,502	51,203	52,087	44,865	54,051	54,983	47,228	56,898	57,880	49,592	59,745	60,776	51,955	62,592	63,673
COD Added - FOG	lb COD/day	54161	64066	63524	54161	64066	63524	54161	64066	63524	54161	64066	63524	54161	64066	63524
COD Added - FW	lb COD/day	0	0	0	35288	35288	35288	35288	35288	35288	35288	35288	35288	35288	35288	35288
Percent of Total COD Added as FOG	%	56%	56%	55%	40%	42%	41%	40%	41%	41%	39%	40%	40%	38%	40%	39%
Percent of WW Solids COD Added as FOG	%	127%	125%	122%	121%	119%	116%	115%	113%	110%	109%	107%	105%	104%	102%	100%
Digester VS Inventory, WW+FOG+FW, 3 Digesters	lb VSinv Total	350,956	360,472	359,554	361,673	368,578	367,755	364,512	371,330	370,536	367,177	373,905	373,138	369,683	376,320	375,578
Digester VS Inventory, WW+FOG+FW, 2 Digesters	lb VSinv Total	233,971	240,315	239,702	241,116	245,719	245,170	243,008	247,554	247,024	244,784	249,270	248,759	246,455	250,880	250,385
Digester VS Inventory, WW+FOG+FW, 1 Digester	lb VSinv Total	116,985	120,157	119,851	120,558	122,859	122,585	121,504	123,777	123,512	122					

		Temperature-Phased Anaerobic Digestion (TPAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
Dewatering																
Polymer Dosage	lb active/DT	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Neat Polymer Active Content	lb active/lb neat	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Polymer Delivery Rate, FW	lb neat/day	172	207	210	234	271	274	243	281	285	252	292	295	260	302	306
Dewatered Cake Solids Content	%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
Cake Solids	ton TS/day	9.54	11.47	11.65	13.02	15.05	15.23	13.50	15.63	15.82	13.98	16.21	16.41	14.46	16.79	17.00
Cake Solids	ton TS/yr	3,482	4,188	4,251	4,752	5,494	5,560	4,928	5,705	5,775	5,103	5,917	5,990	5,279	6,129	6,206
Cake Solids	wet ton/day	62	74	75	84	97	98	87	101	102	90	105	106	93	108	110
Cake Solids	wet ton/yr	22,466	27,020	27,423	30,658	35,444	35,871	31,791	36,809	37,259	32,925	38,175	38,648	34,058	39,540	40,037
Dewatered Cake Density	wet lb/cf	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cake Storage Bays - Existing	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Cake Storage Bays - New	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Cake Storage Volume per Bay	cy	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367
Cake Storage Volume Available	cy	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700
Storage Time Provided	days	84	70	69	62	54	53	60	52	51	58	50	49	56	48	47
Digester Gas Management																
Average Plant Power Demand	kWe	700	692	692	738	782	782	777	875	875	816	808	808	914	905	905
Average Plant Power Demand	kWh/month	510,661	505,279	505,279	539,057	570,678	570,678	567,454	638,625	638,625	595,850	589,569	589,569	666,974	660,864	660,864
Solar Power Production	kWe	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
CHP Power Demand	kWe	649	642	642	688	731	731	727	824	824	766	757	757	863	855	855
CHP Power Demand	kWh/month	473,889	468,507	468,507	502,285	533,906	533,906	530,682	601,853	601,853	559,078	552,797	552,797	630,202	624,092	624,092
Specific Digester Gas Production, WW Solids	scf/lb VS destroyed	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Digester Gas Methane Content, WW Solids	% CH4 by volume	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
Digester Gas Production, WW Solids	scf/day DG	251,442	302,921	308,149	265,424	319,765	325,284	279,406	336,610	342,420	293,387	353,454	359,555	307,369	370,298	376,690
Methane Production, WW Solids	scf/day CH4	150,865	181,752	184,890	159,254	191,859	195,171	167,643	201,966	205,452	176,032	212,072	215,733	184,422	222,179	226,014
Specific Digester Gas Production, FOG	scf/lb VSR	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Digester Gas Methane Content, FOG	% CH4 by volume	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Digester Gas Production, FOG	scf/day DG	266,137	314,808	312,146	266,137	314,808	312,146	266,137	314,808	312,146	266,137	314,808	312,146	266,137	314,808	312,146
Methane Production, FOG	scf/day CH4	172,989	204,625	202,895	172,989	204,625	202,895	172,989	204,625	202,895	172,989	204,625	202,895	172,989	204,625	202,895
Digester Gas Production, WW Solids + FOG	scf/day DG	517,579	617,729	620,295	531,561	634,573	637,430	545,543	651,417	654,565	559,524	668,262	671,700	573,506	685,106	688,835
Digester Gas Production, WW Solids + FOG	scfm DG	359	429	431	369	441	443	379	452	455	389	464	466	398	476	478
Digester Gas Methane Production, WW Solids + FOG	scf/day CH4	323,854	386,378	387,784	332,243	396,484	398,065	340,632	406,591	408,346	349,021	416,697	418,627	357,411	426,804	428,909
Methane Content of Digester Gas, WW Solids + FOG	v/v	63%	63%	63%	63%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%
Methane Yield, FW	scf CH4/lb FW TS digested	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Digester Gas Methane Content, FW	v/v	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Methane Production, FW	scf/day CH4	0	0	0	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082
Digester Gas Production, FW	scf/day DG	0	0	0	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434
Total Methane Production	scf/day CH4	323,854	386,378	387,784	470,325	534,566	536,147	478,715	544,673	546,429	487,104	554,780	556,710	495,493	564,886	566,991
Total Digester Gas Production	scf/day DG	517,579	617,729	620,295	743,995	847,007	849,864	757,977	863,852	866,999	771,958	880,696	884,134	785,940	897,540	901,270
Total Digester Gas Production	scfm DG	359	429	431	517	588	590	526	600	602	536	612	614	546	623	626
Energy Content Methane - HHV	BTU/scf HHV	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011
Energy Content Methane - LHV	BTU/scf LHV	910	910	910	910	910	910	910	910	910	910	910	910	910	910	910
Net Digester Gas Methane Content	%CH4 by volume	63%	63%	63%	63%	63%	63%	63%	63%	63%	63%	63%	63%	63%	63%	63%
Net Digester Gas Energy Content	BTU/scf LHV	569	569	569	575	574	574	575	574	574	574	573	573	574	573	572
Wobbe Index	BTU/scf HHV	681	681	680	693	691	691	692	690	690	691	689	689	690	688	688
Gas Conditioning System Capacity (existing)	scfm	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Engine 1 Capacity (existing)	scfm	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Engine 2 Capacity (existing)	scfm	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
WGB Capacity (existing)	scfm	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150
Total Digester Gas Production	scfm	359	429	431	517	588	590	526	600	602	536	612	614	546	623	626
Digester Gas Production, WW Solids	scfm	175	210	214	184	222	226	194	234	238	204	245	250	213	257	262
Digester Gas Production, FOG	scfm	185	219	217	185	219	217	185	219	217	185	219	217	185	219	217
Digester Gas Production, FW	scfm	0	0	0	148	148	148	148	148	148	148	148	148	148	148	148
Digester Gas Energy, WW Solids	MMBTUf/day LHV	137	165	168	145	175	178	153	184	187	160	193	196	168	202	206
Digester Gas Energy, FOG	MMBTUf/day LHV	157	186	185	157	186	185	157	186	185	157	186	185	157	186	185
Digester Gas Energy, FW	MMBTUf/day LHV	0	0	0	126	126	126	126	126	126	126	126	126	126	126	126

		Temperature-Phased Anaerobic Digestion (TPAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
Total Digester Gas Energy	MMBTUf/day LHV	295	352	353	428	486	488	436	496	497	443	505	507	451	514	516
Digester Gas Energy, WW Solids	MMBTUf/day HHV	153	184	187	161	194	197	169	204	208	178	214	218	186	225	229
Digester Gas Energy, FOG	MMBTUf/day HHV	175	207	205	175	207	205	175	207	205	175	207	205	175	207	205
Digester Gas Energy, FW	MMBTUf/day HHV	0	0	0	140	140	140	140	140	140	140	140	140	140	140	140
Total Digester Gas Energy	MMBTUf/day HHV	327	391	392	475	540	542	484	551	552	492	561	563	501	571	573
Digester Gas Energy, WW Solids	kWf LHV	1,677	2,020	2,055	1,770	2,132	2,169	1,863	2,244	2,283	1,956	2,357	2,397	2,049	2,469	2,512
Digester Gas Energy, FOG	kWf LHV	1,922	2,274	2,255	1,922	2,274	2,255	1,922	2,274	2,255	1,922	2,274	2,255	1,922	2,274	2,255
Digester Gas Energy, FW	kWf LHV	0	0	0	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534
Total Digester Gas Energy	kWf LHV	3,599	4,294	4,309	5,227	5,940	5,958	5,320	6,053	6,072	5,413	6,165	6,187	5,506	6,277	6,301
Total Available Elec Energy from CHP (max)	kWe LHV	1,134	1,353	1,357	1,646	1,871	1,877	1,676	1,907	1,913	1,705	1,942	1,949	1,734	1,977	1,985
Heat and Power Production																
Digester Heat Loss Factor	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Heat Demand for WW Solids	MMBTUth/day	55	66	67	58	69	71	61	73	74	64	77	78	67	80	82
Heat Demand for FOG	MMBTUth/day	9	10	11	9	10	11	9	10	11	9	10	11	9	10	11
Heat Demand for FW	MMBTUth/day	0	0	0	17	17	17	17	17	17	17	17	17	17	17	17
Total Heat Demand	MMBTUth/day	63	76	78	83	96	98	86	100	102	89	104	106	92	107	109
Total Heat Demand	kWth	770	926	947	1013	1177	1199	1050	1222	1244	1087	1266	1289	1124	1311	1335
CHP																
CHP Electrical Efficiency	%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
CHP Heat Efficiency	%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
CHP Maximum Inlet Capacity - Existing	kWFuel/Engine LHV	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255
CHP Maximum Power Output - Existing	kWe/Engine	521	521	521	521	521	521	521	521	521	521	521	521	521	521	521
Equivalent Households per Engine	households/engine	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417
CHP Digester Gas Demand	kWf LHV	1,564	1,546	1,546	1,658	1,762	1,762	1,752	1,987	1,987	1,845	1,825	1,825	2,080	2,060	2,060
CHP Total Digester Gas Demand	MMBTUfuel/hr LHV	5.3	5.3	5.3	5.7	6.0	6.0	6.0	6.8	6.8	6.3	6.2	6.2	7.1	7.0	7.0
CHP Total Digester Gas Demand	scfm	156	155	155	164	175	175	173	197	197	183	181	181	206	205	205
CHP Natural Gas Demand	MMBTUng/hr LHV	0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP Power Production	kWelec	649	642	642	688	731	731	727	824	824	766	757	757	863	855	855
CHP Power Production	kWh/yr	5,686,671	5,622,082	5,622,082	6,027,425	6,406,874	6,406,874	6,368,178	7,222,242	7,222,242	6,708,932	6,633,569	6,633,569	7,562,424	7,489,101	7,489,101
Average Household Power Demand	kWe/household	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Equivalent Number of Households Powered	-	519	513	513	550	585	585	582	660	660	613	606	606	691	684	684
CHP Turndown	%	19%	20%	20%	14%	9%	9%	9%	-3%	-3%	4%	5%	5%	-8%	-7%	-7%
Plant Electrical Demand Provided by CHP	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
CHP Heat Production	MMBTUth/hr	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.5	1.5	1.4	1.4	1.4	1.6	1.6	1.6
CHP Heat Production	MMBTUth/day	28	28	28	30	32	32	32	36	36	33	33	33	38	37	37
CHP Heat Additional	MMBTUth/day	-35	-48	-50	-53	-64	-66	-54	-64	-66	-56	-71	-73	-54	-70	-72
CHP Heat Production	kWth	346	342	342	366	389	389	387	439	439	408	403	403	460	455	455
CHP Heat Additional or Lost	kWth	-424	-585	-605	-646	-788	-809	-663	-783	-805	-679	-863	-886	-664	-856	-880
BOILER																
Boiler Efficiency	%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Boiler Heat Production	MMBTUth/day	35	48	50	53	64	66	54	64	66	56	71	73	54	70	72
Boiler Fuel Demand	MMBTUf/hr LHV	1.8	2.5	2.6	2.8	3.4	3.5	2.8	3.3	3.4	2.9	3.7	3.8	2.8	3.6	3.8
Boiler Fuel Demand	kWFuel	529.7	730.6	756.6	807.7	984.3	1011.2	828.0	978.0	1006.0	848.4	1078.5	1107.4	829.8	1069.2	1099.1
Boiler Fuel Demand	scfm	52.7	72.6	75.2	80.3	97.8	100.5	82.3	97.2	100.0	84.3	107.2	110.1	82.5	106.3	109.3
Digester Gas Available for Drying	MMBTUf/hr LHV	5.1	6.9	6.8	9.4	10.9	10.9	9.3	10.5	10.5	9.3	11.1	11.1	8.9	10.7	10.7
Digester Gas Available for Drying	scfm	150.3	201.5	200.5	272.9	316.2	315.4	271.1	306.0	305.3	269.3	323.6	323.0	257.3	312.6	312.0
Total Heat Production	MMBTUth/day	63.0	75.9	77.6	82.9	96.4	98.2	86.0	100.0	101.9	89.0	103.7	105.6	92.0	107.3	109.3
Extra Heat Needed	MMBTUth/day	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	0.0	0.0
Hauling																
Truck Size	wet tons/load	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Weekly Truckloads w/o Drying	loads/week	14.4	17.3	17.5	19.6	22.7	22.9	20.3	23.5	23.8	21.0	24.4	24.7	21.8	25.3	25.6
Hauling Distance for Dewatered Cake	mi/round trip	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
Specific Cost of Highway Hauling	\$/mi-ton	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Cost of Highway Hauling	\$/yr	752,797	N/A	N/A	1,027,291	N/A	N/A	1,065,262	N/A	N/A	1,103,232	N/A	N/A	1,141,203	N/A	N/A
Truck Mileage	mi/gal	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Diesel Used	gal/yr	30,903	N/A	N/A	42,171	N/A	N/A	43,730	N/A	N/A	45,289	N/A	N/A	46,847	N/A	N/A
CO2 emission factor, diesel	lb CO2e/gal	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
CO2e emitted from hauling	ton CO2e/yr	343	N/A	N/A	468	N/A	N/A	485	N/A	N/A	503	N/A	N/A	520	N/A	N/A

		Thermophilic Digestion (TAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
Feed to Digesters, WW Solids + Current FOG		2027	2027	2027	2032	2032	2032	2037	2037	2037	2042	2042	2042	2047	2047	2047
WW Solids Load	lb TS/day	34,071	41,046	41,755	35,965	43,329	44,076	37,860	45,611	46,398	39,754	47,893	48,720	41,649	50,176	51,042
WW Solids Load	lb TS/day rounded	34,100	41,000	41,800	36,000	43,300	44,100	37,900	45,600	46,400	39,800	47,900	48,700	41,600	50,200	51,000
WW Solids VS/TS Ratio	%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%
WW Solids Volatile Loading	lb VS/day	27,938	33,658	34,239	29,492	35,529	36,143	31,045	37,401	38,047	32,599	39,273	39,951	34,152	41,144	41,854
WW Solids Volatile Loading	lb VS/day rounded	27900	33700	34200	29500	35500	36100	31000	37400	38000	32600	39300	40000	34200	41100	41900
Digester Feed WW Solids Concentration	%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
WW Solids Flow to Digesters	gpd	74,277	89,484	91,028	78,407	94,460	96,090	82,537	99,435	101,152	86,668	104,411	106,214	90,798	109,387	111,275
WW Solids Flow to Digesters	gpd rounded	74,300	89,500	91,000	78,400	94,500	96,100	82,500	99,400	101,200	86,700	104,400	106,200	90,800	109,400	111,300
WW Solids Flow to Digesters	gpm	52	62	63	54	66	67	57	69	70	60	73	74	63	76	77
FOG Solids Volatile Loading	lb VS/day	8,676	11,256	11,459	8,676	11,256	11,459	8,676	11,256	11,459	8,676	11,256	11,459	8,676	11,256	11,459
FOG Solids Flow to Digesters	gpd	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660	11,594	13,882	14,660
FOG Solids Flow to Digesters	gpm	8.1	9.6	10.2	8.1	9.6	10.2	8.1	9.6	10.2	8.1	9.6	10.2	8.1	9.6	10.2
FOG Solids VS Concentration	% VS	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
FOG Solids TS Concentration	% TS	11%	12%	12%	11%	12%	12%	11%	12%	12%	11%	12%	12%	11%	12%	12%
Total WW Solids & current FOG VS Loading	lb VS/day	36,614	44,914	45,698	38,168	46,786	47,602	39,721	48,657	49,506	41,275	50,529	51,410	42,828	52,401	53,313
Total WW Solids & current FOG TS Loading	lb TS/day	43,137	52,808	53,729	45,031	55,091	56,050	46,926	57,373	58,372	48,820	59,656	60,694	50,715	61,938	63,016
Total WW Solids & current FOG VS Flow	gpd	85,871	103,366	105,688	90,001	108,342	110,750	94,132	113,318	115,812	98,262	118,294	120,873	102,392	123,270	125,935
Total WW Solids & current FOG VS Flow	gpm	60	72	73	63	75	77	65	79	80	68	82	84	71	86	87
Anaerobic Digestion																
Digester 1 Volume (existing)	MG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Digester 2 Volume (existing)	MG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Digester 3 Volume (new)	MG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
WW Solids VSR	%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%
FOG VSR	%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
WW Solids Volatile Solids Destroyed	lb VSR/day	17,880	21,541	21,913	18,875	22,739	23,131	19,869	23,937	24,350	20,863	25,135	25,568	21,857	26,332	26,787
Current FOG Volatile Solids Destroyed	lb VSR/day	8,242	10,693	10,886	8,242	10,693	10,886	8,242	10,693	10,886	8,242	10,693	10,886	8,242	10,693	10,886
WW+current FOG Volatile Solids Destroyed	lb VSR/day	26,123	32,234	32,799	27,117	33,432	34,017	28,111	34,630	35,236	29,105	35,828	36,454	30,100	37,026	37,673
WW+current FOG Volatile Solids Destruction	%	71%	72%	72%	71%	71%	71%	71%	71%	71%	71%	71%	71%	70%	71%	71%
WW + current FOG Volatile Solids After Digestion	lb VS/day	10,491	12,680	12,899	11,051	13,353	13,584	11,610	14,027	14,270	12,169	14,701	14,955	12,729	15,375	15,641
WW + current FOG Total Solids After Digestion	lb TS/day	17,014	20,574	20,930	17,914	21,658	22,033	18,815	22,743	23,136	19,715	23,828	24,240	20,615	24,912	25,343
SOLIDS CAPACITY CHECK																
Max VSLR	lb VS/day-cf	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32
VSLR (WW+current FOG), 3 Digesters	lb VS/day-cf	0.091	0.112	0.114	0.095	0.117	0.119	0.099	0.121	0.123	0.103	0.126	0.128	0.107	0.131	0.133
VSLR (WW+current FOG), 2 Digesters	lb VS/day-cf	0.104	0.126	0.128	0.110	0.133	0.135	0.116	0.140	0.142	0.122	0.147	0.149	0.128	0.154	0.157
VSLR (WW+current FOG), 1 Digester	lb VS/day-cf	0.209	0.252	0.256	0.221	0.266	0.270	0.232	0.280	0.285	0.244	0.294	0.299	0.255	0.308	0.313
Max Solids Loading, 3 Digesters	lb VS/day	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342
Max Solids Loading, 2 Digesters	lb VS/day	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561
Max Solids Loading, 1 Digester	lb VS/day	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781
HYDRAULIC CAPACITY CHECK																
Minimum SRT	days	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
SRT (WW+current FOG), 3 Digesters	days	34.9	29.0	28.4	33.3	27.7	27.1	31.9	26.5	25.9	30.5	25.4	24.8	29.3	24.3	23.8
SRT (WW+current FOG), 2 Digesters	days	23.3	19.3	18.9	22.2	18.5	18.1	21.2	17.6	17.3	20.4	16.9	16.5	19.5	16.2	15.9
SRT (WW+current FOG), 1 Digester	days	11.6	9.7	9.5	11.1	9.2	9.0	10.6	8.8	8.6	10.2	8.5	8.3	9.8	8.1	7.9
Max Hydraulic Flow to Digesters, 3 Digesters	gpm	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
Max Hydraulic Flow to Digesters, 2 Digesters	gpm	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
Max Hydraulic Flow to Digesters, 1 Digester	gpm	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
SELR CHECK																
Max SELR	lb COD/lb VSinv-day	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
COD - WW Solids	lb COD/lb VS	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
COD - FOG	lb COD/lb VS	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
COD Added - WW Solids	lb COD/day	41,907	50,487	51,358	44,237	53,294	54,214	46,568	56,102	57,070	48,898	58,909	59,926	51,228	61,716	62,782
COD Added - FOG	lb COD/day	25,161	32,643	33,231	25,161	32,643	33,231	25,161	32,643	33,231	25,161	32,643	33,231	25,161	32,643	33,231
Digester VS Inventory, WW+FOG, 3 Digesters	lb VSinv Total	366,532	368,002	366,142	368,353	369,757	367,974	370,015	371,358	369,645	371,537	372,825	371,177	372,936	374,173	372,586
Digester VS Inventory, WW+FOG, 2 Digesters	lb VSinv Total	244,354	245,334	244,094	245,569	246,505	245,316	246,677	247,572	246,430	247,691	248,550	247,452	248,624	249,449	248,391
Digester VS Inventory, WW+FOG, 1 Digester	lb VSinv Total	122,177	122,667	122,047	122,784	123,252	122,658	123,338	123,786	123,215	123,846	124,275	123,726	124,312	124,724	124,195
SELR, 3 Digesters	lb COD/lb VSinv-day	0.183	0.226	0.231	0.188	0.232	0.238	0.194	0.239	0.244	0.199	0.246	0.251	0.205	0.252	0.258
SELR, 2 Digesters	lb COD/lb VSinv-day	0.274	0.339	0.347	0.283	0.349	0.356	0.291	0.358	0.366	0.299	0.368	0.376	0.307	0.378	0.387
SELR, 1 Digester	lb COD/lb VSinv-day	0.549	0.678	0.693	0.565	0.697	0.713	0.582	0.717	0.733	0.598	0.737	0.753	0.614	0.757	0.773

		Thermophilic Digestion (TAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
EXTRA FEEDSTOCK DIGESTION																
Mass of Additional FOG Added to Digesters	wet tons/yr	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072	17,072
Solids Content Hauled to WWTP - Addt'l FOG	% TS	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
FOG VS Content	% VS	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
Addt'l FOG TS Added to Digestion	lb TS/day	11,225	11,225	11,225	11,225	11,225	11,225	11,225	11,225	11,225	11,225	11,225	11,225	11,225	11,225	11,225
Addt'l FOG VS Added to Digestion	lb VS/day	10,743	10,743	10,743	10,743	10,743	10,743	10,743	10,743	10,743	10,743	10,743	10,743	10,743	10,743	10,743
Volume of Addt'l FOG Added to Digestion	gpd	14,356	13,249	13,743	14,356	13,249	13,743	14,356	13,249	13,743	14,356	13,249	13,743	14,356	13,249	13,743
VSR - FOG	% VSR	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Addt'l FOG Volatile Solids Reduced	lb VSR/day	10,206	10,206	10,206	10,206	10,206	10,206	10,206	10,206	10,206	10,206	10,206	10,206	10,206	10,206	10,206
Mass of Food Waste Added to Digesters	wet tons/yr	0	0	0	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Solids Content Hauled to WWTP - FW	% TS	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Food Waste VS Content	% VS	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%
Food Waste TS Added to Digestion	lb TS/day	0	0	0	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014	23,014
Food Waste VS Added to Digestion	lb VS/day	0	0	0	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022	20,022
Mass of Food Waste Hauled to WWTP	wet ton/day	0	0	0	77	77	77	77	77	77	77	77	77	77	77	77
Volume of Food Waste Hauled to WWTP	gal/day	0	0	0	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396	18,396
Volume of Food Waste Hauled to WWTP	gal/yr	0	0	0	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628	6,714,628
Solids Content into Digester - FW	% TS	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Volume into Digester - FW	gpd	0	0	0	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995	22,995
VSR - FW	%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
FW Volatile Solids Destroyed	lb VSR/day	0	0	0	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019
Total Volume of FW and FOG added to Digesters	gpd	25,950	27,132	28,403	48,946	50,127	51,398	48,946	50,127	51,398	48,946	50,127	51,398	48,946	50,127	51,398
Total Volume Added to Digesters, WW Solids + FOG + FW	gpd	100,227	116,615	119,431	127,353	144,587	147,488	131,483	149,562	152,550	135,613	154,538	157,612	139,743	159,514	162,674
Volatile Solids After Digestion	lb VS/day	11,029	13,217	13,436	14,591	16,894	17,125	15,150	17,568	17,810	15,710	18,241	18,496	16,269	18,915	19,181
Total Solids After Digestion	lb TS/day	18,034	21,594	21,949	24,929	28,673	29,048	25,830	29,758	30,151	26,730	30,842	31,255	27,630	31,927	32,358
Addl FOG/FW After Digestion	lb TS/day	1020	1020	1020	7015	7015	7015	7015	7015	7015	7015	7015	7015	7015	7015	7015
SOLIDS CAPACITY CHECK w/FW																
Max VSLR	lb VS/day-cf	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32	0.30	0.30	0.32
VSLR, 3 Digesters	lb VS/day-cf	0.118	0.139	0.141	0.172	0.193	0.195	0.176	0.198	0.200	0.180	0.203	0.205	0.183	0.207	0.210
VSLR, 2 Digesters	lb VS/day-cf	0.177	0.208	0.211	0.258	0.290	0.293	0.264	0.297	0.300	0.269	0.304	0.307	0.275	0.311	0.314
VSLR, 1 Digester	lb VS/day-cf	0.354	0.416	0.422	0.516	0.580	0.586	0.527	0.594	0.600	0.539	0.608	0.615	0.550	0.622	0.629
Max Solids Loading, 3 Digesters	lb VS/day	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342	120,321	120,321	128,342
Max Solids Loading, 2 Digesters	lb VS/day	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561	80,214	80,214	85,561
Max Solids Loading, 1 Digester	lb VS/day	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781	40,107	40,107	42,781
HYDRAULIC CAPACITY CHECK w/FW																
Minimum SRT	days	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
SRT, 3 Digesters	days	29.9	25.7	25.1	23.6	20.7	20.3	22.8	20.1	19.7	22.1	19.4	19.0	21.5	18.8	18.4
SRT, 2 Digesters	days	20.0	17.2	16.7	15.7	13.8	13.6	15.2	13.4	13.1	14.7	12.9	12.7	14.3	12.5	12.3
SRT, 1 Digester	days	10.0	8.6	8.4	7.9	6.9	6.8	7.6	6.7	6.6	7.4	6.5	6.3	7.2	6.3	6.1
Max Hydraulic Flow to Digesters, 3 Digesters	gpm	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
Max Hydraulic Flow to Digesters, 2 Digesters	gpm	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
Max Hydraulic Flow to Digesters, 1 Digester	gpm	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
SELR CHECK																
Max SELR (Target of 0.3, max of 0.5)	lb COD/lb VS-day	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
COD - WW Solids	lb COD/lb VS	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
COD - FOG	lb COD/lb VS	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
COD - FW	lb COD/lb VS	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76
COD Added - WW Solids	lb COD/day	42,502	51,203	52,087	44,865	54,051	54,983	47,228	56,898	57,880	49,592	59,745	60,776	51,955	62,592	63,673
COD Added - FOG	lb COD/day	56315	63797	64385	56315	63797	64385	56315	63797	64385	56315	63797	64385	56315	63797	64385
COD Added - FW	lb COD/day	0	0	0	35288	35288	35288	35288	35288	35288	35288	35288	35288	35288	35288	35288
Percent of Total COD Added as FOG	%	57%	55%	55%	41%	42%	42%	41%	41%	41%	40%	40%	40%	39%	39%	39%
Percent of WW Solids COD Added as FOG	%	133%	125%	124%	126%	118%	117%	119%	112%	111%	114%	107%	106%	108%	102%	101%
Digester VS Inventory, WW+FOG+FW, 3 Digesters	lb VSinv Total	314,032	326,191	324,009	331,066	339,382	337,402	333,427	341,606	339,685	335,644	343,687	341,822	337,730	345,638	343,826
Digester VS Inventory, WW+FOG+FW, 2 Digesters	lb VSinv Total	209,354	217,461	216,006	220,711	226,255	224,935	222,285	227,737	226,457	223,763	229,125	227,882	225,154	230,425	229,218
Digester VS Inventory, WW+FOG+FW, 1 Digester	lb VSinv Total	104,677	108,730	108,003	110,355	113,127	112,467	111,142	113,869	113,228	111,881	114,562	113,941	112,577	115,213	114,609
SELR, 3 Digesters	lb COD/lb VSinv-day	0.315	0.353	0.359	0.412	0.451	0.458	0.416	0.457	0.464	0.421	0.462	0.469	0.425	0.468	0.475
SELR, 2 Digesters	lb COD/lb VSinv-day	0.472	0.529	0.539	0.618	0.677	0.688	0.625	0.685	0.696	0.631	0.693	0.704	0.638	0.702	0.713
SELR, 1 Digester	lb COD/lb VSinv-day	0.944	1.058	1.078	1.237	1.354	1.375	1.249	1.370	1.391	1.262	1.386	1.408	1.275	1.403	1.425
Post-Digestion Solids Flow																
Total Hydraulic Flow	gpd	100,227	116,615	119,431	127,353	144,587	147,488	131,483	149,562	152,550	135,613	154,538	157,612	139,743	159,514	162,674
Post Digestion Total Solids	lb TS/day	18,034	21,594	21,949	24,929	28,673	29,048	25,830	29,758	30,151	26,730	30,842	31,255	27,630	31,927	32,358
Post Digestion Total Solids	ton TS/day	9.0	10.8	11.0	12.5	14.3	14.5	12.9	14.9	15.1	13.4	15.4	15.6	13.8	16.0	16.2
Post Digestion Solids Concentration, Combined	% TS	2.2%	2.2%	2.2%	2.3%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
Volatile Solids After Digestion	lb VS/day	11,029	13,217	13,436	14,591	16,894	17,125	15,150	17,568	17,810	15,710	18,241	18,496	16,269	18,915	19,181
VS/TS Ratio, Combined	% VS	61%	61%	61%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
Percent Solids Increase from Baseline	lb TS/day	682	4,242	4,598	7,578	11,322	11,696	8,478	12,406	12,800	9,378	13,491	13,903	10,278	14,575	15,006

		Thermophilic Digestion (TAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
Dewatering																
Polymer Dosage	lb active/DT	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Neat Polymer Active Content	lb active/lb neat	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Polymer Delivery Rate, FW	lb neat/day	162	194	198	224	258	261	232	268	271	241	278	281	249	287	291
Dewatered Cake Solids Content	%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%
Cake Solids	ton TS/day	9.02	10.80	10.97	12.46	14.34	14.52	12.91	14.88	15.08	13.36	15.42	15.63	13.82	15.96	16.18
Cake Solids	ton TS/yr	3,291	3,941	4,006	4,550	5,233	5,301	4,714	5,431	5,503	4,878	5,629	5,704	5,042	5,827	5,905
Cake Solids	wet ton/day	56	67	69	78	90	91	81	93	94	84	96	98	86	100	101
Cake Solids	wet ton/yr	20,570	24,630	25,036	28,435	32,705	33,133	29,462	33,943	34,391	30,489	35,180	35,650	31,516	36,417	36,908
Dewatered Cake Density	wet lb/cf	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cake Storage Bays - Existing	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Cake Storage Bays - New	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Cake Storage Volume per Bay	cy	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367
Cake Storage Volume Available	cy	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600
Storage Time Provided	days	79	66	65	57	50	49	55	48	47	53	46	46	52	45	44
Digester Gas Management																
Average Plant Power Demand	kWe	700	692	692	738	782	782	777	875	875	816	808	808	914	905	905
Average Plant Power Demand	kWh/month	510,661	505,279	505,279	539,057	570,678	570,678	567,454	638,625	638,625	595,850	589,569	589,569	666,974	660,864	660,864
Solar Power Production	kWe	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
CHP Power Demand	kWe	649	642	642	688	731	731	727	824	824	766	757	757	863	855	855
CHP Power Demand	kWh/month	473,889	468,507	468,507	502,285	533,906	533,906	530,682	601,853	601,853	559,078	552,797	552,797	630,202	624,092	624,092
Specific Digester Gas Production, WW Solids	scf/lb VS destroyed	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Digester Gas Methane Content, WW Solids	% CH4 by volume	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
Digester Gas Production, WW Solids	scf/day DG	268,205	323,116	328,693	283,119	341,083	346,970	298,033	359,050	365,248	312,947	377,018	383,525	327,860	394,985	401,802
Methane Production, WW Solids	scf/day CH4	160,923	193,869	197,216	169,871	204,650	208,182	178,820	215,430	219,149	187,768	226,211	230,115	196,716	236,991	241,081
Specific Digester Gas Production, FOG	scf/lb VSR	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Digester Gas Methane Content, FOG	% CH4 by volume	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Digester Gas Production, FOG	scf/day DG	276,719	313,486	316,376	276,719	313,486	316,376	276,719	313,486	316,376	276,719	313,486	316,376	276,719	313,486	316,376
Methane Production, FOG	scf/day CH4	179,868	203,766	205,644	179,868	203,766	205,644	179,868	203,766	205,644	179,868	203,766	205,644	179,868	203,766	205,644
Digester Gas Production, WW Solids + FOG	scf/day DG	544,924	636,601	645,068	559,838	654,568	663,346	574,752	672,536	681,623	589,666	690,503	699,901	604,580	708,471	718,178
Digester Gas Production, WW Solids + FOG	scfm DG	378	442	448	389	455	461	399	467	473	409	480	486	420	492	499
Digester Gas Methane Production, WW Solids + FOG	scf/day CH4	340,790	397,635	402,860	349,739	408,415	413,826	358,687	419,196	424,793	367,635	429,976	435,759	376,584	440,757	446,726
Methane Content of Digester Gas, WW Solids + FOG	v/v	63%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%
Methane Yield, FW	scf CH4/lb FW TS digested	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Digester Gas Methane Content, FW	v/v	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Methane Production, FW	scf/day CH4	0	0	0	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082	138,082
Digester Gas Production, FW	scf/day DG	0	0	0	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434	212,434
Total Methane Production	scf/day CH4	340,790	397,635	402,860	487,821	546,498	551,908	496,769	557,278	562,875	505,718	568,058	573,841	514,666	578,839	584,808
Total Digester Gas Production	scf/day DG	544,924	636,601	645,068	772,272	867,003	875,780	787,186	884,970	894,057	802,100	902,937	912,335	817,014	920,905	930,612
Total Digester Gas Production	scfm DG	378	442	448	536	602	608	547	615	621	557	627	634	567	640	646
Energy Content Methane - HHV	BTU/scf HHV	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011	1011
Energy Content Methane - LHV	BTU/scf LHV	910	910	910	910	910	910	910	910	910	910	910	910	910	910	910
Net Digester Gas Methane Content	%CH4 by volume	63%	62%	62%	63%	63%	63%	63%	63%	63%	63%	63%	63%	63%	63%	63%
Net Digester Gas Energy Content	BTU/scf LHV	569	568	568	575	574	573	574	573	573	574	573	572	573	572	572
Wobbe Index	BTU/scf HHV	681	679	679	692	690	690	691	689	688	690	688	687	689	687	686
Gas Conditioning System Capacity (existing)	scfm	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Engine 1 Capacity (existing)	scfm	378	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Engine 2 Capacity (existing)	scfm	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
WGB Capacity (existing)	scfm	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150
Total Digester Gas Production	scfm	378	442	448	536	602	608	547	615	621	557	627	634	567	640	646
Digester Gas Production, WW Solids	scfm	186	224	228	197	237	241	207	249	254	217	262	266	228	274	279
Digester Gas Production, FOG	scfm	192	218	220	192	218	220	192	218	220	192	218	220	192	218	220
Digester Gas Production, FW	scfm	0	0	0	148	148	148	148	148	148	148	148	148	148	148	148
Digester Gas Energy, WW Solids	MMBTUf/day LHV	146	176	179	155	186	189	163	196	199	171	206	209	179	216	219
Digester Gas Energy, FOG	MMBTUf/day LHV	164	185	187	164	185	187	164	185	187	164	185	187	164	185	187
Digester Gas Energy, FW	MMBTUf/day LHV	0	0	0	126	126	126	126	126	126	126	126	126	126	126	126

		Thermophilic Digestion (TAD) w/ Additional Feedstock														
		2027			2032			2037			2042			2047		
	Units	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak	Annual Average	30-Day Peak	14-Day Peak
Total Digester Gas Energy	MMBTUf/day LHV	310	362	367	444	497	502	452	507	512	460	517	522	468	527	532
Digester Gas Energy, WW Solids	MMBTUf/day HHV	163	196	199	172	207	210	181	218	222	190	229	233	199	240	244
Digester Gas Energy, FOG	MMBTUf/day HHV	182	206	208	182	206	208	182	206	208	182	206	208	182	206	208
Digester Gas Energy, FW	MMBTUf/day HHV	0	0	0	140	140	140	140	140	140	140	140	140	140	140	140
Total Digester Gas Energy	MMBTUf/day HHV	345	402	407	493	553	558	502	563	569	511	574	580	520	585	591
Digester Gas Energy, WW Solids	kWf LHV	1,788	2,154	2,192	1,888	2,274	2,313	1,987	2,394	2,435	2,087	2,514	2,557	2,186	2,634	2,679
Digester Gas Energy, FOG	kWf LHV	1,999	2,264	2,285	1,999	2,264	2,285	1,999	2,264	2,285	1,999	2,264	2,285	1,999	2,264	2,285
Digester Gas Energy, FW	kWf LHV	0	0	0	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534
Total Digester Gas Energy	kWf LHV	3,787	4,419	4,477	5,421	6,073	6,133	5,520	6,193	6,255	5,620	6,313	6,377	5,719	6,432	6,499
Total Available Elec Energy from CHP (max)	kWe LHV	1,572	1,834	1,858	2,250	2,520	2,545	2,291	2,570	2,596	2,332	2,620	2,646	2,374	2,669	2,697
Heat and Power Production																
Digester Heat Loss Factor	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Heat Demand for WW Solids	MMBTUth/day	55	66	67	58	69	71	61	73	74	64	77	78	67	80	82
Heat Demand for FOG	MMBTUth/day	9	10	11	9	10	11	9	10	11	9	10	11	9	10	11
Heat Demand for FW	MMBTUth/day	0	0	0	17	17	17	17	17	17	17	17	17	17	17	17
Total Heat Demand	MMBTUth/day	63	76	78	83	96	98	86	100	102	89	104	106	92	107	109
Total Heat Demand	kWth	770	926	947	1013	1177	1199	1050	1222	1244	1087	1266	1289	1124	1311	1335
CHP																
CHP Electrical Efficiency	%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
CHP Heat Efficiency	%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
CHP Maximum Inlet Capacity - Existing	kWFuel/Engine LHV	3,784	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255
CHP Maximum Power Output - Existing	kWe/Engine	1,570	521	521	521	521	521	521	521	521	521	521	521	521	521	521
Equivalent Households per Engine	households/engine	1,256	417	417	417	417	417	417	417	417	417	417	417	417	417	417
CHP Digester Gas Demand	kWf LHV	1,564	1,546	1,546	1,658	1,762	1,762	1,752	1,987	1,987	1,845	1,825	1,825	2,080	2,060	2,060
CHP Total Digester Gas Demand	MMBTUfuel/hr LHV	5.3	5.3	5.3	5.7	6.0	6.0	6.0	6.8	6.8	6.3	6.2	6.2	7.1	7.0	7.0
CHP Total Digester Gas Demand	scfm	156	155	155	164	175	175	173	197	197	183	181	181	206	205	205
CHP Natural Gas Demand	MMBTUng/hr LHV	0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP Power Production	kWelec	649	642	642	688	731	731	727	824	824	766	757	757	863	855	855
CHP Power Production	kWh/yr	5,686,671	5,622,082	5,622,082	6,027,425	6,406,874	6,406,874	6,368,178	7,222,242	7,222,242	6,708,932	6,633,569	6,633,569	7,562,424	7,489,101	7,489,101
Average Household Power Demand	kWe/household	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Equivalent Number of Households Powered	-	519	513	513	550	585	585	582	660	660	613	606	606	691	684	684
CHP Turndown	%	19%	20%	20%	14%	9%	9%	9%	-3%	-3%	4%	5%	5%	-8%	-7%	-7%
Plant Electrical Demand Provided by CHP	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
CHP Heat Production	MMBTUth/hr	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.5	1.5	1.4	1.4	1.4	1.6	1.6	1.6
CHP Heat Production	MMBTUth/day	28	28	28	30	32	32	32	36	36	33	33	33	38	37	37
CHP Heat Additional	MMBTUth/day	-35	-48	-50	-53	-64	-66	-54	-64	-66	-56	-71	-73	-54	-70	-72
CHP Heat Production	kWth	346	342	342	366	389	389	387	439	439	408	403	403	460	455	455
CHP Heat Additional or Lost	kWth	-424	-585	-605	-646	-788	-809	-663	-783	-805	-679	-863	-886	-664	-856	-880
BOILER																
Boiler Efficiency	%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Boiler Heat Production	MMBTUth/day	35	48	50	53	64	66	54	64	66	56	71	73	54	70	72
Boiler Fuel Demand	MMBTUf/hr LHV	1.8	2.5	2.6	2.8	3.4	3.5	2.8	3.3	3.4	2.9	3.7	3.8	2.8	3.6	3.8
Boiler Fuel Demand	kWFuel	529.7	730.6	756.6	807.7	984.3	1011.2	828.0	978.0	1006.0	848.4	1078.5	1107.4	829.8	1069.2	1099.1
Boiler Fuel Demand	scfm	52.7	72.6	75.2	80.3	97.8	100.5	82.3	97.2	100.0	84.3	107.2	110.1	82.5	106.3	109.3
Digester Gas Available for Drying	MMBTUf/hr LHV	5.8	7.3	7.4	10.1	11.3	11.5	10.0	11.0	11.1	10.0	11.6	11.8	9.6	11.3	11.4
Digester Gas Available for Drying	scfm	169.2	214.3	217.5	292.4	329.8	333.1	291.2	320.3	323.8	290.0	338.6	342.2	278.7	328.4	332.1
Total Heat Production	MMBTUth/day	63.0	75.9	77.6	82.9	96.4	98.2	86.0	100.0	101.9	89.0	103.7	105.6	92.0	107.3	109.3
Extra Heat Needed	MMBTUth/day	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	0.0	0.0
Hauling																
Truck Size	wet tons/load	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Weekly Truckloads w/o Drying	loads/week	13.1	15.7	16.0	18.2	20.9	21.2	18.8	21.7	22.0	19.5	22.5	22.8	20.1	23.3	23.6
Hauling Distance for Dewatered Cake	mi/round trip	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
Specific Cost of Highway Hauling	\$/mi-ton	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Cost of Highway Hauling	\$/yr	689,255	N/A	N/A	952,796	N/A	N/A	987,205	N/A	N/A	1,021,614	N/A	N/A	1,056,023	N/A	N/A
Truck Mileage	mi/gal	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Diesel Used	gal/yr	28,295	N/A	N/A	39,113	N/A	N/A	40,526	N/A	N/A	41,938	N/A	N/A	43,351	N/A	N/A
CO2 emission factor, diesel	lb CO2e/gal	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
CO2e emitted from hauling	ton CO2e/yr	314	N/A	N/A	434	N/A	N/A	450	N/A	N/A	466	N/A	N/A	481	N/A	N/A

Appendix B. Revenue Analysis

Baseline: New Mesophilic Digester																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 32,393,404	\$ 33,358,000	\$ -	\$ -	\$ 34,366,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Total Capital Costs	\$ 32,393,404	\$ 33,358,000	\$ -	\$ -	\$ 34,366,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Labor	\$ 100,000	\$ 2,239,000	\$ -	\$ -	\$ 106,000	\$ 109,000	\$ 113,000	\$ 116,000	\$ 119,000	\$ 123,000	\$ 127,000	\$ 130,000	\$ 134,000	\$ 138,000	\$ 143,000	\$ 147,000	\$ 151,000	\$ 156,000	\$ 160,000	\$ 165,000	\$ 170,000	\$ 175,000	\$ 181,000
Electricity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 599,257	\$ 13,423,000	\$ -	\$ -	\$ 636,000	\$ 655,000	\$ 674,000	\$ 695,000	\$ 716,000	\$ 737,000	\$ 759,000	\$ 782,000	\$ 805,000	\$ 830,000	\$ 854,000	\$ 880,000	\$ 906,000	\$ 934,000	\$ 962,000	\$ 990,000	\$ 1,020,000	\$ 1,051,000	\$ 1,082,000
Chemicals	\$ 110,718	\$ 2,515,000			\$ 117,000	\$ 121,000	\$ 125,000	\$ 128,000	\$ 132,000	\$ 136,000	\$ 140,000	\$ 144,000	\$ 149,000	\$ 153,000	\$ 158,000	\$ 163,000	\$ 167,000	\$ 172,000	\$ 178,000	\$ 183,000	\$ 188,000	\$ 194,000	\$ 200,000
Biosolids Hauling/Disposal	\$ 1,011,569	\$ 22,658,000	\$ -	\$ -	\$ 1,073,000	\$ 1,105,000	\$ 1,139,000	\$ 1,173,000	\$ 1,208,000	\$ 1,244,000	\$ 1,281,000	\$ 1,320,000	\$ 1,359,000	\$ 1,400,000	\$ 1,442,000	\$ 1,486,000	\$ 1,530,000	\$ 1,576,000	\$ 1,623,000	\$ 1,672,000	\$ 1,722,000	\$ 1,774,000	\$ 1,827,000
Total Annual Operating Costs	\$ 1,821,544	\$ 40,835,000	\$ -	\$ -	\$ 1,932,000	\$ 1,990,000	\$ 2,051,000	\$ 2,112,000	\$ 2,175,000	\$ 2,240,000	\$ 2,307,000	\$ 2,376,000	\$ 2,447,000	\$ 2,521,000	\$ 2,597,000	\$ 2,676,000	\$ 2,754,000	\$ 2,838,000	\$ 2,923,000	\$ 3,010,000	\$ 3,100,000	\$ 3,194,000	\$ 3,290,000
Annual Revenue (HSW Tipping Fees)	\$ (380,874)	\$ (8,659,000)			\$ (404,000)	\$ (416,000)	\$ (429,000)	\$ (442,000)	\$ (455,000)	\$ (468,000)	\$ (482,000)	\$ (497,000)	\$ (512,000)	\$ (527,000)	\$ (543,000)	\$ (559,000)	\$ (576,000)	\$ (593,000)	\$ (611,000)	\$ (630,000)	\$ (648,000)	\$ (668,000)	\$ (688,000)
Annual Revenue (Renewable Energy)	\$ -	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Revenues	\$ (380,874)	\$ (8,659,000)	\$ -	\$ -	\$ (404,000)	\$ (416,000)	\$ (429,000)	\$ (442,000)	\$ (455,000)	\$ (468,000)	\$ (482,000)	\$ (497,000)	\$ (512,000)	\$ (527,000)	\$ (543,000)	\$ (559,000)	\$ (576,000)	\$ (593,000)	\$ (611,000)	\$ (630,000)	\$ (648,000)	\$ (668,000)	\$ (688,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (35,894,000)	\$ (37,468,000)	\$ (39,090,000)	\$ (40,760,000)	\$ (42,480,000)	\$ (44,252,000)	\$ (46,077,000)	\$ (47,956,000)	\$ (49,891,000)	\$ (51,885,000)	\$ (53,939,000)	\$ (56,056,000)	\$ (58,234,000)	\$ (60,479,000)	\$ (62,791,000)	\$ (65,171,000)	\$ (67,623,000)	\$ (70,149,000)	\$ (72,751,000)
Total Cumulative Cashflow with Baseline Operating Costs Excluded			\$ -	\$ -	\$ (34,454,490)	\$ (34,574,980)	\$ (34,729,470)	\$ (34,917,960)	\$ (35,141,450)	\$ (35,400,940)	\$ (35,697,430)	\$ (36,032,920)	\$ (36,407,410)	\$ (36,822,900)	\$ (37,280,390)	\$ (37,781,880)	\$ (38,327,370)	\$ (38,918,860)	\$ (39,557,350)	\$ (40,244,840)	\$ (40,982,330)	\$ (41,771,820)	\$ (42,614,310)
Total Life Cycle Cost		\$ 65,534,000																					

CAPITAL COSTS																							
	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 300,000	\$ 6,720,000	\$ -	\$ -	\$ 318,000	\$ 328,000	\$ 338,000	\$ 348,000	\$ 358,000	\$ 369,000	\$ 380,000	\$ 391,000	\$ 403,000	\$ 415,000	\$ 428,000	\$ 441,000	\$ 454,000	\$ 467,000	\$ 481,000	\$ 496,000	\$ 511,000	\$ 526,000	\$ 542,000
Electricity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 1,023,801	\$ 22,932,000	\$ -	\$ -	\$ 1,086,000	\$ 1,119,000	\$ 1,152,000	\$ 1,187,000	\$ 1,222,000	\$ 1,259,000	\$ 1,297,000	\$ 1,336,000	\$ 1,376,000	\$ 1,417,000	\$ 1,460,000	\$ 1,503,000	\$ 1,549,000	\$ 1,595,000	\$ 1,643,000	\$ 1,692,000	\$ 1,743,000	\$ 1,795,000	\$ 1,849,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 2,455,583	\$ 55,054,000	\$ -	\$ -	\$ 2,604,000	\$ 2,684,000	\$ 2,764,000	\$ 2,847,000	\$ 2,932,000	\$ 3,020,000	\$ 3,111,000	\$ 3,204,000	\$ 3,300,000	\$ 3,399,000	\$ 3,502,000	\$ 3,606,000	\$ 3,715,000	\$ 3,825,000	\$ 3,940,000	\$ 4,059,000	\$ 4,181,000	\$ 4,306,000	\$ 4,435,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (1,567,258)	\$ (35,633,000)			\$ (1,663,000)	\$ (1,713,000)	\$ (1,764,000)	\$ (1,817,000)	\$ (1,871,000)	\$ (1,928,000)	\$ (1,985,000)	\$ (2,045,000)	\$ (2,106,000)	\$ (2,169,000)	\$ (2,235,000)	\$ (2,302,000)	\$ (2,371,000)	\$ (2,442,000)	\$ (2,515,000)	\$ (2,590,000)	\$ (2,668,000)	\$ (2,748,000)	\$ (2,831,000)
Total Revenues	\$ (2,790,004)	\$ (63,432,000)	\$ -	\$ -	\$ (2,960,000)	\$ (3,049,000)	\$ (3,140,000)	\$ (3,234,000)	\$ (3,331,000)	\$ (3,431,000)	\$ (3,534,000)	\$ (3,640,000)	\$ (3,750,000)	\$ (3,862,000)	\$ (3,978,000)	\$ (4,097,000)	\$ (4,220,000)	\$ (4,347,000)	\$ (4,477,000)	\$ (4,611,000)	\$ (4,750,000)	\$ (4,892,000)	\$ (5,039,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (58,153,000)	\$ (57,788,000)	\$ (57,412,000)	\$ (57,025,000)	\$ (56,626,000)	\$ (56,215,000)	\$ (55,792,000)	\$ (55,356,000)	\$ (54,906,000)	\$ (54,443,000)	\$ (53,967,000)	\$ (53,476,000)	\$ (52,971,000)	\$ (52,449,000)	\$ (51,912,000)	\$ (51,360,000)	\$ (50,791,000)	\$ (50,205,000)	\$ (49,601,000)
Total Cumulative Cashflow with Baseline Operating Costs Excluded			\$ -	\$ -	\$ (56,625,000)	\$ (54,686,000)	\$ (52,688,000)	\$ (50,631,000)	\$ (48,512,000)	\$ (46,329,000)	\$ (44,081,000)	\$ (41,766,000)	\$ (39,381,000)	\$ (36,924,000)	\$ (34,394,000)	\$ (31,786,000)	\$ (29,103,000)	\$ (26,336,000)	\$ (23,487,000)	\$ (20,555,000)	\$ (17,534,000)	\$ (14,422,000)	\$ (11,216,000)
Cashflow Difference with Baseline			\$ -	\$ -	\$ (22,170,510)	\$ (20,111,020)	\$ (17,958,530)	\$ (15,713,040)	\$ (13,370,550)	\$ (10,928,060)	\$ (8,383,570)	\$ (5,733,080)	\$ (2,973,590)	\$ (101,100)	\$ 2,886,390	\$ 5,995,880	\$ 9,224,370	\$ 12,582,860	\$ 16,070,350	\$ 19,689,840	\$ 23,448,330	\$ 27,349,820	\$ 31,398,310
Total Life Cycle Cost		\$ 48,414,000																					

Table 1a: Renewable Electricity Commodity Value + Incentives under 2022 Proposed RFS																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Total Capital Costs	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Labor	\$ 300,000	\$ 6,720,000	\$ -	\$ -	\$ 318,000	\$ 328,000	\$ 338,000	\$ 348,000	\$ 358,000	\$ 369,000	\$ 380,000	\$ 391,000	\$ 403,000	\$ 415,000	\$ 428,000	\$ 441,000	\$ 454,000	\$ 467,000	\$ 481,000	\$ 496,000	\$ 511,000	\$ 526,000	\$ 542,000
Electricity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Maintenance	\$ 1,023,801	\$ 22,932,000	\$ -	\$ -	\$ 1,086,000	\$ 1,119,000	\$ 1,152,000	\$ 1,187,000	\$ 1,222,000	\$ 1,259,000	\$ 1,297,000	\$ 1,336,000	\$ 1,376,000	\$ 1,417,000	\$ 1,460,000	\$ 1,503,000	\$ 1,549,000	\$ 1,595,000	\$ 1,643,000	\$ 1,692,000	\$ 1,743,000	\$ 1,795,000	\$ 1,849,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 2,455,583	\$ 55,054,000	\$ -	\$ -	\$ 2,604,000	\$ 2,684,000	\$ 2,764,000	\$ 2,847,000	\$ 2,932,000	\$ 3,020,000	\$ 3,111,000	\$ 3,204,000	\$ 3,300,000	\$ 3,399,000	\$ 3,502,000	\$ 3,606,000	\$ 3,715,000	\$ 3,825,000	\$ 3,940,000	\$ 4,059,000	\$ 4,181,000	\$ 4,306,000	\$ 4,435,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (3,442,171)	\$ (78,259,000)			\$ (3,652,000)	\$ (3,761,000)	\$ (3,874,000)	\$ (3,990,000)	\$ (4,110,000)	\$ (4,233,000)	\$ (4,360,000)	\$ (4,491,000)	\$ (4,626,000)	\$ (4,765,000)	\$ (4,908,000)	\$ (5,055,000)	\$ (5,207,000)	\$ (5,363,000)	\$ (5,524,000)	\$ (5,689,000)	\$ (5,860,000)	\$ (6,036,000)	\$ (6,217,000)
Total Revenues	\$ (4,664,917)	#####	\$ -	\$ -	\$ (4,949,000)	\$ (5,097,000)	\$ (5,250,000)	\$ (5,408,000)	\$ (5,570,000)	\$ (5,737,000)	\$ (5,909,000)	\$ (6,087,000)	\$ (6,269,000)	\$ (6,457,000)	\$ (6,651,000)	\$ (6,851,000)	\$ (7,056,000)	\$ (7,268,000)	\$ (7,486,000)	\$ (7,710,000)	\$ (7,942,000)	\$ (8,180,000)	\$ (8,425,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (56,164,000)	\$ (53,751,000)	\$ (51,265,000)	\$ (48,704,000)	\$ (46,066,000)	\$ (43,349,000)	\$ (40,551,000)	\$ (37,668,000)	\$ (34,699,000)	\$ (31,641,000)	\$ (28,492,000)	\$ (25,247,000)	\$ (21,906,000)	\$ (18,463,000)	\$ (14,917,000)	\$ (11,266,000)	\$ (7,505,000)	\$ (3,631,000)	\$ 359,000
Total Cumulative Cashflow with Baseline Operating Costs Excluded			\$ -	\$ -	\$ (54,636,000)	\$ (50,649,000)	\$ (46,541,000)	\$ (42,310,000)	\$ (37,952,000)	\$ (33,463,000)	\$ (28,840,000)	\$ (24,078,000)	\$ (19,174,000)	\$ (14,122,000)	\$ (8,919,000)	\$ (3,557,000)	\$ 1,962,000	\$ 7,650,000	\$ 13,508,000	\$ 19,539,000	\$ 25,752,000	\$ 32,152,000	\$ 38,744,000
Cashflow Difference with Baseline			\$ -	\$ -	\$ (20,181,510)	\$ (16,074,020)	\$ (11,811,530)	\$ (7,392,040)	\$ (2,810,550)	\$ 1,937,940	\$ 6,857,430	\$ 11,954,920	\$ 17,233,410	\$ 22,700,900	\$ 28,361,390	\$ 34,224,880	\$ 40,289,370	\$ 46,568,860	\$ 53,065,350	\$ 59,783,840	\$ 66,734,330	\$ 73,923,820	\$ 81,358,310
Total Life Cycle Cost		\$ 5,788,000																					

Option 1c: Commodity Value + Voluntary Market																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 300,000	\$ 6,720,000	\$ -	\$ -	\$ 318,000	\$ 328,000	\$ 338,000	\$ 348,000	\$ 358,000	\$ 369,000	\$ 380,000	\$ 391,000	\$ 403,000	\$ 415,000	\$ 428,000	\$ 441,000	\$ 454,000	\$ 467,000	\$ 481,000	\$ 496,000	\$ 511,000	\$ 526,000	\$ 542,000
Electricity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 1,023,801	\$ 22,932,000	\$ -	\$ -	\$ 1,086,000	\$ 1,119,000	\$ 1,152,000	\$ 1,187,000	\$ 1,222,000	\$ 1,259,000	\$ 1,297,000	\$ 1,336,000	\$ 1,376,000	\$ 1,417,000	\$ 1,460,000	\$ 1,503,000	\$ 1,549,000	\$ 1,595,000	\$ 1,643,000	\$ 1,692,000	\$ 1,743,000	\$ 1,795,000	\$ 1,849,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 2,455,583	\$ 55,054,000	\$ -	\$ -	\$ 2,604,000	\$ 2,684,000	\$ 2,764,000	\$ 2,847,000	\$ 2,932,000	\$ 3,020,000	\$ 3,111,000	\$ 3,204,000	\$ 3,300,000	\$ 3,399,000	\$ 3,502,000	\$ 3,606,000	\$ 3,715,000	\$ 3,825,000	\$ 3,940,000	\$ 4,059,000	\$ 4,181,000	\$ 4,306,000	\$ 4,435,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (416,275)	\$ (9,466,000)			\$ (442,000)	\$ (455,000)	\$ (469,000)	\$ (483,000)	\$ (497,000)	\$ (512,000)	\$ (527,000)	\$ (543,000)	\$ (559,000)	\$ (576,000)	\$ (594,000)	\$ (611,000)	\$ (630,000)	\$ (649,000)	\$ (668,000)	\$ (688,000)	\$ (709,000)	\$ (730,000)	\$ (752,000)
Total Revenues	\$ (1,639,021)	\$ (37,265,000)	\$ -	\$ -	\$ (1,739,000)	\$ (1,791,000)	\$ (1,845,000)	\$ (1,900,000)	\$ (1,957,000)	\$ (2,016,000)	\$ (2,076,000)	\$ (2,139,000)	\$ (2,203,000)	\$ (2,269,000)	\$ (2,337,000)	\$ (2,407,000)	\$ (2,479,000)	\$ (2,554,000)	\$ (2,630,000)	\$ (2,709,000)	\$ (2,790,000)	\$ (2,874,000)	\$ (2,960,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (59,374,000)	\$ (60,267,000)	\$ (61,186,000)	\$ (62,133,000)	\$ (63,108,000)	\$ (64,112,000)	\$ (65,147,000)	\$ (66,212,000)	\$ (67,309,000)	\$ (68,439,000)	\$ (69,604,000)	\$ (70,803,000)	\$ (72,039,000)	\$ (73,310,000)	\$ (74,620,000)	\$ (75,970,000)	\$ (77,361,000)	\$ (78,793,000)	\$ (80,268,000)
Total Cumulative Cashflow with Baseline																							
Operating Costs Excluded			\$ -	\$ -	\$ (57,846,000)	\$ (57,165,000)	\$ (56,462,000)	\$ (55,739,000)	\$ (54,994,000)	\$ (54,226,000)	\$ (53,436,000)	\$ (52,622,000)	\$ (51,784,000)	\$ (50,920,000)	\$ (50,031,000)	\$ (49,113,000)	\$ (48,171,000)	\$ (47,197,000)	\$ (46,195,000)	\$ (45,165,000)	\$ (44,104,000)	\$ (43,010,000)	\$ (41,883,000)
Cashflow Difference with Baseline			\$ -	\$ -	\$ (23,391,510)	\$ (22,590,020)	\$ (21,732,530)	\$ (20,821,040)	\$ (19,852,550)	\$ (18,825,060)	\$ (17,738,570)	\$ (16,589,080)	\$ (15,376,590)	\$ (14,097,100)	\$ (12,750,610)	\$ (11,331,120)	\$ (9,843,630)	\$ (8,278,140)	\$ (6,637,650)	\$ (4,920,160)	\$ (3,121,670)	\$ (1,238,180)	\$ 731,310
Total Life Cycle Cost		\$ 74,581,000																					
Option 1a: Renewable Electricity Commodity Value + Incentives (Max Revenue Potential)																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 300,000	\$ 6,720,000	\$ -	\$ -	\$ 318,000	\$ 328,000	\$ 338,000	\$ 348,000	\$ 358,000	\$ 369,000	\$ 380,000	\$ 391,000	\$ 403,000	\$ 415,000	\$ 428,000	\$ 441,000	\$ 454,000	\$ 467,000	\$ 481,000	\$ 496,000	\$ 511,000	\$ 526,000	\$ 542,000
Electricity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 1,023,801	\$ 22,932,000	\$ -	\$ -	\$ 1,086,000	\$ 1,119,000	\$ 1,152,000	\$ 1,187,000	\$ 1,222,000	\$ 1,259,000	\$ 1,297,000	\$ 1,336,000	\$ 1,376,000	\$ 1,417,000	\$ 1,460,000	\$ 1,503,000	\$ 1,549,000	\$ 1,595,000	\$ 1,643,000	\$ 1,692,000	\$ 1,743,000	\$ 1,795,000	\$ 1,849,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 2,455,583	\$ 55,054,000	\$ -	\$ -	\$ 2,604,000	\$ 2,684,000	\$ 2,764,000	\$ 2,847,000	\$ 2,932,000	\$ 3,020,000	\$ 3,111,000	\$ 3,204,000	\$ 3,300,000	\$ 3,399,000	\$ 3,502,000	\$ 3,606,000	\$ 3,715,000	\$ 3,825,000	\$ 3,940,000	\$ 4,059,000	\$ 4,181,000	\$ 4,306,000	\$ 4,435,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (2,807,289)	\$ (63,826,000)			\$ (2,978,000)	\$ (3,068,000)	\$ (3,160,000)	\$ (3,254,000)	\$ (3,352,000)	\$ (3,453,000)	\$ (3,556,000)	\$ (3,663,000)	\$ (3,773,000)	\$ (3,886,000)	\$ (4,003,000)	\$ (4,123,000)	\$ (4,246,000)	\$ (4,374,000)	\$ (4,505,000)	\$ (4,640,000)	\$ (4,779,000)	\$ (4,923,000)	\$ (5,070,000)
Total Revenues	\$ (4,030,035)	\$ (91,625,000)	\$ -	\$ -	\$ (4,275,00																		

Option 1A: Renewable Electricity Commodity Value + Incentives (Low Revenue Potential)																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 55,150,061	\$ 56,792,000	\$ -	\$ -	\$ 58,509,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 300,000	\$ 6,720,000	\$ -	\$ -	\$ 318,000	\$ 328,000	\$ 338,000	\$ 348,000	\$ 358,000	\$ 369,000	\$ 380,000	\$ 391,000	\$ 403,000	\$ 415,000	\$ 428,000	\$ 441,000	\$ 454,000	\$ 467,000	\$ 481,000	\$ 496,000	\$ 511,000	\$ 526,000	\$ 542,000
Electricity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 1,023,801	\$ 22,932,000	\$ -	\$ -	\$ 1,086,000	\$ 1,119,000	\$ 1,152,000	\$ 1,187,000	\$ 1,222,000	\$ 1,259,000	\$ 1,297,000	\$ 1,336,000	\$ 1,376,000	\$ 1,417,000	\$ 1,460,000	\$ 1,503,000	\$ 1,549,000	\$ 1,595,000	\$ 1,643,000	\$ 1,692,000	\$ 1,743,000	\$ 1,795,000	\$ 1,849,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 2,455,583	\$ 55,054,000	\$ -	\$ -	\$ 2,604,000	\$ 2,684,000	\$ 2,764,000	\$ 2,847,000	\$ 2,932,000	\$ 3,020,000	\$ 3,111,000	\$ 3,204,000	\$ 3,300,000	\$ 3,399,000	\$ 3,502,000	\$ 3,606,000	\$ 3,715,000	\$ 3,825,000	\$ 3,940,000	\$ 4,059,000	\$ 4,181,000	\$ 4,306,000	\$ 4,435,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (378,432)	\$ (8,604,000)			\$ (401,000)	\$ (414,000)	\$ (426,000)	\$ (439,000)	\$ (452,000)	\$ (465,000)	\$ (479,000)	\$ (494,000)	\$ (509,000)	\$ (524,000)	\$ (540,000)	\$ (556,000)	\$ (572,000)	\$ (590,000)	\$ (607,000)	\$ (625,000)	\$ (644,000)	\$ (664,000)	\$ (683,000)
Total Revenues	\$ (1,601,178)	\$ (36,403,000)	\$ -	\$ -	\$ (1,699,000)	\$ (1,750,000)	\$ (1,802,000)	\$ (1,856,000)	\$ (1,912,000)	\$ (1,969,000)	\$ (2,028,000)	\$ (2,089,000)	\$ (2,152,000)	\$ (2,216,000)	\$ (2,283,000)	\$ (2,351,000)	\$ (2,422,000)	\$ (2,495,000)	\$ (2,569,000)	\$ (2,647,000)	\$ (2,726,000)	\$ (2,808,000)	\$ (2,892,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (59,414,000)	\$ (60,348,000)	\$ (61,310,000)	\$ (62,301,000)	\$ (63,321,000)	\$ (64,372,000)	\$ (65,455,000)	\$ (66,570,000)	\$ (67,718,000)	\$ (68,901,000)	\$ (70,120,000)	\$ (71,375,000)	\$ (72,668,000)	\$ (73,998,000)	\$ (75,369,000)	\$ (76,781,000)	\$ (78,236,000)	\$ (79,734,000)	\$ (81,277,000)
Total Cumulative Cashflow with Baseline Operating Costs Excluded			\$ -	\$ -	\$ (57,886,000)	\$ (57,246,000)	\$ (56,586,000)	\$ (55,907,000)	\$ (55,207,000)	\$ (54,486,000)	\$ (53,744,000)	\$ (52,980,000)	\$ (52,193,000)	\$ (51,382,000)	\$ (50,547,000)	\$ (49,685,000)	\$ (48,800,000)	\$ (47,885,000)	\$ (46,944,000)	\$ (45,976,000)	\$ (44,979,000)	\$ (43,951,000)	\$ (42,892,000)
Cashflow Difference with Baseline			\$ -	\$ -	\$ (23,431,510)	\$ (22,671,020)	\$ (21,856,530)	\$ (20,989,040)	\$ (20,065,550)	\$ (19,085,060)	\$ (18,046,570)	\$ (16,947,080)	\$ (15,785,590)	\$ (14,559,100)	\$ (13,266,610)	\$ (11,903,120)	\$ (10,472,630)	\$ (8,966,140)	\$ (7,386,650)	\$ (5,731,160)	\$ (3,996,670)	\$ (2,179,180)	\$ (277,690)
Total Life Cycle Cost		\$ 75,443,000																					
Option 1a-ii w/MHP+TAD: Rewenable Energy (Tap Incentive/credit markets)																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 66,495,129	\$ 68,475,000	\$ -	\$ -	\$ 70,545,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 66,495,129	\$ 68,475,000	\$ -	\$ -	\$ 70,545,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 300,000	\$ 6,720,000	\$ -	\$ -	\$ 318,000	\$ 328,000	\$ 338,000	\$ 348,000	\$ 358,000	\$ 369,000	\$ 380,000	\$ 391,000	\$ 403,000	\$ 415,000	\$ 428,000	\$ 441,000	\$ 454,000	\$ 467,000	\$ 481,000	\$ 496,000	\$ 511,000	\$ 526,000	\$ 542,000
Electricity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 1,141,047	\$ 25,559,000	\$ -	\$ -	\$ 1,211,000	\$ 1,247,000	\$ 1,284,000	\$ 1,323,000	\$ 1,362,000	\$ 1,403,000	\$ 1,445,000	\$ 1,489,000	\$ 1,533,000	\$ 1,579,000	\$ 1,627,000	\$ 1,676,000	\$ 1,726,000	\$ 1,778,000	\$ 1,831,000	\$ 1,886,000	\$ 1,943,000	\$ 2,001,000	\$ 2,061,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 591,078	\$ 13,240,000	\$ -	\$ -	\$ 627,000	\$ 646,000	\$ 665,000	\$ 685,000	\$ 706,000	\$ 727,000	\$ 749,000	\$ 771,000	\$ 794,000	\$ 818,000	\$ 843,000	\$ 868,000	\$ 894,000	\$ 921,000	\$ 949,000	\$ 977,000	\$ 1,006,000	\$ 1,036,000	\$ 1,068,000
Total Annual Operating Costs	\$ 2,176,703	\$ 48,807,000	\$ -	\$ -	\$ 2,309,000	\$ 2,379,000	\$ 2,450,000	\$ 2,524,000	\$ 2,599,000	\$ 2,677,000	\$ 2,757,000	\$ 2,840,000	\$ 2,924,000	\$ 3,012,000	\$ 3,104,000	\$ 3,197,000	\$ 3,293,000	\$ 3,391,000	\$ 3,493,000	\$ 3,598,000	\$ 3,706,000	\$ 3,817,000	\$ 3,932,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (1,716,728)	\$ (39,031,000)			\$ (1,821,000)	\$ (1,876,000)	\$ (1,932,000)	\$ (1,990,000)	\$ (2,050,000)	\$ (2,111,000)	\$ (2,175,000)	\$ (2,240,000)	\$ (2,307,000)	\$ (2,376,000)	\$ (2,448,000)	\$ (2,521,000)	\$ (2,597,000)	\$ (2,675,000)	\$ (2,755,000)	\$ (2,837,000)	\$ (2,923,000)	\$ (3,010,000)	\$ (3,101,000)
Total Revenues	\$ (2,939,474)	\$ (66,830,000)	\$ -	\$ -	\$ (3,118,000)	\$ (3,212,000)	\$ (3,308,000)	\$ (3,408,000)	\$ (3,510,000)	\$ (3,615,000)	\$ (3,724,000)	\$ (3,835,000)	\$ (3,950,000)	\$ (4,069,000)	\$ (4,191,000)	\$ (4,317,000)	\$ (4,446,000)	\$ (4,580,000)	\$ (4,717,000)	\$ (4,859,000)	\$ (5,004,000)	\$ (5,154,000)	\$ (5,309,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (69,736,000)	\$ (68,903,000)	\$ (68,045,000)	\$ (67,161,000)	\$ (66,250,000)	\$ (65,312,000)	\$ (64,345,000)	\$ (63,350,000)	\$ (62,324,000)	\$ (61,267,000)	\$ (60,180,000)	\$ (59,060,000)	\$ (57,907,000)	\$ (56,718,000)	\$ (55,494,000)	\$ (54,233,000)	\$ (52,935,000)	\$ (51,598,000)	\$ (50,221,000)
Total Cumulative Cashflow with Baseline Operating Costs Excluded			\$ -	\$ -	\$ (68,208,000)	\$ (65,801,000)	\$ (63,321,000)	\$ (60,767,000)	\$ (58,136,000)	\$ (55,426,000)	\$ (52,634,000)	\$ (49,760,000)	\$ (46,799,000)	\$ (43,748,000)	\$ (40,607,000)	\$ (37,370,000)	\$ (34,039,000)	\$ (30,605,000)	\$ (27,069,000)	\$ (23,428,000)	\$ (19,678,000)	\$ (15,815,000)	\$ (11,836,000)
Cashflow Difference with Baseline			\$ -	\$ -	\$ (33,753,510)	\$ (31,226,020)	\$ (28,591,530)	\$ (25,849,040)	\$ (22,994,550)	\$ (20,025,060)	\$ (16,936,570)	\$ (13,727,080)	\$ (10,391,590)	\$ (6,925,100)	\$ (3,326,610)	\$ 411,880	\$ 4,288,370	\$ 8,313,860	\$ 12,488,350	\$ 16,816,840	\$ 21,304,330	\$ 25,956,820	\$ 30,778,310
Total Life Cycle Cost		\$ 50,452,000																					

Baseline: New Mesophilic Digester																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 32,393,404	\$ 33,358,000	\$ -	\$ -	\$ 34,366,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 32,393,404	\$ 33,358,000	\$ -	\$ -	\$ 34,366,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 100,000	\$ 2,239,000	\$ -	\$ -	\$ 106,000	\$ 109,000	\$ 113,000	\$ 116,000	\$ 119,000	\$ 123,000	\$ 127,000	\$ 130,000	\$ 134,000	\$ 138,000	\$ 143,000	\$ 147,000	\$ 151,000	\$ 156,000	\$ 160,000	\$ 165,000	\$ 170,000	\$ 175,000	\$ 181,000
Electricity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 599,257	\$ 13,423,000	\$ -	\$ -	\$ 636,000	\$ 655,000	\$ 674,000	\$ 695,000	\$ 716,000	\$ 737,000	\$ 759,000	\$ 782,000	\$ 805,000	\$ 830,000	\$ 854,000	\$ 880,000	\$ 906,000	\$ 934,000	\$ 962,000	\$ 990,000	\$ 1,020,000	\$ 1,051,000	\$ 1,082,000
Chemicals	\$ 110,718	\$ 2,515,000			\$ 117,000	\$ 121,000	\$ 125,000	\$ 128,000	\$ 132,000	\$ 136,000	\$ 140,000	\$ 144,000	\$ 149,000	\$ 153,000	\$ 158,000	\$ 163,000	\$ 167,000	\$ 172,000	\$ 178,000	\$ 183,000	\$ 188,000	\$ 194,000	\$ 200,000
Biosolids Hauling/Disposal	\$ 1,011,569	\$ 22,658,000	\$ -	\$ -	\$ 1,073,000	\$ 1,105,000	\$ 1,139,000	\$ 1,173,000	\$ 1,208,000	\$ 1,244,000	\$ 1,281,000	\$ 1,320,000	\$ 1,359,000	\$ 1,400,000	\$ 1,442,000	\$ 1,486,000	\$ 1,530,000	\$ 1,576,000	\$ 1,623,000	\$ 1,672,000	\$ 1,722,000	\$ 1,774,000	\$ 1,827,000
Total Annual Operating Costs	\$ 1,821,544	\$ 40,835,000	\$ -	\$ -	\$ 1,932,000	\$ 1,990,000	\$ 2,051,000	\$ 2,112,000	\$ 2,175,000	\$ 2,240,000	\$ 2,307,000	\$ 2,376,000	\$ 2,447,000	\$ 2,521,000	\$ 2,597,000	\$ 2,676,000	\$ 2,754,000	\$ 2,838,000	\$ 2,923,000	\$ 3,010,000	\$ 3,100,000	\$ 3,194,000	\$ 3,290,000
Annual Revenue (HSW Tipping Fees)	\$ (380,874)	\$ (8,659,000)			\$ (404,000)	\$ (416,000)	\$ (429,000)	\$ (442,000)	\$ (455,000)	\$ (468,000)	\$ (482,000)	\$ (497,000)	\$ (512,000)	\$ (527,000)	\$ (543,000)	\$ (559,000)	\$ (576,000)	\$ (593,000)	\$ (611,000)	\$ (630,000)	\$ (648,000)	\$ (668,000)	\$ (688,000)
Annual Revenue (Renewable Energy)	\$ -	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Revenues	\$ (380,874)	\$ (8,659,000)	\$ -	\$ -	\$ (404,000)	\$ (416,000)	\$ (429,000)	\$ (442,000)	\$ (455,000)	\$ (468,000)	\$ (482,000)	\$ (497,000)	\$ (512,000)	\$ (527,000)	\$ (543,000)	\$ (559,000)	\$ (576,000)	\$ (593,000)	\$ (611,000)	\$ (630,000)	\$ (648,000)	\$ (668,000)	\$ (688,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (35,894,000)	\$ (37,468,000)	\$ (39,090,000)	\$ (40,760,000)	\$ (42,480,000)	\$ (44,252,000)	\$ (46,077,000)	\$ (47,956,000)	\$ (49,891,000)	\$ (51,885,000)	\$ (53,939,000)	\$ (56,056,000)	\$ (58,234,000)	\$ (60,479,000)	\$ (62,791,000)	\$ (65,171,000)	\$ (67,623,000)	\$ (70,149,000)	\$ (72,751,000)
Total Cumulative Cashflow with Baseline Operating Costs Excluded			\$ -	\$ -	\$ (34,454,490)	\$ (34,574,980)	\$ (34,729,470)	\$ (34,917,960)	\$ (35,141,450)	\$ (35,400,940)	\$ (35,697,430)	\$ (36,032,920)	\$ (36,407,410)	\$ (36,822,900)	\$ (37,280,390)	\$ (37,781,880)	\$ (38,327,370)	\$ (38,918,860)	\$ (39,557,350)	\$ (40,244,840)	\$ (40,982,330)	\$ (41,771,820)	\$ (42,614,310)
Total Life Cycle Cost		\$ 65,534,000																					

Option 2a: RNG Commodity Value + Incentives																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 61,656,196	\$ 63,492,000	\$ -	\$ -	\$ 65,411,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 61,656,196	\$ 63,492,000	\$ -	\$ -	\$ 65,411,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 300,000	\$ 6,720,000	\$ -	\$ -	\$ 318,000	\$ 328,000	\$ 338,000	\$ 348,000	\$ 358,000	\$ 369,000	\$ 380,000	\$ 391,000	\$ 403,000	\$ 415,000	\$ 428,000	\$ 441,000	\$ 454,000	\$ 467,000	\$ 481,000	\$ 496,000	\$ 511,000	\$ 526,000	\$ 542,000
Electricity/NG	\$ 1,384,956	\$ 31,022,000	\$ -	\$ -	\$ 1,469,000	\$ 1,513,000	\$ 1,559,000	\$ 1,606,000	\$ 1,654,000	\$ 1,703,000	\$ 1,754,000	\$ 1,807,000	\$ 1,861,000	\$ 1,917,000	\$ 1,975,000	\$ 2,034,000	\$ 2,095,000	\$ 2,158,000	\$ 2,222,000	\$ 2,289,000	\$ 2,358,000	\$ 2,429,000	\$ 2,501,000
Maintenance	\$ 1,021,003	\$ 22,869,000	\$ -	\$ -	\$ 1,083,000	\$ 1,116,000	\$ 1,149,000	\$ 1,184,000	\$ 1,219,000	\$ 1,256,000	\$ 1,293,000	\$ 1,332,000	\$ 1,372,000	\$ 1,413,000	\$ 1,456,000	\$ 1,499,000	\$ 1,544,000	\$ 1,591,000	\$ 1,638,000	\$ 1,688,000	\$ 1,738,000	\$ 1,790,000	\$ 1,844,000
Chemicals	\$ 144,577	\$ 3,239,000	\$ -	\$ -	\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 3,837,741	\$ 85,964,000	\$ -	\$ -	\$ 4,070,000	\$ 4,194,000	\$ 4,320,000	\$ 4,450,000	\$ 4,583,000	\$ 4,720,000	\$ 4,861,000	\$ 5,007,000	\$ 5,157,000	\$ 5,312,000	\$ 5,473,000	\$ 5,636,000	\$ 5,805,000	\$ 5,979,000	\$ 6,157,000	\$ 6,344,000	\$ 6,534,000	\$ 6,730,000	\$ 6,931,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,388,000)	\$ -	\$ -	\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (3,304,869)	\$ (74,026,000)	\$ -	\$ -	\$ (3,506,000)	\$ (3,611,000)	\$ (3,720,000)	\$ (3,831,000)	\$ (3,946,000)	\$ (4,065,000)	\$ (4,187,000)	\$ (4,312,000)	\$ (4,441,000)	\$ (4,575,000)	\$ (4,712,000)	\$ (4,853,000)	\$ (4,999,000)	\$ (5,149,000)	\$ (5,303,000)	\$ (5,462,000)	\$ (5,626,000)	\$ (5,795,000)	\$ (5,969,000)
Total Revenues	\$ (4,527,615)	\$ (101,414,000)	\$ -	\$ -	\$ (4,803,000)	\$ (4,947,000)	\$ (5,096,000)	\$ (5,249,000)	\$ (5,406,000)	\$ (5,568,000)	\$ (5,735,000)	\$ (5,908,000)	\$ (6,085,000)	\$ (6,267,000)	\$ (6,455,000)	\$ (6,649,000)	\$ (6,848,000)	\$ (7,054,000)	\$ (7,265,000)	\$ (7,483,000)	\$ (7,708,000)	\$ (7,939,000)	\$ (8,177,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (64,678,000)	\$ (63,925,000)	\$ (63,149,000)	\$ (62,350,000)	\$ (61,527,000)	\$ (60,679,000)	\$ (59,805,000)	\$ (58,904,000)	\$ (57,976,000)	\$ (57,021,000)	\$ (56,039,000)	\$ (55,026,000)	\$ (53,983,000)	\$ (52,908,000)	\$ (51,800,000)	\$ (50,661,000)	\$ (49,487,000)	\$ (48,278,000)	\$ (47,032,000)
Total Cumulative Cashflow with Baseline Operating Costs Excluded			\$ -	\$ -	\$ (63,150,000)	\$ (60,823,000)	\$ (58,425,000)	\$ (55,956,000)	\$ (53,413,000)	\$ (50,793,000)	\$ (48,094,000)	\$ (45,314,000)	\$ (42,451,000)	\$ (39,502,000)	\$ (36,466,000)	\$ (33,336,000)	\$ (30,115,000)	\$ (26,795,000)	\$ (23,375,000)	\$ (19,856,000)	\$ (16,230,000)	\$ (12,495,000)	\$ (8,647,000)
Lifecycle Cost Difference with Baseline			\$ -	\$ -	-28695510	-26248020	-23695530	-21038040	-18271550	-15392060	-12396570	-9281080	-6043590	-2679100	814390	4445880	8212370	12123860	16182350	20388840	24752330	29276820	33967310
Total Life Cycle Cost		\$ 48,042,000																					

Option 2a: RNG Commodity Value + Incentives under Proposed RFS																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 61,656,196	\$ 63,492,000	\$ -	\$ -	\$ 65,411,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 61,656,196	\$ 63,492,000	\$ -	\$ -	\$ 65,411,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 300,000	\$ 6,720,000	\$ -	\$ -	\$ 318,000	\$ 328,000	\$ 338,000	\$ 348,000	\$ 358,000	\$ 369,000	\$ 380,000	\$ 391,000	\$ 403,000	\$ 415,000	\$ 428,000	\$ 441,000	\$ 454,000	\$ 467,000	\$ 481,000	\$ 496,000	\$ 511,000	\$ 526,000	\$ 542,000
Electricity/NG	\$ 1,384,956	\$ 31,022,000	\$ -	\$ -	\$ 1,469,000	\$ 1,513,000	\$ 1,559,000	\$ 1,606,000	\$ 1,654,000	\$ 1,703,000	\$ 1,754,000	\$ 1,807,000	\$ 1,861,000	\$ 1,917,000	\$ 1,975,000	\$ 2,034,000	\$ 2,095,000	\$ 2,158,000	\$ 2,222,000	\$ 2,289,000	\$ 2,358,000	\$ 2,429,000	\$ 2,501,000
Maintenance	\$ 1,021,003	\$ 22,869,000	\$ -	\$ -	\$ 1,083,000	\$ 1,116,000	\$ 1,149,000	\$ 1,184,000	\$ 1,219,000	\$ 1,256,000	\$ 1,293,000	\$ 1,332,000	\$ 1,372,000	\$ 1,413,000	\$ 1,456,000	\$ 1,499,000	\$ 1,544,000	\$ 1,591,000	\$ 1,638,000	\$ 1,688,000	\$ 1,738,000	\$ 1,790,000	\$ 1,844,000
Chemicals	\$ 144,577	\$ 3,239,000	\$ -	\$ -	\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 3,837,741	\$ 85,964,000	\$ -	\$ -	\$ 4,070,000	\$ 4,194,000	\$ 4,320,000	\$ 4,450,000	\$ 4,583,000	\$ 4,720,000	\$ 4,861,000	\$ 5,007,000	\$ 5,157,000	\$ 5,312,000	\$ 5,473,000	\$ 5,636,000	\$ 5,805,000	\$ 5,979,000	\$ 6,157,000	\$ 6,344,000	\$ 6,534,000	\$ 6,730,000	\$ 6,931,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,388,000)	\$ -	\$ -	\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (4,350,649)	\$ (97,454,000)	\$ -	\$ -	\$ (4,616,000)	\$ (4,754,000)	\$ (4,897,000)	\$ (5,044,000)	\$ (5,195,000)	\$ (5,351,000)	\$ (5,511,000)	\$ (5,677,000)	\$ (5,847,000)	\$ (6,022,000)	\$ (6,203,000)	\$ (6,389,000)	\$ (6,581,000)	\$ (6,778,000)	\$ (6,982,000)	\$ (7,191,000)	\$ (7,407,000)	\$ (7,629,000)	\$ (7,858,000)
Total Revenues	\$ (5,573,395)	\$ (124,842,000)	\$ -	\$ -	\$ (5,913,000)	\$ (6,090,000)	\$ (6,273,000)	\$ (6,461,000)	\$ (6,655,000)	\$ (6,855,000)	\$ (7,060,000)	\$ (7,272,000)	\$ (7,490,000)	\$ (7,715,000)	\$ (7,946,000)	\$ (8,185,000)	\$ (8,430,000)	\$ (8,683,000)	\$ (8,944,000)	\$ (9,212,000)	\$ (9,488,000)	\$ (9,773,000)	\$ (10,066,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (63,568,000)	\$ (61,672,000)	\$ (59,719,000)	\$ (57,708,000)	\$ (55,636,000)	\$ (53,501,000)	\$ (51,302,000)	\$ (49,037,000)	\$ (46,704,000)	\$ (44,301,000)	\$ (41,828,000)	\$ (39,279,000)	\$ (36,654,000)	\$ (33,950,000)	\$ (31,163,000)	\$ (28,295,000)	\$ (25,341,000)	\$ (22,298,000)	\$ (19,163,000)
Total Cumulative Cashflow with Baseline																							
Operating Costs Excluded			\$ -	\$ -	\$ (62,040,000)	\$ (58,570,000)	\$ (54,995,000)	\$ (51,314,000)	\$ (47,522,000)	\$ (43,615,000)	\$ (39,591,000)	\$ (35,447,000)	\$ (31,179,000)	\$ (26,782,000)	\$ (22,255,000)	\$ (17,589,000)	\$ (12,786,000)	\$ (7,837,000)	\$ (2,738,000)	\$ 2,510,000	\$ 7,916,000	\$ 13,485,000	\$ 19,222,000
Lifecycle Cost Difference with Baseline			\$ -	\$ -	-27585510	-23995020	-20265530	-16396040	-12380550	-8214060	-3893570	585920	5228410	10040900	15025390	20192880	25541370	31081860	36819350	42754840	48898330	55256820	61836310
Total Life Cycle Cost		\$ 24,614,000																					

Option 2b-iii: Sell RNG to NWN (NWN pays gas treatment/injection)																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 36,981,437	\$ 38,083,000	\$ -	\$ -	\$ 39,234,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 36,981,437	\$ 38,083,000	\$ -	\$ -	\$ 39,234,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 200,000	\$ 4,481,000	\$ -	\$ -	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 253,000	\$ 261,000	\$ 269,000	\$ 277,000	\$ 285,000	\$ 294,000	\$ 303,000	\$ 312,000	\$ 321,000	\$ 331,000	\$ 340,000	\$ 351,000	\$ 361,000
Electricity/NG	\$ 1,384,956	\$ 31,022,000	\$ -	\$ -	\$ 1,469,000	\$ 1,513,000	\$ 1,559,000	\$ 1,606,000	\$ 1,654,000	\$ 1,703,000	\$ 1,754,000	\$ 1,807,000	\$ 1,861,000	\$ 1,917,000	\$ 1,975,000	\$ 2,034,000	\$ 2,095,000	\$ 2,158,000	\$ 2,222,000	\$ 2,289,000	\$ 2,358,000	\$ 2,429,000	\$ 2,501,000
Maintenance	\$ 821,003	\$ 18,390,000	\$ -	\$ -	\$ 871,000	\$ 897,000	\$ 924,000	\$ 952,000	\$ 980,000	\$ 1,010,000	\$ 1,040,000	\$ 1,071,000	\$ 1,103,000	\$ 1,136,000	\$ 1,171,000	\$ 1,206,000	\$ 1,242,000	\$ 1,279,000	\$ 1,317,000	\$ 1,357,000	\$ 1,398,000	\$ 1,440,000	\$ 1,483,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 3,537,741	\$ 79,295,000	\$ -	\$ -	\$ 3,752,000	\$ 3,866,000	\$ 3,982,000	\$ 4,102,000	\$ 4,225,000	\$ 4,351,000	\$ 4,481,000	\$ 4,616,000	\$ 4,754,000	\$ 4,897,000	\$ 5,045,000	\$ 5,196,000	\$ 5,352,000	\$ 5,512,000	\$ 5,676,000	\$ 5,848,000	\$ 6,023,000	\$ 6,205,000	\$ 6,389,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (743,448)	\$ (16,904,000)			\$ (789,000)	\$ (812,000)	\$ (837,000)	\$ (862,000)	\$ (888,000)	\$ (914,000)	\$ (942,000)	\$ (970,000)	\$ (999,000)	\$ (1,029,000)	\$ (1,060,000)	\$ (1,092,000)	\$ (1,125,000)	\$ (1,158,000)	\$ (1,193,000)	\$ (1,229,000)	\$ (1,266,000)	\$ (1,304,000)	\$ (1,343,000)
Total Revenues	\$ (1,966,194)	\$ (44,703,000)	\$ -	\$ -	\$ (2,086,000)	\$ (2,149,000)	\$ (2,213,000)	\$ (2,279,000)	\$ (2,348,000)	\$ (2,418,000)	\$ (2,491,000)	\$ (2,565,000)	\$ (2,642,000)	\$ (2,722,000)	\$ (2,803,000)	\$ (2,887,000)	\$ (2,974,000)	\$ (3,063,000)	\$ (3,155,000)	\$ (3,250,000)	\$ (3,347,000)	\$ (3,448,000)	\$ (3,551,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (40,900,000)	\$ (42,617,000)	\$ (44,386,000)	\$ (46,209,000)	\$ (48,086,000)	\$ (50,019,000)	\$ (52,009,000)	\$ (54,060,000)	\$ (56,172,000)	\$ (58,347,000)	\$ (60,589,000)	\$ (62,898,000)	\$ (65,276,000)	\$ (67,725,000)	\$ (70,246,000)	\$ (72,844,000)	\$ (75,520,000)	\$ (78,277,000)	\$ (81,115,000)
Total Cumulative Cashflow with Baseline																							
Operating Costs Excluded			\$ -	\$ -	\$ (39,372,000)	\$ (39,515,000)	\$ (39,662,000)	\$ (39,815,000)	\$ (39,972,000)	\$ (40,133,000)	\$ (40,298,000)	\$ (40,470,000)	\$ (40,647,000)	\$ (40,828,000)	\$ (41,016,000)	\$ (41,208,000)	\$ (41,408,000)	\$ (41,612,000)	\$ (41,821,000)	\$ (42,039,000)	\$ (42,263,000)	\$ (42,494,000)	\$ (42,730,000)
Lifecycle Cost Difference with Baseline			\$ -	\$ -	-4917510	-4940020	-4932530	-4897040	-4830550	-4732060	-4600570	-4437080	-4239590	-4005100	-3735610	-3426120	-3080630	-2693140	-2263650	-1794160	-1280670	-722180	-115690
Total Life Cycle Cost		\$ 72,675,000																					

Option 3a: Hybrid (Baseload Cogen + Excess RNG to market+incentives)																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 66,300,277	\$ 68,274,000	\$ -	\$ -	\$ 70,338,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 66,300,277	\$ 68,274,000	\$ -	\$ -	\$ 70,338,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 250,000	\$ 5,598,000	\$ -	\$ -	\$ 265,000	\$ 273,000	\$ 281,000	\$ 290,000	\$ 299,000	\$ 307,000	\$ 317,000	\$ 326,000	\$ 336,000	\$ 346,000	\$ 356,000	\$ 367,000	\$ 378,000	\$ 389,000	\$ 401,000	\$ 413,000	\$ 426,000	\$ 438,000	\$ 452,000
Electricity/NG	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 1,022,253	\$ 22,899,000	\$ -	\$ -	\$ 1,085,000	\$ 1,117,000	\$ 1,151,000	\$ 1,185,000	\$ 1,221,000	\$ 1,257,000	\$ 1,295,000	\$ 1,334,000	\$ 1,374,000	\$ 1,415,000	\$ 1,457,000	\$ 1,501,000	\$ 1,546,000	\$ 1,593,000	\$ 1,640,000	\$ 1,690,000	\$ 1,740,000	\$ 1,793,000	\$ 1,846,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 2,404,035	\$ 53,899,000	\$ -	\$ -	\$ 2,550,000	\$ 2,627,000	\$ 2,706,000	\$ 2,787,000	\$ 2,872,000	\$ 2,956,000	\$ 3,046,000	\$ 3,137,000	\$ 3,231,000	\$ 3,328,000	\$ 3,427,000	\$ 3,530,000	\$ 3,636,000	\$ 3,745,000	\$ 3,857,000	\$ 3,974,000	\$ 4,093,000	\$ 4,216,000	\$ 4,342,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (1,619,558)	\$ (36,823,000)			\$ (1,718,000)	\$ (1,770,000)	\$ (1,823,000)	\$ (1,878,000)	\$ (1,934,000)	\$ (1,992,000)	\$ (2,052,000)	\$ (2,113,000)	\$ (2,177,000)	\$ (2,242,000)	\$ (2,309,000)	\$ (2,378,000)	\$ (2,450,000)	\$ (2,523,000)	\$ (2,599,000)	\$ (2,677,000)	\$ (2,757,000)	\$ (2,840,000)	\$ (2,925,000)
Total Revenues	\$ (2,842,304)	\$ (64,622,000)	\$ -	\$ -	\$ (3,015,000)	\$ (3,106,000)	\$ (3,199,000)	\$ (3,295,000)	\$ (3,394,000)	\$ (3,496,000)	\$ (3,601,000)	\$ (3,709,000)	\$ (3,820,000)	\$ (3,934,000)	\$ (4,052,000)	\$ (4,174,000)	\$ (4,299,000)	\$ (4,428,000)	\$ (4,561,000)	\$ (4,698,000)	\$ (4,839,000)	\$ (4,984,000)	\$ (5,134,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (69,873,000)	\$ (69,394,000)	\$ (68,901,000)	\$ (68,393,000)	\$ (67,871,000)	\$ (67,331,000)	\$ (66,776,000)	\$ (66,204,000)	\$ (65,615,000)	\$ (65,009,000)	\$ (64,384,000)	\$ (63,740,000)	\$ (63,077,000)	\$ (62,394,000)	\$ (61,690,000)	\$ (60,966,000)	\$ (60,220,000)	\$ (59,452,000)	\$ (58,660,000)
Total Cumulative Cashflow with Baseline																							
Operating Costs Excluded			\$ -	\$ -	\$ (68,345,000)	\$ (66,292,000)	\$ (64,177,000)	\$ (61,999,000)	\$ (59,757,000)	\$ (57,445,000)	\$ (55,065,000)	\$ (52,614,000)	\$ (50,090,000)	\$ (47,490,000)	\$ (44,811,000)	\$ (42,050,000)	\$ (39,209,000)	\$ (36,281,000)	\$ (33,265,000)	\$ (30,161,000)	\$ (26,963,000)	\$ (23,669,000)	\$ (20,275,000)
Lifecycle Cost Difference with Baseline			\$ -	\$ -	-33890510	-31717020	-29447530	-27081040	-24615550	-22044060	-19367570	-16581080	-13682590	-10667100	-7530610	-4268120	-881630	2637860	6292350	10083840	14019330	18102820	22339310
Total Life Cycle Cost		\$ 57,551,000																					

Table 3a: Hybrid (Baseload Cogen + Excess RNG to market+incentives) under Proposed RFS																							
CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 66,300,277	\$ 68,274,000	\$ -	\$ -	\$ 70,338,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 66,300,277	\$ 68,274,000	\$ -	\$ -	\$ 70,338,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 250,000	\$ 5,598,000	\$ -	\$ -	\$ 265,000	\$ 273,000	\$ 281,000	\$ 290,000	\$ 299,000	\$ 307,000	\$ 317,000	\$ 326,000	\$ 336,000	\$ 346,000	\$ 356,000	\$ 367,000	\$ 378,000	\$ 389,000	\$ 401,000	\$ 413,000	\$ 426,000	\$ 438,000	\$ 452,000
Electricity/NG	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 1,022,253	\$ 22,899,000	\$ -	\$ -	\$ 1,085,000	\$ 1,117,000	\$ 1,151,000	\$ 1,185,000	\$ 1,221,000	\$ 1,257,000	\$ 1,295,000	\$ 1,334,000	\$ 1,374,000	\$ 1,415,000	\$ 1,457,000	\$ 1,501,000	\$ 1,546,000	\$ 1,593,000	\$ 1,640,000	\$ 1,690,000	\$ 1,740,000	\$ 1,793,000	\$ 1,846,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 2,404,035	\$ 53,899,000	\$ -	\$ -	\$ 2,550,000	\$ 2,627,000	\$ 2,706,000	\$ 2,787,000	\$ 2,872,000	\$ 2,956,000	\$ 3,046,000	\$ 3,137,000	\$ 3,231,000	\$ 3,328,000	\$ 3,427,000	\$ 3,530,000	\$ 3,636,000	\$ 3,745,000	\$ 3,857,000	\$ 3,974,000	\$ 4,093,000	\$ 4,216,000	\$ 4,342,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (2,140,332)	\$ (48,663,000)			\$ (2,271,000)	\$ (2,339,000)	\$ (2,409,000)	\$ (2,481,000)	\$ (2,556,000)	\$ (2,632,000)	\$ (2,711,000)	\$ (2,793,000)	\$ (2,876,000)	\$ (2,963,000)	\$ (3,052,000)	\$ (3,143,000)	\$ (3,237,000)	\$ (3,335,000)	\$ (3,435,000)	\$ (3,538,000)	\$ (3,644,000)	\$ (3,753,000)	\$ (3,866,000)
Total Revenues	\$ (3,363,078)	\$ (76,462,000)	\$ -	\$ -	\$ (3,568,000)	\$ (3,675,000)	\$ (3,785,000)	\$ (3,899,000)	\$ (4,016,000)	\$ (4,136,000)	\$ (4,260,000)	\$ (4,388,000)	\$ (4,520,000)	\$ (4,655,000)	\$ (4,795,000)	\$ (4,939,000)	\$ (5,087,000)	\$ (5,240,000)	\$ (5,397,000)	\$ (5,559,000)	\$ (5,725,000)	\$ (5,897,000)	\$ (6,074,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (69,320,000)	\$ (68,272,000)	\$ (67,193,000)	\$ (66,081,000)	\$ (64,937,000)	\$ (63,757,000)	\$ (62,543,000)	\$ (61,292,000)	\$ (60,003,000)	\$ (58,676,000)	\$ (57,308,000)	\$ (55,899,000)	\$ (54,448,000)	\$ (52,953,000)	\$ (51,413,000)	\$ (49,828,000)	\$ (48,196,000)	\$ (46,515,000)	\$ (44,783,000)
Total Cumulative Cashflow with Baseline																							
Operating Costs Excluded			\$ -	\$ -	\$ (67,792,000)	\$ (65,170,000)	\$ (62,469,000)	\$ (59,687,000)	\$ (56,823,000)	\$ (53,871,000)	\$ (50,832,000)	\$ (47,702,000)	\$ (44,478,000)	\$ (41,157,000)	\$ (37,735,000)	\$ (34,209,000)	\$ (30,580,000)	\$ (26,840,000)	\$ (22,988,000)	\$ (19,023,000)	\$ (14,939,000)	\$ (10,732,000)	\$ (6,398,000)
Lifecycle Cost Difference with Baseline			\$ -	\$ -	-33337510	-30595020	-27739530	-24769040	-21681550	-18470060	-15134570	-11669080	-8070590	-4334100	-454610	3572880	7747370	12078860	16569350	21221840	26043330	31039820	36216310
Total Life Cycle Cost		\$ 45,711,000																					

Lifecycle Cost Difference with Baseline			\$ -	\$ -	-9606510	-7433020	-5163530	-2797040	-331550	2239940	4916430	7702920	10601410	13616900	16753390	20015880	23402370	26921860	30576350	34367840	38303330	42386820	46623310
Total Life Cycle Cost		\$ 33,980,000																					

Option 3: Hybrid (Baseload Cogen + Excess RNG to NWN, w/MHP)

CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 78,545,867	\$ 80,884,000	\$ -	\$ -	\$ 83,329,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 78,545,867	\$ 80,884,000	\$ -	\$ -	\$ 83,329,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 250,000	\$ 5,598,000	\$ -	\$ -	\$ 265,000	\$ 273,000	\$ 281,000	\$ 290,000	\$ 299,000	\$ 307,000	\$ 317,000	\$ 326,000	\$ 336,000	\$ 346,000	\$ 356,000	\$ 367,000	\$ 378,000	\$ 389,000	\$ 401,000	\$ 413,000	\$ 426,000	\$ 438,000	\$ 452,000
Electricity/NG	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 852,245	\$ 19,090,000	\$ -	\$ -	\$ 904,000	\$ 931,000	\$ 959,000	\$ 988,000	\$ 1,018,000	\$ 1,048,000	\$ 1,080,000	\$ 1,112,000	\$ 1,145,000	\$ 1,180,000	\$ 1,215,000	\$ 1,252,000	\$ 1,289,000	\$ 1,328,000	\$ 1,368,000	\$ 1,409,000	\$ 1,451,000	\$ 1,494,000	\$ 1,539,000
Chemicals	\$ 227,725	\$ 5,176,000			\$ 242,000	\$ 249,000	\$ 256,000	\$ 264,000	\$ 272,000	\$ 280,000	\$ 288,000	\$ 297,000	\$ 306,000	\$ 315,000	\$ 325,000	\$ 334,000	\$ 344,000	\$ 355,000	\$ 365,000	\$ 376,000	\$ 388,000	\$ 399,000	\$ 411,000
Biosolids Hauling/Disposal	\$ 591,078	\$ 13,240,000	\$ -	\$ -	\$ 627,000	\$ 646,000	\$ 665,000	\$ 685,000	\$ 706,000	\$ 727,000	\$ 749,000	\$ 771,000	\$ 794,000	\$ 818,000	\$ 843,000	\$ 868,000	\$ 894,000	\$ 921,000	\$ 949,000	\$ 977,000	\$ 1,006,000	\$ 1,036,000	\$ 1,068,000
Total Annual Operating Costs	\$ 1,921,047	\$ 43,104,000	\$ -	\$ -	\$ 2,038,000	\$ 2,099,000	\$ 2,161,000	\$ 2,227,000	\$ 2,295,000	\$ 2,362,000	\$ 2,434,000	\$ 2,506,000	\$ 2,581,000	\$ 2,659,000	\$ 2,739,000	\$ 2,821,000	\$ 2,905,000	\$ 2,993,000	\$ 3,083,000	\$ 3,175,000	\$ 3,271,000	\$ 3,367,000	\$ 3,470,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (962,571)	\$ (21,885,000)			\$ (1,021,000)	\$ (1,052,000)	\$ (1,083,000)	\$ (1,116,000)	\$ (1,149,000)	\$ (1,184,000)	\$ (1,219,000)	\$ (1,256,000)	\$ (1,294,000)	\$ (1,332,000)	\$ (1,372,000)	\$ (1,414,000)	\$ (1,456,000)	\$ (1,500,000)	\$ (1,545,000)	\$ (1,591,000)	\$ (1,639,000)	\$ (1,688,000)	\$ (1,739,000)
Total Revenues	\$ (2,185,317)	\$ (49,684,000)	\$ -	\$ -	\$ (2,318,000)	\$ (2,388,000)	\$ (2,460,000)	\$ (2,533,000)	\$ (2,609,000)	\$ (2,688,000)	\$ (2,768,000)	\$ (2,851,000)	\$ (2,937,000)	\$ (3,025,000)	\$ (3,116,000)	\$ (3,209,000)	\$ (3,305,000)	\$ (3,405,000)	\$ (3,507,000)	\$ (3,612,000)	\$ (3,720,000)	\$ (3,832,000)	\$ (3,947,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (83,049,000)	\$ (82,760,000)	\$ (82,461,000)	\$ (82,155,000)	\$ (81,841,000)	\$ (81,515,000)	\$ (81,181,000)	\$ (80,836,000)	\$ (80,480,000)	\$ (80,114,000)	\$ (79,737,000)	\$ (79,349,000)	\$ (78,949,000)	\$ (78,537,000)	\$ (78,113,000)	\$ (77,676,000)	\$ (77,227,000)	\$ (76,762,000)	\$ (76,285,000)
Total Cumulative Cashflow with Baseline Operating Costs Excluded			\$ -	\$ -	\$ (81,521,000)	\$ (79,658,000)	\$ (77,737,000)	\$ (75,761,000)	\$ (73,727,000)	\$ (71,629,000)	\$ (69,470,000)	\$ (67,246,000)	\$ (64,955,000)	\$ (62,595,000)	\$ (60,164,000)	\$ (57,659,000)	\$ (55,081,000)	\$ (52,424,000)	\$ (49,688,000)	\$ (46,871,000)	\$ (43,970,000)	\$ (40,979,000)	\$ (37,900,000)
Lifecycle Cost Difference with Baseline			\$ -	\$ -	-47066510	-45083020	-43007530	-40843040	-38585550	-36228060	-33772570	-31213080	-28547590	-25772100	-22883610	-19877120	-16753630	-13505140	-10130650	-6626160	-2987670	792820	4714310
Total Life Cycle Cost		\$ 74,304,000																					

Option 3b: Hybrid (Baseload Cogen + Excess RNG to NWN)

CAPITAL COSTS	2022 Costs	Present Worth	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total Cost with Standard Additional Project Costs, Contractor Markups, and Location Adjustment Factor Added	\$ 36,981,437	\$ 38,083,000	\$ -	\$ -	\$ 39,234,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Capital Costs	\$ 36,981,437	\$ 38,083,000	\$ -	\$ -	\$ 39,234,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Labor	\$ 250,000	\$ 5,598,000	\$ -	\$ -	\$ 265,000	\$ 273,000	\$ 281,000	\$ 290,000	\$ 299,000	\$ 307,000	\$ 317,000	\$ 326,000	\$ 336,000	\$ 346,000	\$ 356,000	\$ 367,000	\$ 378,000	\$ 389,000	\$ 401,000	\$ 413,000	\$ 426,000	\$ 438,000	\$ 452,000
Electricity/NG	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Maintenance	\$ 1,022,253	\$ 22,899,000	\$ -	\$ -	\$ 1,085,000	\$ 1,117,000	\$ 1,151,000	\$ 1,185,000	\$ 1,221,000	\$ 1,257,000	\$ 1,295,000	\$ 1,334,000	\$ 1,374,000	\$ 1,415,000	\$ 1,457,000	\$ 1,501,000	\$ 1,546,000	\$ 1,593,000	\$ 1,640,000	\$ 1,690,000	\$ 1,740,000	\$ 1,793,000	\$ 1,846,000
Chemicals	\$ 144,577	\$ 3,288,000			\$ 153,000	\$ 158,000	\$ 163,000	\$ 168,000	\$ 173,000	\$ 178,000	\$ 183,000	\$ 189,000	\$ 194,000	\$ 200,000	\$ 206,000	\$ 212,000	\$ 219,000	\$ 225,000	\$ 232,000	\$ 239,000	\$ 246,000	\$ 254,000	\$ 261,000
Biosolids Hauling/Disposal	\$ 987,205	\$ 22,114,000	\$ -	\$ -	\$ 1,047,000	\$ 1,079,000	\$ 1,111,000	\$ 1,144,000	\$ 1,179,000	\$ 1,214,000	\$ 1,251,000	\$ 1,288,000	\$ 1,327,000	\$ 1,367,000	\$ 1,408,000	\$ 1,450,000	\$ 1,493,000	\$ 1,538,000	\$ 1,584,000	\$ 1,632,000	\$ 1,681,000	\$ 1,731,000	\$ 1,783,000
Total Annual Operating Costs	\$ 2,404,035	\$ 53,899,000	\$ -	\$ -	\$ 2,550,000	\$ 2,627,000	\$ 2,706,000	\$ 2,787,000	\$ 2,872,000	\$ 2,956,000	\$ 3,046,000	\$ 3,137,000	\$ 3,231,000	\$ 3,328,000	\$ 3,427,000	\$ 3,530,000	\$ 3,636,000	\$ 3,745,000	\$ 3,857,000	\$ 3,974,000	\$ 4,093,000	\$ 4,216,000	\$ 4,342,000
Annual Revenue (HSW Tipping Fees)	\$ (1,222,746)	\$ (27,799,000)			\$ (1,297,000)	\$ (1,336,000)	\$ (1,376,000)	\$ (1,417,000)	\$ (1,460,000)	\$ (1,504,000)	\$ (1,549,000)	\$ (1,595,000)	\$ (1,643,000)	\$ (1,693,000)	\$ (1,743,000)	\$ (1,796,000)	\$ (1,850,000)	\$ (1,905,000)	\$ (1,962,000)	\$ (2,021,000)	\$ (2,082,000)	\$ (2,144,000)	\$ (2,208,000)
Annual Revenue (Renewable Energy)	\$ (370,220)	\$ (8,418,000)			\$ (393,000)	\$ (405,000)	\$ (417,000)	\$ (429,000)	\$ (442,000)	\$ (455,000)	\$ (469,000)	\$ (483,000)	\$ (498,000)	\$ (512,000)	\$ (528,000)	\$ (544,000)	\$ (560,000)	\$ (577,000)	\$ (594,000)	\$ (612,000)	\$ (630,000)	\$ (649,000)	\$ (669,000)
Total Revenues	\$ (1,592,966)	\$ (36,217,000)	\$ -	\$ -	\$ (1,690,000)	\$ (1,741,000)	\$ (1,793,000)	\$ (1,847,000)	\$ (1,902,000)	\$ (1,959,000)	\$ (2,018,000)	\$ (2,078,000)	\$ (2,141,000)	\$ (2,205,000)	\$ (2,271,000)	\$ (2,339,000)	\$ (2,410,000)	\$ (2,482,000)	\$ (2,556,000)	\$ (2,633,000)	\$ (2,712,000)	\$ (2,793,000)	\$ (2,877,000)
Total Cumulative Cashflow			\$ -	\$ -	\$ (40,094,000)	\$ (40,980,000)	\$ (41,893,000)	\$ (42,833,000)	\$ (43,803,000)	\$ (44,800,000)	\$ (45,828,000)	\$ (46,887,000)	\$ (47,977,000)	\$ (49,100,000)	\$ (50,256,000)	\$ (51,447,000)	\$ (52,673,000)	\$ (53,936,000)	\$ (55,237,000)	\$ (56,578,000)	\$ (57,959,000)	\$ (59,382,000)	\$ (60,847,000)
Total Cumulative Cashflow with Baseline Operating Costs Excluded			\$ -	\$ -	\$ (38,566,000)	\$ (37,878,000)	\$ (37,169,000)	\$ (36,439,000)	\$ (35,689,000)	\$ (34,914,000)	\$ (34,117,000)	\$ (33,297,000)	\$ (32,452,000)	\$ (31,581,000)	\$ (30,683,000)	\$ (29,757,000)	\$ (28,805,000)	\$ (27,823,000)	\$ (26,812,000)	\$ (25,773,000)	\$ (24,702,000)	\$ (23,599,000)	\$ (22,462,000)
Lifecycle Cost Difference with Baseline			\$ -	\$ -	-4111510	-3303020	-2439530	-1521040	-547550	486940	1580430	2735920	3955410	5241900	6597390	8024880	9522370	11095860	12745350	14471840	16280330	18172820	20152310
Total Life Cycle Cost		\$ 55,765,000																					

					Calculate Sellable Power >		Convert Power Generated to Alternative Currency >							Convert Credits to \$ >					Calculate % Offtake													
Alternative		Alternative Currency	Name of Renewable Energy Credit	Seller	Buyer	Power Generated (kWh/Year)	Power Consumed Onsite (kWh/Year)	Sellable Amount (kWh/year)	Units	Scenario	Equivalency Value	Equivalency Value Units	Credits Generated	Credit Units	Scenario	Credits Generated	Credit Unit	Credit Sale Price	Gross \$/Credits Generated	Scenario	Offtake %	\$ to City	\$ to Offtaker									
1	Renewable Electricity																															
Option	Program																															
1a	Commodity Value + OR CFP + EPA RFS																															
a-i	Commodity Value	\$		Gresham	PGE	17,344,800	7,884,000	9,460,800	kWh/year	Low Equivelency Value	0.04	\$/kWh	\$378,432.00	\$	Standard		\$		\$378,432.00			\$378,432.00										
																			High CI Score (-100g CO2e/MJ)	40	\$696,058.86	\$464,039.24										
																			Average of low and high	30	\$812,068.67	\$348,029.43										
																			Low CI Score (25g CO2e/MJ)	20	\$928,078.48	\$232,019.62										
																			High CI Score (-100g CO2e/MJ)	40	\$999,198.30	\$666,132.20										
																			Average of low and high	30	\$1,165,731.35	\$499,599.15										
a-ii	Oregon Clean Fuels Program	CFP Credits	Clean Energy Credit	Gresham	Offtake partner offering Oregon placement	n/a	n/a	9,460,800	kWh/year	High Equivelency Value	659	kWh/CFP Credit	14,356	CFP	High Equivelency Value	14,356	CFP Credit	\$116.00	\$1,665,330.50	Low CI Score (25g CO2e/MJ)	20	\$1,332,264.40	\$333,066.10									
																			Low (Current) Equivelency Value	22.6	kWh/RIN	418,619	eRIN	Low (Current) Equivelency Value	418,619	eRIN	\$1.50	\$627,929.20	Car Manfucaturer Control Market	40	\$376,757.52	\$251,171.68
																												EPA retains	15	\$533,739.82	\$94,189.38	
																												Car Manfucaturer Control Market	40	\$774,065.45	\$516,043.64	
a-iii	EPA RFS eRINs	D5 eRINS	RFS eRINs	Gresham	Offtake partner offering RFS placement	n/a	n/a	9,460,800	kWh/year	Possible High Equivelency Value	11	kWh/RIN	860,073	eRIN	Possible High Equivelency Value	860,073	eRIN	\$1.50	\$1,290,109.09	EPA retains Control	15	\$1,096,592.73	\$193,516.36									
																			Low (Current) Equivelency Value	22.6	kWh/RIN	418,619	eRIN	Low (Current) Equivelency Value	418,619	eRIN	\$2.21	\$925,149.03	Car Manfucaturer Control Market	40	\$555,089.42	\$370,059.61
																												EPA retains	15	\$786,376.67	\$138,772.35	
																												Car Manfucaturer Control Market	30	\$2,251,670.40	\$965,001.60	
a-iii	EPA RFS eRINs under Proposed RFS	D3/D5 eRINS	RFS eRINs	Gresham	Offtake partner offering RFS placement	n/a	n/a	9,460,800	kWh/year	Possible High Equivelency Value	6.5	kWh/RIN	1,455,508	eRIN	Possible High Equivelency Value	1,455,508	eRIN	\$2.21	\$3,216,672.00	EPA retains Control	15	\$2,734,171.20	\$482,500.80									
b	City sell to PGE																															
b-i	Current Net Metering Agreement	kWh		Gresham	PGE	7,884,000	7,884,000	0	kW-hr	Low Equivelency Value	0.08	\$/kWh	\$ -	\$	Standard		\$		\$0.00			\$0.00										
b-ii	Small Generator Interconnection Program	kWh	Avoided Cost Payment	Gresham	PGE	17,344,800	7,884,000	9,460,800	kWh/year	Low Equivelency Value	0.05	\$/kWh	\$ 473,040	\$	Standard		\$		\$473,040.00			\$473,040.00										
c	Third Party																															
c-i	All generation sold to Voluntary Market (or direct 3rd party), PGE wheels	kWh		Gresham	3rd Party	17,344,800	7,884,000	9,460,800	kW-hr		0.055	\$/kWh	\$ 520,344		Standard		\$		PGE Wheeling Charge	20%	\$416,275.20	\$104,068.80										
c-ii	Hybrid -- keep NMA w/PGE, sell new generation to 3rd party	kWh		Gresham	3rd Party/PGE				kW-hr		0.015	\$/kWh																				

					Calculate Sellable Power >		Convert Power Generated to Alternative Currency >							Convert Credits to \$ >				Convert Credits to Dollars >															
Alternative	Alternative Currency	Name of Renewable Energy Credit Program	Seller	Buyer	Power Generated (MMBtu/Year)	Power Consumed Onsite (MMBtu/Year)	Sellable Amount (MMBtu/year)	Units	Scenario	Equivalency Value	Equivalency Value Units	Credits Generated	Credit Units	Scenario	Credits Generated	Credit Unit	Credit Sale Price	Gross \$/Credits Generated	Scenario	Offtake %	\$ to City	\$ to Offtaker											
2	Renewable Natural Gas																																
AlternatiProgram																																	
2a		Commodity Value + OR CFP + EPA RFS																															
a-i		Commodity Value	\$	Gresham	148,690	0	148,690	MMBTU/year	Low Commodity High Commodity	\$2.00 \$/MMBtu	297,379 \$/year	446,069 \$/year	Low Commodity High Commodity	297,379	446,069			\$297,379.18			\$446,068.77												
		CFP Credits																		High CI Score (-100g CO2e/MJ)	40	\$527,745.00	\$351,830.00										
																				Average of low and high	25	\$659,681.25	\$219,893.75										
																				Low Equivelency Value	21.4	MMBTU/CFP Credit	7,550	CFP Credits	Low Equivelency Value	7,550	CFP Credit	\$116.50	\$879,575.00	Low CI Score (25g CO2e/MJ)	15	\$747,638.75	\$131,936.25
																				High CI Score (-100g CO2e/MJ)	40	\$1,372,346.70	\$914,897.80										
																				Average of low and high	25	\$1,715,433.38	\$571,811.13										
a-ii		Oregon Clean Fuels Program	Clean Energy Credit	Gresham	Offtake partner offering Oregon placement	n/a	n/a	148,690	MMBTU/year	High Equivelency Value	8.1	MMBTU/CFP Credit	19,633	CFP Credits	High Equivelency Value	19,633	CFP Credit	\$116.50	\$2,287,244.50	Low CI Score (25g CO2e/MJ)	15	\$1,944,157.83	\$343,086.68										
		D5 RINS																		High Offtake %	20	\$2,069,759.09	\$517,439.77										
																				Average Offtake %	15	\$2,199,119.03	\$388,079.83										
a-iii		EPA RFS RINS	RFS RINS	Gresham	Offtake partner offering RFS placement	n/a	n/a	148,690	MMBTU/year	Average Equivelency Value	11.6	MMBTU/RIN	1,724,799	D5 RINS	Average Equivelency Value	1,724,799	D5 RINS	\$1.50	\$2,587,198.86	Low Offtake %	10	\$2,328,478.97	\$258,719.89										
		D3/D5 RINS																		High Offtake %	20	\$3,054,022.43	\$763,505.61										
																				Average Offtake %	15	\$3,244,898.83	\$572,629.21										
a-iii		EPA RFS RINS under Proposed RFS	RFS RINS	Gresham	Offtake partner offering RFS placement	n/a	n/a	148,690	MMBTU/year	Average Equivelency Value	11.6	MMBTU/RIN	1,724,799	D3/D5 RINS	Average Equivelency Value	1,724,799	D3/D5 RINS	\$2.21	\$3,817,528.04	Low Offtake %	10	\$3,435,775.24	\$381,752.80										

				Power Generated (MMBtu/Year)	Power Consumed Onsite (MMBtu/Year)	Sellable Amount (MMBtu/year)	Units	Scenario	Cost to NWN	Cost to City	\$ NWN will pay for RNG		\$ to City (over 20 years)	Average Annual City Revenue	
2b	City sells to NWN												Pay Units		
Subalter native ID	NWN Proposed Subalternatives Descriptions														
b-i	Gresham funds all (gas cleaning/compression/pipeline/injection/O& M)	MMBTU	Gresham	NWN	148,690	0	148,690	MMBTU	(gas cleaning/compressio n/pipeline/injection/ O&M)	\$0.00	\$6,000,000.00	\$13.00	\$/MMBTU	\$38,659,293.32	\$1,932,964.67
b-ii	NWN funds interconnection; City funds gas cleaning (capital and O&M)	MMBTU	Gresham	NWN	148,690	0	148,690	MMBTU	NWN funds interconnection; City funds gas cleaning (capital and O&M)	\$2,500,000.00	\$3,500,000.00	\$8.00	\$/MMBTU	\$23,790,334.35	\$1,189,516.72
b-iii	NWN funds all	MMBTU	Gresham	NWN	148,690	0	148,690	MMBTU	NWN funds all	\$6,000,000.00	\$0.00	\$5.00	\$/MMBTU	\$14,868,958.97	\$743,447.95

3 Hybrid -- Baseload Existing Cogen + Excess RNG

Alternati Program
~ 800KW baseload existing engines
any excess biogas would be injected into
use the results from Alt 2 to determine if i,

Alternative	Alternative Currency	Name of Renewable Energy Credit Program	Seller	Buyer	Power Generated (MMBtu/Year)	Power Consumed Onsite (MMBtu/Year)	Sellable Amount (MMBtu/year)	Units	Scenario	Cost to NWN	Cost to City	\$ NWN will pay for RNG	Pay Units	\$ to City (over 20 years)	Average Annual City Revenue
3a-i			Gresham	NWN	74,044	0	74,044	MMBTU	Gresham funds all (gas cleaning/compression/pipe line/injection/O&M)	\$0.00	\$6,000,000.00	\$5.00	\$/MMBTU	\$7,404,390.00	\$370,219.50
3a-l (MHP)			Gresham	NWN	74,044	0	74,044	MMBTU	Gresham funds all (gas cleaning/compression/pipe line/injection/O&M)	\$0.00	\$6,000,000.00	\$13.00	\$/MMBTU	\$19,251,414.00	\$962,570.70

Alternative	Alternative Currency	Name of Renewable Energy Credit Program	Seller	Buyer	Calculate Sellable Power >		Convert Power Generated to Alternative Currency >							Convert Credits to \$ >					Convert Credits to Dollars >			
					Power Generated (MMBtu/Year)	Power Consumed Onsite (MMBtu/Year)	Sellable Amount (MMBtu/year)	Units	Scenario	Equivalency Value	Equivalency Value Units	Credits Generated	Credit Units	Scenario	Credits Generated	Credit Unit	Credit Sale Price	Gross \$/Credits Generated	Scenario	Offtake %	\$ to City	\$ to Offtaker
a-i	Commodity Value	\$	Gresham		74,044	0	74,044	MMBTU/year	Low Commodity Value	\$2.00	\$/MMBtu	148,088	\$/year	Low Commodity Value				148,088			\$148,087.80	
									High Commodity Value	\$3.00	\$/MMBtu	222,132	\$/year	High Commodity Value				222,132			\$222,131.70	
a-ii	Oregon Clean Fuels Program	CFP Credits	Gresham	Offtake partner offering Oregon placement	n/a	n/a	74,044	MMBTU/year	Low Equivelency Value	21.4	MMBTU/CFP Credit	3,460	CFP Credits	Low Equivelency Value	3,460	CFP Credit	\$116.50	\$403,089.46	High CI Score (-100g CO2e/MJ)	40	\$241,853.67	\$161,235.78
									High Equivelency Value	8.1	MMBTU/CFP Credit	9,141	CFP Credits	High Equivelency Value	9,141	CFP Credit	\$116.50	\$1,064,952.39	Average of low	25	\$302,317.09	\$100,772.36
									Average Equivelency Value	11.6	MMBTU/RIN	858,909	D5 RINS	Average Equivelency Value	858,909	D5 RINS	\$1.50	\$1,288,363.86	Low CI Score (25g	15	\$342,626.04	\$60,463.42
																			High CI Score (-100g CO2e/MJ)	40	\$638,971.43	\$425,980.96
a-iii	EPA RFS RINS	D5 RINS	Gresham	Offtake partner offering RFS placement	n/a	n/a	74,044	MMBTU/year	Average Equivelency Value	11.6	MMBTU/RIN	858,909	D5 RINS	Average Equivelency Value	858,909	D5 RINS	\$1.50	\$1,288,363.86	Average of low	25	\$798,714.29	\$266,238.10
																			Low CI Score (25g	15	\$905,209.53	\$159,742.86
a-iiii	EPA RFS RINS under Proposed RFS	D3/D5 RINS	Gresham	Offtake partner offering RFS placement	n/a	n/a	74,044	MMBTU/year	Average Equivelency Value	11.6	MMBTU/RIN	858,909	D5 RINS	Average Equivelency Value	858,909	D3/D5 RINS	\$2.21	\$1,901,038.70	High Offtake %	20	\$1,520,830.96	\$380,207.74
																			Average Offtake	15	\$1,615,882.90	\$285,155.81
																			Low Offtake %	10	\$1,710,934.83	\$190,103.87

Appendix C. Capital Cost and Annual Operating Costs

		Renewable Electricity Options				
Item		Unit	Unit Cost	Qty	Notes	Cost
HSW Receiving						
Equipment Power Demand						
	All Equipment	\$/kWh	0.071	0	Assume 15 hp total	Included in NPV
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$1,026,168		\$30,785
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
Product Haul Cost/Revenue						
	Tipping Fee for Current FOG	\$/gal	-0.09	4,231,936		-\$380,874
	Tipping Fee for Food Waste	\$/gal	-0.06	6,714,628		-\$402,878
	Tipping Fee for Addt'l FOG	\$/gal	-0.09	4,877,714		-\$438,994
ANNUAL COST						-\$1,191,961
Anaerobic Digester System						
Equipment Power Demand						
	Mixing System	\$/kWh	0.071	0	10 HP and 0.75 PF	Included in NPV
	Solids circulation chopper pumps	\$/kWh	0.071	0	40 HP and 0.75 PF	Included in NPV
	Hot water circulation pumps	\$/kWh	0.071	0	20 HP and 0.75 PF	Included in NPV
	Digested solids transfer pumps	\$/kWh	0.071	0	30 HP and 0.75 PF	Included in NPV
	Building Odor Control	W-hr/scf	0.0195	0		Included in NPV
Natural Gas Demand						
	Natural Gas Cost	\$/MMBTU LHV	4.4	0.00	-	Included in NPV
Building O&M						
	Building Lighting	Watts/sf	1.0	2,500		Included in NPV
	Building Ventilation	Watts/sf	3.0	2,500		Included in NPV
Operation Labor						
	Digesters	\$/yr-FTE	\$100,000	2	FTEs	\$200,000
	Biosolids Marketing	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$3,430,600		\$102,918
	Facilities Maintenance	% capital/yr	1%	\$4,390,400		\$43,904
ANNUAL COST						\$346,822
Dewatering, Cake Conveyance, and Cake Storage						
Equipment Power Demand						
	Dewatering Power Demand	\$/kWh	0.071	0	Assume 30 hp	Included in NPV
Polymer Demand						
	Dewatering Polymer	\$/lb neat	1.63	88,698		\$144,577
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$0		\$0.00
	Facilities Maintenance	% capital/yr	1%	\$619,412		\$6,194
ANNUAL COST						\$150,771
Gas Conditioning						
Equipment Power Demand						
	Gas Conditioning	\$/kWh	0.071	0	0.7 kW-hr/100scf	Included in NPV
Operation Labor						
	Gas Conditioning	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	Annual Operating Cost for H2S, Moisture, siloxane reduction (250 scfm)	\$/year	\$120,000	2		\$240,000
	Annual Operating Cost for RNG treatment (250 scfm)	\$/year	\$300,000	0		\$0
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
Product Haul Cost/Revenue						
	Value of RNG	0	-\$2.50	0	-	\$0
ANNUAL COST						\$240,000
CHP						
Operation Labor						
	CHP	\$/yr-FTE	\$100,000	1.0	FTEs	\$100,000
Maintenance						
	Annual Operating Cost for 2x 400 kWe engines	\$/year	\$300,000	2		\$600,000
	CI Score Verification					\$0
ANNUAL COST						\$700,000
Hauling From Gresham Plant to Land App						
Product Haul Cost/Revenue						
	Class B Cake Hauling					\$987,205
ANNUAL COST						\$987,205
Annual Labor Cost						\$300,000
Annual Maintenance Cost						\$1,023,801
Annual Hauling Cost						\$987,205
Annual Chemical Cost						\$144,577
Annual Tipping Fee Revenue						-\$1,222,746
Annual Revenue from Renewable Energy						Included in NPV
Average Annual Cost						\$ 1,232,837

		RE + MHP + TAD				
Item		Unit	Unit Cost	Qty	Notes	Cost
HSW Receiving						
Equipment Power Demand						
	All Equipment	\$/kWh	0.071	65,700	Assume 15 hp total	Included in NPV
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$1,026,168		\$30,785
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
Product Haul Cost/Revenue						
	Tipping Fee for Current FOG	\$/gal	-0.09	4,231,936		-\$380,874
	Tipping Fee for Food Waste	\$/gal	-0.06	6,714,628		-\$402,878
	Tipping Fee for Addt'l FOG	\$/gal	-0.09	4,877,714		-\$438,994
ANNUAL COST						-\$1,191,961
Anaerobic Digester System						
Equipment Power Demand						
	Mixing System	\$/kWh	0.071	24,506	10 HP and 0.75 PF	Included in NPV
	Solids circulation chopper pumps	\$/kWh	0.071	196,049	40 HP and 0.75 PF	Included in NPV
	Hot water circulation pumps	\$/kWh	0.071	98,024	20 HP and 0.75 PF	Included in NPV
	Digested solids transfer pumps	\$/kWh	0.071	147,037	30 HP and 0.75 PF	Included in NPV
	Building Odor Control	W-hr/scf	0.0195	9,609		Included in NPV
Natural Gas Demand						
	Natural Gas Cost	\$/MMBTU LHV	4.4	18085.02	-	Included in NPV
Building O&M						
	Building Lighting	Watts/sf	1.0	2,500		Included in NPV
	Building Ventilation	Watts/sf	3.0	2,500		Included in NPV
Operation Labor						
	Digesters	\$/yr-FTE	\$100,000	2	FTEs	\$200,000
	Biosolids Marketing	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$7,545,275		\$226,358
	Facilities Maintenance	% capital/yr	1%	\$4,390,400		\$43,904
ANNUAL COST						\$470,262
Dewatering, Cake Conveyance, and Cake Storage						
Equipment Power Demand						
	Dewatering Power Demand	\$/kWh	0.071	73,518	Assume 30 hp	Included in NPV
Polymer Demand						
	Dewatering Polymer	\$/lb neat	1.63	88,698		\$144,577
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$0		\$0.00
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
ANNUAL COST						\$144,577
Gas Conditioning						
Equipment Power Demand						
	Gas Conditioning	\$/kWh	0.071	275,940	0.7 kW-hr/100scf	Included in NPV
Operation Labor						
	Gas Conditioning	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	Annual Operating Cost for H2S, Moisture, siloxane reduction (250 scfm)	\$/year	\$120,000	2		\$240,000
	Annual Operating Cost for RNG treatment (250 scfm)	\$/year	\$300,000	0		\$0
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
Product Haul Cost/Revenue						
	Value of RNG	0	-\$2.50	0	-	\$0
ANNUAL COST						\$240,000
CHP						
Operation Labor						
	CHP	\$/yr-FTE	\$100,000	1.0	FTEs	\$100,000
Maintenance						
	Annual Operating Cost for 2x 400 kWe engines	\$/year	\$300,000	2		\$600,000
	CI Score Verification					\$0
ANNUAL COST						\$700,000
Hauling From Gresham Plant to Land App						
Product Haul Cost/Revenue						
	Class A Cake Hauling					\$591,078
ANNUAL COST						\$591,078
Annual Labor Cost						\$300,000
Annual Maintenance Cost						\$1,141,047
Annual Hauling Cost						\$591,078
Annual Chemical Cost						\$144,577
Annual Tipping Fee Revenue						-\$1,222,746
Annual Revenue from Renewable Energy						Included in NPV
Average Annual Cost						\$ 953,956

		RE + MHP + MAD				
		Item	Unit	Unit Cost	Qty	Notes
HSW Receiving						
Equipment Power Demand						
	All Equipment	\$/kWh	0.071	65,700	Assume 15 hp total	Included in NPV
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$1,026,168		\$30,785
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
Product Haul Cost/Revenue						
	Tipping Fee for Current FOG	\$/gal	-0.09	4,231,936		-\$380,874
	Tipping Fee for Food Waste	\$/gal	-0.06	6,714,628		-\$402,878
	Tipping Fee for Addt'l FOG	\$/gal	-0.09	4,877,714		-\$438,994
ANNUAL COST						-\$1,191,961
Anaerobic Digester System						
Equipment Power Demand						
	Mixing System	\$/kWh	0.071	24,506	10 HP and 0.75 PF	Included in NPV
	Solids circulation chopper pumps	\$/kWh	0.071	196,049	40 HP and 0.75 PF	Included in NPV
	Hot water circulation pumps	\$/kWh	0.071	98,024	20 HP and 0.75 PF	Included in NPV
	Digested solids transfer pumps	\$/kWh	0.071	147,037	30 HP and 0.75 PF	Included in NPV
	Building Odor Control	W-hr/scf	0.0195	9,609		Included in NPV
Natural Gas Demand						
	Natural Gas Cost	\$/MMBTU LHV	4.4	18085.02	-	Included in NPV
Building O&M						
	Building Lighting	Watts/sf	1.0	2,500		Included in NPV
	Building Ventilation	Watts/sf	3.0	2,500		Included in NPV
Operation Labor						
	Digesters	\$/yr-FTE	\$100,000	2	FTEs	\$200,000
	Biosolids Marketing	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$5,666,232		\$169,987
	Facilities Maintenance	% capital/yr	1%	\$4,390,400		\$43,904
ANNUAL COST						\$413,891
Dewatering, Cake Conveyance, and Cake Storage						
Equipment Power Demand						
	Dewatering Power Demand	\$/kWh	0.071	73,518	Assume 30 hp	Included in NPV
Polymer Demand						
	Dewatering Polymer	\$/lb neat	1.63	88,698		\$144,577
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$0		\$0.00
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
ANNUAL COST						\$144,577
Gas Conditioning						
Equipment Power Demand						
	Gas Conditioning	\$/kWh	0.071	275,940	0.7 kW-hr/100scf	Included in NPV
Operation Labor						
	Gas Conditioning	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	Annual Operating Cost for H2S, Moisture, siloxane reduction (250 scfm)	\$/year	\$120,000	2		\$240,000
	Annual Operating Cost for RNG treatment (250 scfm)	\$/year	\$300,000	0		\$0
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
Product Haul Cost/Revenue						
	Value of RNG	0	-\$2.50	0	-	\$0
ANNUAL COST						\$240,000
CHP						
Operation Labor						
	CHP	\$/yr-FTE	\$100,000	1.0	FTEs	\$100,000
Maintenance						
	Annual Operating Cost for 2x 400 kWe engines	\$/year	\$300,000	2		\$600,000
	CI Score Verification					\$0
ANNUAL COST						\$700,000
Hauling From Gresham Plant to Land App						
Product Haul Cost/Revenue						
	Class A Cake Hauling					\$591,078
ANNUAL COST						\$591,078
Annual Labor Cost						\$300,000
Annual Maintenance Cost						\$1,084,676
Annual Hauling Cost						\$591,078
Annual Chemical Cost						\$144,577
Annual Tipping Fee Revenue						-\$1,222,746
Annual Revenue from Renewable Energy						See Revenue Analysis
Average Annual Cost						\$ 897,585

	Renewable Natural Gas Options					
	Item	Unit	Unit Cost	Qty	Notes	Cost
HSW Receiving	203					
Equipment Power Demand						
	All Equipment	\$/kWh	0.071	131,400	Assume 15 hp total	Included in NPV
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$932,880		\$27,986
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
Product Haul Cost/Revenue						
	Tipping Fee for Current FOG	\$/gal	-0.09	4,231,936		-\$380,874
	Tipping Fee for Food Waste	\$/gal	-0.06	6,714,628		-\$402,878
	Tipping Fee for Addt'l FOG	\$/gal	-0.09	4,877,714		-\$438,994
ANNUAL COST						-\$1,194,760
Anaerobic Digester System						
Equipment Power Demand						
	Mixing System	\$/kWh	0.071	49,012	10 HP and 0.75 PF	Included in NPV
	Solids circulation chopper pumps	\$/kWh	0.071	392,098	40 HP and 0.75 PF	Included in NPV
	Hot water circulation pumps	\$/kWh	0.071	196,049	20 HP and 0.75 PF	Included in NPV
	Digested solids transfer pumps	\$/kWh	0.071	294,073	30 HP and 0.75 PF	Included in NPV
	Building Odor Control	W-hr/scf	0.0195	19,217		Included in NPV
Natural Gas Demand						
	Natural Gas Cost	\$/MMBTU LHV	4.4	48251.83	-	Included in NPV
Building O&M						
	Building Lighting	Watts/sf	1.0	2,500		Included in NPV
	Building Ventilation	Watts/sf	3.0	2,500		Included in NPV
Operation Labor						
	Digesters	\$/yr-FTE	\$100,000	2	FTEs	\$200,000
	Biosolids Marketing	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$3,430,600		\$102,918
	Facilities Maintenance	% capital/yr	1%	\$4,390,400		\$43,904
ANNUAL COST						\$346,822
Dewatering, Cake Conveyance, and Cake Storage						
Equipment Power Demand						
	Dewatering Power Demand	\$/kWh	0.071	147,037	Assume 30 hp	Included in NPV
Polymer Demand						
	Dewatering Polymer	\$/lb neat	1.63	88,698		\$144,577
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$0		\$0.00
	Facilities Maintenance	% capital/yr	1%	\$619,412		\$6,194
ANNUAL COST						\$150,771
Gas Conditioning						
Equipment Power Demand						
	Gas Conditioning	\$/kWh	0.071	551,880	0.7 kW-hr/100scf	Included in NPV
Operation Labor						
	Gas Conditioning	\$/yr-FTE	\$100,000	1	FTEs	\$100,000
Maintenance						
	Annual Operating Cost for H2S, Moisture, siloxane reduction (250 scfm)	\$/year	\$120,000	2		\$240,000
	Annual Operating Cost for RNG treatment (250 scfm)	\$/year	\$300,000	2		\$600,000
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
Product Haul Cost/Revenue						
	Value of RNG	0	-\$2.50	0	-	\$0
ANNUAL COST						\$940,000
CHP						
Operation Labor						
	CHP	\$/yr-FTE	\$100,000	0.0	FTEs	\$0
Maintenance						
	Annual Operating Cost for 2x 400 kWe engines	\$/year	\$300,000	0		\$0
	CI Score Verification					\$0
ANNUAL COST						\$0
Hauling From Gresham Plant to Land App						
Product Haul Cost/Revenue						
	Class B Cake Hauling					\$987,205
ANNUAL COST						\$987,205
Annual Labor Cost						\$300,000
Annual Maintenance Cost						\$1,021,003
Annual Hauling Cost						\$987,205
Annual Chemical Cost						\$144,577
Annual Tipping Fee Revenue						-\$1,222,746
Annual Revenue from Renewable Energy						Included in NPV
Average Annual Cost					\$	1,230,038

		Hybrid Options					
		Item	Unit	Unit Cost	Qty	Notes	Cost
HSW Receiving							
Equipment Power Demand							
	All Equipment	\$/kWh	0.071	65,700	Assume 15 hp total	Included in NPV	
Operation Labor							
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0	
Maintenance							
	New Equipment Maintenance	% capital/yr	3%	\$1,026,168			\$30,785
	Facilities Maintenance	% capital/yr	1%	\$0			\$0
Product Haul Cost/Revenue							
	Tipping Fee for Current FOG	\$/gal	-0.09	4,231,936			-\$380,874
	Tipping Fee for Food Waste	\$/gal	-0.06	6,714,628			-\$402,878
	Tipping Fee for Addt'l FOG	\$/gal	-0.09	4,877,714			-\$438,994
ANNUAL COST							-\$1,191,961
Anaerobic Digester System							
Equipment Power Demand							
	Mixing System	\$/kWh	0.071	24,506	10 HP and 0.75 PF	Included in NPV	
	Solids circulation chopper pumps	\$/kWh	0.071	196,049	40 HP and 0.75 PF	Included in NPV	
	Hot water circulation pumps	\$/kWh	0.071	98,024	20 HP and 0.75 PF	Included in NPV	
	Digested solids transfer pumps	\$/kWh	0.071	147,037	30 HP and 0.75 PF	Included in NPV	
	Building Odor Control	W-hr/scf	0.0195	9,609		Included in NPV	
Natural Gas Demand							
	Natural Gas Cost	\$/MMBTU LHV	4.4	18085.02	-	Included in NPV	
Building O&M							
	Building Lighting	Watts/sf	1.0	2,500		Included in NPV	
	Building Ventilation	Watts/sf	3.0	2,500		Included in NPV	
Operation Labor							
	Digesters	\$/yr-FTE	\$100,000	2	FTEs	\$200,000	
	Biosolids Marketing	\$/yr-FTE	\$100,000	0	FTEs	\$0	
Maintenance							
	New Equipment Maintenance	% capital/yr	3%	\$3,430,600			\$102,918
	Facilities Maintenance	% capital/yr	1%	\$4,390,400			\$43,904
ANNUAL COST							\$346,822
Dewatering, Cake Conveyance, and Cake Storage							
Equipment Power Demand							
	Dewatering Power Demand	\$/kWh	0.071	73,518	Assume 30 hp	Included in NPV	
Polymer Demand							
	Dewatering Polymer	\$/lb neat	1.63	88,698			\$144,577
Operation Labor							
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0	
Maintenance							
	New Equipment Maintenance	% capital/yr	3%	\$0			\$0.00
	Facilities Maintenance	% capital/yr	1%	\$464,559			\$4,646
ANNUAL COST							\$149,223
Gas Conditioning							
Equipment Power Demand							
	Gas Conditioning	\$/kWh	0.071	275,940	0.7 kW-hr/100scf	Included in NPV	
Operation Labor							
	Gas Conditioning	\$/yr-FTE	\$100,000	0.5	FTEs	\$50,000	
Maintenance							
	Annual Operating Cost for H2S, Moisture, siloxane reduction (250 scfm)	\$/year	\$120,000	2			\$240,000
	Annual Operating Cost for RNG treatment (250 scfm)	\$/year	\$300,000	1			\$300,000
	Facilities Maintenance	% capital/yr	1%	\$0			\$0
Product Haul Cost/Revenue							
	Value of RNG	0	-\$2.50	0	-		\$0
ANNUAL COST							\$590,000
CHP							
Operation Labor							
	CHP	\$/yr-FTE	\$100,000	0.0	FTEs	\$0	
Maintenance							
	Annual Operating Cost for 2x 400 kWe engines	\$/year	\$300,000	1			\$300,000
	CI Score Verification						\$0
ANNUAL COST							\$300,000
Hauling From Gresham Plant to Land App							
Product Haul Cost/Revenue							
	Class B Cake Hauling						\$987,205
ANNUAL COST							\$987,205
Annual Labor Cost							\$250,000
Annual Maintenance Cost							\$1,022,253
Annual Hauling Cost							\$987,205
Annual Chemical Cost							\$144,577
Annual Tipping Fee Revenue							-\$1,222,746
Annual Revenue from Renewable Energy							Included in NPV
Average Annual Cost							\$ 1,181,289

		Hybrid Option + MHP					
		Item	Unit	Unit Cost	Qty	Notes	Cost
HSW Receiving							
Equipment Power Demand							
	All Equipment	\$/kWh	0.071	65,700	Assume 15 hp total	Included in NPV	
Operation Labor							
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0	
Maintenance							
	New Equipment Maintenance	% capital/yr	3%	\$1,026,168			\$30,785
	Facilities Maintenance	% capital/yr	1%	\$0			\$0
Product Haul Cost/Revenue							
	Tipping Fee for Current FOG	\$/gal	-0.09	4,231,936			-\$380,874
	Tipping Fee for Food Waste	\$/gal	-0.06	6,714,628			-\$402,878
	Tipping Fee for Addt'l FOG	\$/gal	-0.09	4,877,714			-\$438,994
ANNUAL COST							-\$1,191,961
Anaerobic Digester System							
Equipment Power Demand							
	Mixing System	\$/kWh	0.071	24,506	10 HP and 0.75 PF	Included in NPV	
	Solids circulation chopper pumps	\$/kWh	0.071	196,049	40 HP and 0.75 PF	Included in NPV	
	Hot water circulation pumps	\$/kWh	0.071	98,024	20 HP and 0.75 PF	Included in NPV	
	Digested solids transfer pumps	\$/kWh	0.071	147,037	30 HP and 0.75 PF	Included in NPV	
	Building Odor Control	W-hr/scf	0.0195	9,609		Included in NPV	
Natural Gas Demand							
	Natural Gas Cost	\$/MMBTU LHV	4.4	18085.02	-	Included in NPV	
Building O&M							
	Building Lighting	Watts/sf	1.0	2,500		Included in NPV	
	Building Ventilation	Watts/sf	3.0	2,500		Included in NPV	
Operation Labor							
	Digesters	\$/yr-FTE	\$100,000	3	FTEs	\$300,000	
	Biosolids Marketing	\$/yr-FTE	\$100,000	0	FTEs	\$0	
Maintenance							
	New Equipment Maintenance	% capital/yr	3%	\$7,763,675			\$232,910
	Facilities Maintenance	% capital/yr	1%	\$4,390,400			\$43,904
ANNUAL COST							\$576,814
Dewatering, Cake Conveyance, and Cake Storage							
Equipment Power Demand							
	Dewatering Power Demand	\$/kWh	0.071	73,518	Assume 30 hp	Included in NPV	
Polymer Demand							
	Dewatering Polymer	\$/lb neat	1.63	139,708			\$227,725
Operation Labor							
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0	
Maintenance							
	New Equipment Maintenance	% capital/yr	3%	\$0			\$0.00
	Facilities Maintenance	% capital/yr	1%	\$464,559			\$4,646
ANNUAL COST							\$232,370
Gas Conditioning							
Equipment Power Demand							
	Gas Conditioning	\$/kWh	0.071	275,940	0.7 kW-hr/100scf	Included in NPV	
Operation Labor							
	Gas Conditioning	\$/yr-FTE	\$100,000	0.5	FTEs	\$50,000	
Maintenance							
	Annual Operating Cost for H2S, Moisture, siloxane reduction (250 scfm)	\$/year	\$120,000	2			\$240,000
	Annual Operating Cost for RNG treatment (250 scfm)	\$/year	\$300,000	1			\$300,000
	Facilities Maintenance	% capital/yr	1%	\$0			\$0
Product Haul Cost/Revenue							
	Value of RNG	0	-\$2.50	0	-		\$0
ANNUAL COST							\$590,000
CHP							
Operation Labor							
	CHP	\$/yr-FTE	\$100,000	0.5	FTEs	\$50,000	
Maintenance							
	Annual Operating Cost for 2x 400 kWe engines	\$/year	\$300,000	1			\$300,000
	CI Score Verification						\$0
ANNUAL COST							\$350,000
Hauling From Gresham Plant to Land App							
Product Haul Cost/Revenue							
	Class B Cake Hauling						\$591,078
ANNUAL COST							\$591,078
Annual Labor Cost							\$400,000
Annual Maintenance Cost							\$852,245
Annual Hauling Cost							\$591,078
Annual Chemical Cost							\$227,725
Annual Tipping Fee Revenue							-\$1,222,746
Annual Revenue from Renewable Energy							Included in NPV
Average Annual Cost							\$ 1,148,301

	Baseline (1 new MAD)					
	Item	Unit	Unit Cost	Qty	Notes	Cost
HSW Receiving						
Equipment Power Demand						
	All Equipment	\$/kWh	0.071	0	Assume 15 hp total	Included in NPV
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$713,856		\$21,416
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
Product Haul Cost/Revenue						
	Tipping Fee for Current FOG	\$/gal	-0.09	4,231,936		-\$380,874
	Tipping Fee for Food Waste	\$/gal	-0.06	0		\$0
	Tipping Fee for Addt'l FOG	\$/gal	-0.09	0		\$0
ANNUAL COST						-\$359,459
Anaerobic Digester System						
Equipment Power Demand						
	Mixing System	\$/kWh	0.071	0	10 HP and 0.75 PF	Included in NPV
	Solids circulation chopper pumps	\$/kWh	0.071	0	40 HP and 0.75 PF	Included in NPV
	Hot water circulation pumps	\$/kWh	0.071	0	20 HP and 0.75 PF	Included in NPV
	Digested solids transfer pumps	\$/kWh	0.071	0	30 HP and 0.75 PF	Included in NPV
	Building Odor Control	W-hr/scf	0.0195	0		Included in NPV
Natural Gas Demand						
	Natural Gas Cost	\$/MMBTU LHV	4.4	0.00	-	Included in NPV
Building O&M						
	Building Lighting	Watts/sf	1.0	2,500		Included in NPV
	Building Ventilation	Watts/sf	3.0	2,500		Included in NPV
Operation Labor						
	Digesters	\$/yr-FTE	\$100,000	1	FTEs	\$100,000
	Biosolids Marketing	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$3,391,600		\$101,748
	Facilities Maintenance	% capital/yr	5%	\$1,121,875		\$56,094
ANNUAL COST						\$257,842
Dewatering, Cake Conveyance, and Cake Storage						
Equipment Power Demand						
	Dewatering Power Demand	\$/kWh	0.071	0	Assume 30 hp	Included in NPV
Polymer Demand						
	Dewatering Polymer	\$/lb neat	1.63	67,925		\$110,718
Operation Labor						
	All Equipment	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	New Equipment Maintenance	% capital/yr	3%	\$0		\$0.00
	Facilities Maintenance	% capital/yr	1%	\$0		\$0
ANNUAL COST						\$110,718
Gas Conditioning						
Equipment Power Demand						
	Gas Conditioning	\$/kWh	0.071	0	0.7 kW-hr/100scf	Included in NPV
Operation Labor						
	Gas Conditioning	\$/yr-FTE	\$100,000	0	FTEs	\$0
Maintenance						
	Annual Operating Cost for H2S, Moisture, siloxane reduction (250 scfm)	\$/year	\$120,000	1		\$120,000
	Annual Operating Cost for RNG treatment (250 scfm)	\$/year	\$300,000	0		\$0
	Facilities Maintenance	% capital/yr	1%	\$25,084		\$0
Product Haul Cost/Revenue						
	Value of RNG	0	-\$2.50	0	-	\$0
ANNUAL COST						\$120,000
CHP						
Operation Labor						
	CHP	\$/yr-FTE	\$100,000	0.0	FTEs	\$0
Maintenance						
	Annual Operating Cost for 2x 400 kWe engines	\$/year	\$300,000	1		\$300,000
	CI Score Verification					\$0
ANNUAL COST						\$300,000
Hauling From Gresham Plant to Land App						
Product Haul Cost/Revenue						
	Class B Cake Hauling					\$1,011,569
ANNUAL COST						\$1,011,569
Annual Labor Cost						\$100,000
Annual Maintenance Cost						\$599,257
Annual Hauling Cost						\$1,011,569
Annual Chemical Cost						\$110,718
Annual Tipping Fee Revenue						-\$380,874
Annual Revenue from Renewable Energy						Included in NPV
Average Annual Cost						\$ 1,440,670

Options 1A/1B/1C: Renewable Electricity						
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
FOG and Food Waste Receiving Facility - New and Rehab Existing						
Demolition						
	Demolition Excluded					
Equipment Cost						
	Receiving Station Rock Trap	\$/each	\$10,000	0	1.6	\$0
	Receiving Station Grinder	\$/each	\$80,000	0	1.6	\$0
	Receiving Station Storage Tank (2xFW, 1x FOG)	\$/each	\$39,000	3	1.6	\$182,520
	Receiving Station Unloading Pump	\$/each	\$70,000	2	1.6	\$218,400
	Receiving Station FW Recirculation Pump	\$/each	\$20,000	2	1.6	\$62,400
	Receiving Station Mixer	\$/each	\$116,000	0	1.6	\$0
	Receiving Station Heat Exchanger	\$/each	\$100,000	0	1.6	\$0
	Receiving Station FW Feed Pump	\$/each	\$30,000	2	1.6	\$93,600
	Receiving Station Hot Water Pressure Washer	\$/each	\$16,000	1	1.6	\$24,960
	Receiving Station Odor Control System	\$/each	\$225,000	1	1.6	\$351,000
	Equipment Subtotal					\$932,880
Existing FOG System Rehab (Allowance)		%	10.0%	1	1	\$93,288
Equipment Subtotal						\$1,026,168
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$1,026,168
Sitework	Sitework	%	5.0%			\$51,308
	Direct Cost Subtotal					\$1,077,476
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,077,476
Contractor Markup	Contractor Markup	%	37.4%			\$402,797
	Marked Up Subtotal					\$1,480,273
	Contingency	%	30.0%			\$444,082
	Contingent Subtotal					\$1,924,356
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$96,218
	Construction Cost Subtotal					\$2,020,573
Project Delivery						
	Engineering/Administration/Legal	%	24.0%			\$484,938
	Project Delivery Cost Subtotal					\$2,505,511
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$350,772
CAPITAL COST						\$2,856,282

Anaerobic Digester System - Convert Existing Tanks

Demolition						
	Demolition Included Below					
Equipment Cost						
	Convert Existing Tanks to Thermophilic					
	Digester Tank	\$/gal	\$2.22	0	1.6	\$0
	Mixing System	\$/each	\$100,000	0	1.6	\$0
	Mixing System -LMM Rehab	\$/each	\$292,000	1	1.6	\$467,200
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	0	1.6	\$0
	Solids Recirculation Pumps	\$/each	\$25,000	0	1.6	\$0
	Hot Water Recirculation Pumps	\$/each	\$10,000	0	1.6	\$0
	Digester Fixed Cover Replacement	\$/each	\$1,226,000	2	1.6	\$3,923,200
	Digested Solids Transfer Pumps	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$4,390,400
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$4,390,400
Sitework	Sitework	%	0%			\$0
	Demolition	%	2.0%			\$87,808
	Direct Cost Subtotal					\$4,478,208
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$4,478,208
Contractor Markup	Contractor Markup	%	37.4%			\$1,674,105
	Marked Up Subtotal					\$6,152,313
	Contingency	%	30.0%			\$1,845,694
	Contingent Subtotal					\$7,998,007
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$399,900
	Construction Cost Subtotal					\$8,397,908
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,015,498
	Project Delivery Cost Subtotal					\$10,413,406
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,457,877
CAPITAL COST						\$11,871,282

Anaerobic Digester System - New Tank

Demolition						
	Demolition Excluded					
Equipment Cost						
	Build New Thermophilic Tank					
	Digester Tank	\$/gal	\$2.44	1000000	1.0	\$2,440,000
	Mixing System	\$/each	\$405,000	1	1.6	\$631,800
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	1	1.6	\$109,200
	Solids Recirculation Pumps	\$/each	\$25,000	2	1.6	\$78,000
	Hot Water Recirculation Pumps	\$/each	\$10,000	2	1.6	\$31,200

	Options 1A/1B/1C: Renewable Electricity					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Digested Solids Transfer Pumps	\$/each	\$45,000	2	1.6	\$140,400
	Equipment Subtotal					\$3,430,600
Building						
	Building	\$/sf	\$400	2,500	1.0	\$1,000,000
	Odor Control	\$/scfm	\$65	1,875	1.0	\$121,875
	Buildings Subtotal					\$1,121,875
	System Subtotal					\$4,552,475
Sitework	Sitework	%	43.0%			\$1,957,564
	Direct Cost Subtotal					\$6,510,039
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$6,510,039
Contractor Markup	Contractor Markup	%	37.4%			\$2,433,673
	Marked Up Subtotal					\$8,943,712
	Contingency	%	30.0%			\$2,683,114
	Contingent Subtotal					\$11,626,825
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$581,341
	Construction Cost Subtotal					\$12,208,167
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,929,960
	Project Delivery Cost Subtotal					\$15,138,127
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$2,119,338
CAPITAL COST						\$17,257,464

Dewatering, Cake Conveyance, and Cake Storage

Demolition						
	Demolition Excluded					
Equipment Cost						
	Cake Storage	\$/cf	3.34	118,800	1.6	\$619,412
	Equipment Subtotal					\$619,412
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$619,412
Sitework	Sitework	%	20.0%			\$123,882
	Direct Cost Subtotal					\$743,294
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$743,294
Contractor Markup	Contractor Markup	%	37.4%			\$277,868
	Marked Up Subtotal					\$1,021,163
	Contingency	%	30.0%			\$306,349
	Contingent Subtotal					\$1,327,511
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$66,376
	Construction Cost Subtotal					\$1,393,887
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$334,533
	Project Delivery Cost Subtotal					\$1,728,420
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$241,979
CAPITAL COST						\$1,970,399

Gas Conditioning - New and Rehab Existing

Demolition						
	Demolition Excluded					
New Equipment Cost						
	H2S Reduction	\$/each	\$275,000	1	1.6	\$429,000
	Moisture Reduction/Compression	\$/each	\$710,000	1	1.6	\$1,107,600
	Siloxane Reduction	\$/each	\$300,000	1	1.6	\$468,000
	Equipment Subtotal					\$2,004,600
Rehab Existing	Allowance	%	0.0%	1	1.0	\$0
RNG Upgrading system		\$/each	\$2,400,000	0	1.6	\$0
Slab						
	Slab	\$/sf	\$63	400	1.0	\$25,084
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$25,084
	System Subtotal					\$2,029,684
Sitework	Sitework	%	5.0%			\$101,484
	Direct Cost Subtotal					\$2,131,169
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$2,131,169
Contractor Markup	Contractor Markup	%	37.4%			\$796,703
	Marked Up Subtotal					\$2,927,871
	Contingency	%	30.0%			\$878,361
	Contingent Subtotal					\$3,806,233
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$190,312
	Construction Cost Subtotal					\$3,996,545
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$959,171
	Project Delivery Cost Subtotal					\$4,955,715
Gresham Admin Fee						

	Options 1A/1B/1C: Renewable Electricity					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Gresham Administration Charge	%	14.0%			\$693,800
CAPITAL COST						\$5,649,515

CHP

Demolition						
	Demolition Excluded					
Equipment Cost						
	2x 800 kW Caterpillar w/ Enclosure	\$/each	\$1,300,000	2	1.6	\$4,056,000
	LCFS Compliance Costs	\$/each	\$45,000	1	1.6	\$70,200
	Biogas Storage Vessel	\$/each	\$405,000	1	1.6	\$648,000
	Equipment Subtotal					\$4,774,200
Slab						
	Slab	\$/sf	\$63	832	1.0	\$52,176
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$52,176
	System Subtotal					\$4,826,376
Sitework	Sitework	%	5.0%			\$241,319
	Direct Cost Subtotal					\$5,067,694
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$5,067,694
Contractor Markup	Contractor Markup	%	37.4%			\$1,894,475
	Marked Up Subtotal					\$6,962,170
	Contingency	%	30.0%			\$2,088,651
	Contingent Subtotal					\$9,050,821
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$452,541
	Construction Cost Subtotal					\$9,503,362
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,280,807
	Project Delivery Cost Subtotal					\$11,784,169
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,649,784
CAPITAL COST						\$13,433,952

Boiler

Demolition						
	Demolition Excluded					
Equipment Cost						
	Hot Water Boiler	\$/each	\$119,000	3	1.6	\$556,920
	Equipment Subtotal					\$556,920
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$556,920
Sitework	Sitework	%	43.0%			\$239,476
	Direct Cost Subtotal					\$796,396
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$796,396
Contractor Markup	Contractor Markup	%	37.4%			\$297,720
	Marked Up Subtotal					\$1,094,115
	Contingency	%	30.0%			\$328,235
	Contingent Subtotal					\$1,422,350
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$71,117
	Construction Cost Subtotal					\$1,493,467
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$358,432
	Project Delivery Cost Subtotal					\$1,851,899
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$259,266
CAPITAL COST						\$2,111,165

CAPITAL COST SUMMARY

FOG and Food Waste Receiving Facility - New and Rehab Existing	\$2,856,282
Anaerobic Digester System - Convert Existing Tanks	\$11,871,282
Anaerobic Digester System - New Tank	\$17,257,464
Dewatering, Cake Conveyance, and Cake Storage	\$1,970,399
Gas Conditioning - New and Rehab Existing	\$5,649,515
CHP	\$13,433,952
Boiler	\$2,111,165
Grant Funding	\$0
Total Direct Cost	\$20,804,276
Total Project Cost	\$55,150,061

Option 1a-ii w/MHP+TAD: Renewable Electricity						
Item		Unit	Unit Cost	Qty	Installation Factor	Cost
FOG and Food Waste Receiving Facility - New and Rehab Existing						
Demolition						
	Demolition Excluded					
Equipment Cost						
	Receiving Station Rock Trap	\$/each	\$10,000	0	1.6	\$0
	Receiving Station Grinder	\$/each	\$80,000	0	1.6	\$0
	Receiving Station Storage Tank	\$/each	\$39,000	3	1.6	\$182,520
	Receiving Station Unloading Pump	\$/each	\$70,000	2	1.6	\$218,400
	Receiving Station FOG Recirculation Pump	\$/each	\$20,000	2	1.6	\$62,400
	Receiving Station Mixer	\$/each	\$116,000	0	1.6	\$0
	Receiving Station Heat Exchanger	\$/each	\$100,000	0	1.6	\$0
	Receiving Station FOG Feed Pump	\$/each	\$30,000	2	1.6	\$93,600
	Receiving Station Hot Water Pressure Washer	\$/each	\$16,000	1	1.6	\$24,960
	Receiving Station Odor Control System	\$/each	\$225,000	1	1.6	\$351,000
	Equipment Subtotal					\$932,880
Existing FOG System Rehab (Allowance)		%	10.0%	1	1	\$93,288
Equipment Subtotal						\$1,026,168
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$1,026,168
Sitework	Sitework	%	5.0%			\$51,308
	Direct Cost Subtotal					\$1,077,476
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,077,476
Contractor Markup	Contractor Markup	%	37.4%			\$402,797
	Marked Up Subtotal					\$1,480,273
	Contingency	%	30.0%			\$444,082
	Contingent Subtotal					\$1,924,356
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$96,218
	Construction Cost Subtotal					\$2,020,573
Project Delivery						
	Engineering/Administration/Legal	%	24.0%			\$484,938
	Project Delivery Cost Subtotal					\$2,505,511
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$350,772
CAPITAL COST						\$2,856,282

Anaerobic Digester System - Convert Existing Tanks

Demolition						
	Demolition Included Below					
Equipment Cost						
	Convert Existing Tanks to Thermophilic					
	Digester Tank	\$/gal	\$2.22	0	1.6	\$0
	Mixing System	\$/each	\$100,000	0	1.6	\$0
	Mixing System -LMM Rehab	\$/each	\$292,000	1	1.6	\$467,200
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	0	1.6	\$0
	Solids Recirculation Pumps	\$/each	\$25,000	0	1.6	\$0
	Hot Water Recirculation Pumps	\$/each	\$10,000	0	1.6	\$0
	Digester Fixed Cover Replacement	\$/each	\$1,226,000	2	1.6	\$3,923,200
	Digested Solids Transfer Pumps	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$4,390,400
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$4,390,400
Sitework	Sitework	%	0%			\$0
	Demolition	%	2.0%			\$87,808
	Direct Cost Subtotal					\$4,478,208
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$4,478,208
Contractor Markup	Contractor Markup	%	37.4%			\$1,674,105
	Marked Up Subtotal					\$6,152,313
	Contingency	%	30.0%			\$1,845,694
	Contingent Subtotal					\$7,998,007
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$399,900
	Construction Cost Subtotal					\$8,397,908
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,015,498
	Project Delivery Cost Subtotal					\$10,413,406
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,457,877
CAPITAL COST						\$11,871,282

Anaerobic Digester System - New Tank

Demolition						
	Demolition Excluded					
Equipment Cost	Build New Thermophilic Tank					
	MHP Tank	\$/each	\$297,000.00	4	1.6	\$1,900,800
	Digester Tank	\$/gal	\$2.44	1000000	1.0	\$2,440,000
	MHP Mixing System	\$/each	\$100,000	4	1.6	\$624,000
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	2	1.6	\$218,400
	Solids Recirculation Pumps	\$/each	\$25,000	6	1.6	\$234,000
	Hot Water Recirculation Pumps	\$/each	\$10,000	6	1.6	\$93,600

	Option 1a-ii w/MHP+TAD: Renewable Electricity					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Digested Solids Transfer Pumps	\$/each	\$45,000	4	1.6	\$280,800
	LMM Mixing System for TAD	\$/each	\$405,000	1	1.6	\$631,800
	Equipment Subtotal					\$6,423,400
Building						
	Building	\$/sf	\$400	2,500	1.0	\$1,000,000
	Odor Control	\$/scfm	\$65	1,875	1.0	\$121,875
	Buildings Subtotal					\$1,121,875
	System Subtotal					\$7,545,275
Sitework	Sitework	%	43.0%			\$3,244,468
	Direct Cost Subtotal					\$10,789,743
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$10,789,743
Contractor Markup	Contractor Markup	%	37.4%			\$4,033,570
	Marked Up Subtotal					\$14,823,314
	Contingency	%	30.0%			\$4,446,994
	Contingent Subtotal					\$19,270,308
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$963,515
	Construction Cost Subtotal					\$20,233,823
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$4,856,118
	Project Delivery Cost Subtotal					\$25,089,941
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$3,512,592
CAPITAL COST						\$28,602,532

Dewatering, Cake Conveyance, and Cake Storage

Demolition						
	Demolition Excluded					
Equipment Cost						
	Cake Storage	\$/cf	3.34	118,800	1.6	\$619,412
	Equipment Subtotal					\$619,412
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$619,412
Sitework	Sitework	%	20.0%			\$123,882
	Direct Cost Subtotal					\$743,294
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$743,294
Contractor Markup	Contractor Markup	%	37.4%			\$277,868
	Marked Up Subtotal					\$1,021,163
	Contingency	%	30.0%			\$306,349
	Contingent Subtotal					\$1,327,511
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$66,376
	Construction Cost Subtotal					\$1,393,887
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$334,533
	Project Delivery Cost Subtotal					\$1,728,420
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$241,979
CAPITAL COST						\$1,970,399

Gas Conditioning - New and Rehab Existing

Demolition						
	Demolition Excluded					
New Equipment Cost						
	H2S Reduction	\$/each	\$275,000	1	1.6	\$429,000
	Moisture Reduction/Compression	\$/each	\$710,000	1	1.6	\$1,107,600
	Siloxane Reduction	\$/each	\$300,000	1	1.6	\$468,000
	Equipment Subtotal					\$2,004,600
Rehab Existing	Allowance	%	0.0%	1	1.0	\$0
RNG Upgrading system		\$/each	\$2,400,000	0	1.6	\$0
Slab						
	Slab	\$/sf	\$63	400	1.0	\$25,084
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$25,084
	System Subtotal					\$2,029,684
Sitework	Sitework	%	5.0%			\$101,484
	Direct Cost Subtotal					\$2,131,169
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$2,131,169
Contractor Markup	Contractor Markup	%	37.4%			\$796,703
	Marked Up Subtotal					\$2,927,871
	Contingency	%	30.0%			\$878,361
	Contingent Subtotal					\$3,806,233
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$190,312
	Construction Cost Subtotal					\$3,996,545
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$959,171
	Project Delivery Cost Subtotal					\$4,955,715
Gresham Admin Fee						

	Option 1a-ii w/MHP+TAD: Renewable Electricity					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Gresham Administration Charge	%	14.0%			\$693,800
CAPITAL COST						\$5,649,515

CHP

Demolition						
	Demolition Excluded					
Equipment Cost						
	2x 800 kW Caterpillar w/ Enclosure	\$/each	\$1,300,000	2	1.6	\$4,056,000
	LCFS Compliance Costs	\$/each	\$45,000	1	1.6	\$70,200
	Biogas Storage Vessel	\$/each	\$405,000	1	1.6	\$648,000
	Equipment Subtotal					\$4,774,200
Slab						
	Slab	\$/sf	\$63	832	1.0	\$52,176
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$52,176
	System Subtotal					\$4,826,376
Sitework	Sitework	%	5.0%			\$241,319
	Direct Cost Subtotal					\$5,067,694
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$5,067,694
Contractor Markup	Contractor Markup	%	37.4%			\$1,894,475
	Marked Up Subtotal					\$6,962,170
	Contingency	%	30.0%			\$2,088,651
	Contingent Subtotal					\$9,050,821
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$452,541
	Construction Cost Subtotal					\$9,503,362
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,280,807
	Project Delivery Cost Subtotal					\$11,784,169
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,649,784
CAPITAL COST						\$13,433,952

Boiler

Demolition						
	Demolition Excluded					
Equipment Cost						
	Hot Water Boiler	\$/each	\$119,000	3	1.6	\$556,920
	Equipment Subtotal					\$556,920
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$556,920
Sitework	Sitework	%	43.0%			\$239,476
	Direct Cost Subtotal					\$796,396
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$796,396
Contractor Markup	Contractor Markup	%	37.4%			\$297,720
	Marked Up Subtotal					\$1,094,115
	Contingency	%	30.0%			\$328,235
	Contingent Subtotal					\$1,422,350
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$71,117
	Construction Cost Subtotal					\$1,493,467
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$358,432
	Project Delivery Cost Subtotal					\$1,851,899
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$259,266
CAPITAL COST						\$2,111,165

CAPITAL COST SUMMARY		
FOG and Food Waste Receiving Facility - New and Rehab Existing		\$2,856,282
Anaerobic Digester System - Convert Existing Tanks		\$11,871,282
Anaerobic Digester System - New Tank		\$28,602,532
Dewatering, Cake Conveyance, and Cake Storage		\$1,970,399
Gas Conditioning - New and Rehab Existing		\$5,649,515
CHP		\$13,433,952
Boiler		\$2,111,165
Grant Funding		\$0
Total Direct Cost		\$25,083,980
Total Project Cost		\$66,495,129

Option 1a-iii w/MHP+MAD: Rewenable Electricity						
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
FOG and Food Waste Receiving Facility - New and Rehab Existing						
Demolition						
	Demolition Excluded					
Equipment Cost						
	Receiving Station Rock Trap	\$/each	\$10,000	0	1.6	\$0
	Receiving Station Grinder	\$/each	\$80,000	0	1.6	\$0
	Receiving Station Storage Tank	\$/each	\$39,000	3	1.6	\$182,520
	Receiving Station Unloading Pump	\$/each	\$70,000	2	1.6	\$218,400
	Receiving Station FOG Recirculation Pump	\$/each	\$20,000	2	1.6	\$62,400
	Receiving Station Mixer	\$/each	\$116,000	0	1.6	\$0
	Receiving Station Heat Exchanger	\$/each	\$100,000	0	1.6	\$0
	Receiving Station FOG Feed Pump	\$/each	\$30,000	2	1.6	\$93,600
	Receiving Station Hot Water Pressure Washer	\$/each	\$16,000	1	1.6	\$24,960
	Receiving Station Odor Control System	\$/each	\$225,000	1	1.6	\$351,000
	Equipment Subtotal					\$932,880
Existing FOG System Rehab (Allowance)		%	10.0%	1	1	\$93,288
Equipment Subtotal						\$1,026,168
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$1,026,168
Sitework	Sitework	%	5.0%			\$51,308
	Direct Cost Subtotal					\$1,077,476
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,077,476
Contractor Markup	Contractor Markup	%	37.4%			\$402,797
	Marked Up Subtotal					\$1,480,273
	Contingency	%	30.0%			\$444,082
	Contingent Subtotal					\$1,924,356
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$96,218
	Construction Cost Subtotal					\$2,020,573
Project Delivery						
	Engineering/Administration/Legal	%	24.0%			\$484,938
	Project Delivery Cost Subtotal					\$2,505,511
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$350,772
CAPITAL COST						\$2,856,282

Anaerobic Digester System - Convert Existing Tanks

Demolition						
	Demolition Included Below					
Equipment Cost						
	Convert Existing Tanks to Thermophilic					
	Digester Tank	\$/gal	\$2.22	0	1.6	\$0
	Mixing System	\$/each	\$100,000	0	1.6	\$0
	Mixing System -LMM Rehab	\$/each	\$292,000	1	1.6	\$467,200
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	0	1.6	\$0
	Solids Recirculation Pumps	\$/each	\$25,000	0	1.6	\$0
	Hot Water Recirculation Pumps	\$/each	\$10,000	0	1.6	\$0
	Digester Fixed Cover Replacement	\$/each	\$1,226,000	2	1.6	\$3,923,200
	Digested Solids Transfer Pumps	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$4,390,400
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$4,390,400
Sitework	Sitework	%	0%			\$0
	Demolition	%	2.0%			\$87,808
	Direct Cost Subtotal					\$4,478,208
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$4,478,208
Contractor Markup	Contractor Markup	%	37.4%			\$1,674,105
	Marked Up Subtotal					\$6,152,313
	Contingency	%	30.0%			\$1,845,694
	Contingent Subtotal					\$7,998,007
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$399,900
	Construction Cost Subtotal					\$8,397,908
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,015,498
	Project Delivery Cost Subtotal					\$10,413,406
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,457,877
CAPITAL COST						\$11,871,282

Anaerobic Digester System - New Tank

Demolition						
	Demolition Excluded					
Equipment Cost	Build New Thermophilic Tank					
	Recuperative RDT	\$/each	\$200,000	1	1.6	\$320,000
	MHP Tank	\$/each	\$297,000.00	4	1.6	\$1,900,800
	Digester Tank	\$/gal	\$2.44	0	1.0	\$0
	MHP Mixing System	\$/each	\$100,000	4	1.6	\$624,000
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	2	1.6	\$218,400
	Solids Recirculation Pumps	\$/each	\$25,000	4	1.6	\$156,000
	Hot Water Recirculation Pumps	\$/each	\$10,000	4	1.6	\$62,400

	Option 1a-iii w/MHP+MAD: Rewenable Electricity					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Digested Solids Transfer Pumps	\$/each	\$45,000	4	1.6	\$280,800
	LMM Mixing System for TAD	\$/each	\$405,000	0	1.6	\$0
	Equipment Subtotal					\$3,562,400
Building						
	Building	\$/sf	\$400	1,000	1.0	\$400,000
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$400,000
	System Subtotal					\$3,962,400
Sitework	Sitework	%	43.0%			\$1,703,832
	Direct Cost Subtotal					\$5,666,232
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$5,666,232
Contractor Markup	Contractor Markup	%	37.4%			\$2,118,229
	Marked Up Subtotal					\$7,784,461
	Contingency	%	30.0%			\$2,335,338
	Contingent Subtotal					\$10,119,799
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$505,990
	Construction Cost Subtotal					\$10,625,789
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,550,189
	Project Delivery Cost Subtotal					\$13,175,979
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,844,637
CAPITAL COST						\$15,020,616

Dewatering, Cake Conveyance, and Cake Storage

Demolition						
	Demolition Excluded					
Equipment Cost						
	Cake Storage	\$/cf	3.34	89,100	1.6	\$464,559
	Equipment Subtotal					\$464,559
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$464,559
Sitework	Sitework	%	20.0%			\$92,912
	Direct Cost Subtotal					\$557,471
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$557,471
Contractor Markup	Contractor Markup	%	37.4%			\$208,401
	Marked Up Subtotal					\$765,872
	Contingency	%	30.0%			\$229,762
	Contingent Subtotal					\$995,634
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$49,782
	Construction Cost Subtotal					\$1,045,415
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$250,900
	Project Delivery Cost Subtotal					\$1,296,315
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$181,484
CAPITAL COST						\$1,477,799

Gas Conditioning - New and Rehab Existing

Demolition						
	Demolition Excluded					
New Equipment Cost						
	H2S Reduction	\$/each	\$275,000	1	1.6	\$429,000
	Moisture Reduction/Compression	\$/each	\$710,000	1	1.6	\$1,107,600
	Siloxane Reduction	\$/each	\$300,000	1	1.6	\$468,000
	Equipment Subtotal					\$2,004,600
Rehab Existing	Allowance	%	0.0%	1	1.0	\$0
RNG Upgrading system		\$/each	\$2,400,000	0	1.6	\$0
Slab						
	Slab	\$/sf	\$63	400	1.0	\$25,084
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$25,084
	System Subtotal					\$2,029,684
Sitework	Sitework	%	5.0%			\$101,484
	Direct Cost Subtotal					\$2,131,169
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$2,131,169
Contractor Markup	Contractor Markup	%	37.4%			\$796,703
	Marked Up Subtotal					\$2,927,871
	Contingency	%	30.0%			\$878,361
	Contingent Subtotal					\$3,806,233
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$190,312
	Construction Cost Subtotal					\$3,996,545
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$959,171
	Project Delivery Cost Subtotal					\$4,955,715
Gresham Admin Fee						

	Option 1a-iii w/MHP+MAD: Renewable Electricity					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Gresham Administration Charge	%	14.0%			\$693,800
CAPITAL COST						\$5,649,515

CHP						
Demolition						
	Demolition Excluded					
Equipment Cost						
	2x 800 kW Caterpillar w/ Enclosure	\$/each	\$1,300,000	2	1.6	\$4,056,000
	LCFS Compliance Costs	\$/each	\$45,000	1	1.6	\$70,200
	Biogas Storage Vessel	\$/each	\$405,000	1	1.6	\$648,000
	Equipment Subtotal					\$4,774,200
Slab						
	Slab	\$/sf	\$63	832	1.0	\$52,176
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$52,176
	System Subtotal					\$4,826,376
Sitework	Sitework	%	5.0%			\$241,319
	Direct Cost Subtotal					\$5,067,694
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$5,067,694
Contractor Markup	Contractor Markup	%	37.4%			\$1,894,475
	Marked Up Subtotal					\$6,962,170
	Contingency	%	30.0%			\$2,088,651
	Contingent Subtotal					\$9,050,821
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$452,541
	Construction Cost Subtotal					\$9,503,362
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,280,807
	Project Delivery Cost Subtotal					\$11,784,169
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,649,784
CAPITAL COST						\$13,433,952

Boiler						
Demolition						
	Demolition Excluded					
Equipment Cost						
	Hot Water Boiler	\$/each	\$119,000	3	1.6	\$556,920
	Equipment Subtotal					\$556,920
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$556,920
Sitework	Sitework	%	43.0%			\$239,476
	Direct Cost Subtotal					\$796,396
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$796,396
Contractor Markup	Contractor Markup	%	37.4%			\$297,720
	Marked Up Subtotal					\$1,094,115
	Contingency	%	30.0%			\$328,235
	Contingent Subtotal					\$1,422,350
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$71,117
	Construction Cost Subtotal					\$1,493,467
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$358,432
	Project Delivery Cost Subtotal					\$1,851,899
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$259,266
CAPITAL COST						\$2,111,165

CAPITAL COST SUMMARY		
FOG and Food Waste Receiving Facility - New and Rehab Existing		\$2,856,282
Anaerobic Digester System - Convert Existing Tanks		\$11,871,282
Anaerobic Digester System - New Tank		\$15,020,616
Dewatering, Cake Conveyance, and Cake Storage		\$1,477,799
Gas Conditioning - New and Rehab Existing		\$5,649,515
CHP		\$13,433,952
Boiler		\$2,111,165
Grant Funding		\$0
Total Direct Cost		\$19,774,646
Total Project Cost		\$52,420,612

Option 2A: Renewable Natural Gas (Tap incentive/credit markets)						
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
FOG and Food Waste Receiving Facility - New and Rehab Existing						
Demolition						
	Demolition Excluded					
Equipment Cost						
	Receiving Station Rock Trap	\$/each	\$10,000	0	1.6	\$0
	Receiving Station Grinder	\$/each	\$80,000	0	1.6	\$0
	Receiving Station Storage Tank	\$/each	\$39,000	3	1.6	\$182,520
	Receiving Station Unloading Pump	\$/each	\$70,000	2	1.6	\$218,400
	Receiving Station FOG Recirculation Pump	\$/each	\$20,000	2	1.6	\$62,400
	Receiving Station Mixer	\$/each	\$116,000	0	1.6	\$0
	Receiving Station Heat Exchanger	\$/each	\$100,000	0	1.6	\$0
	Receiving Station FOG Feed Pump	\$/each	\$30,000	2	1.6	\$93,600
	Receiving Station Hot Water Pressure Washer	\$/each	\$16,000	1	1.6	\$24,960
	Receiving Station Odor Control System	\$/each	\$225,000	1	1.6	\$351,000
	Equipment Subtotal					\$932,880
Existing FOG System Rehab (Allowance)		%	10.0%	1	1	\$93,288
Equipment Subtotal	Equipment Subtotal					
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$1,026,168
Sitework	Sitework	%	5.0%			\$51,308
	Direct Cost Subtotal					\$1,077,476
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,077,476
Contractor Markup	Contractor Markup	%	37.4%			\$402,797
	Marked Up Subtotal					\$1,480,273
	Contingency	%	30.0%			\$444,082
	Contingent Subtotal					\$1,924,356
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$96,218
	Construction Cost Subtotal					\$2,020,573
Project Delivery						
	Engineering/Administration/Legal	%	24.0%			\$484,938
	Project Delivery Cost Subtotal					\$2,505,511
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$350,772
CAPITAL COST						\$2,856,282

Anaerobic Digester System - Convert Existing Tanks

Demolition						
	Demolition Included Below					
Equipment Cost						
	Convert Existing Tanks to Thermophilic					
	Digester Tank	\$/gal	\$2.22	0	1.6	\$0
	Mixing System	\$/each	\$100,000	0	1.6	\$0
	Mixing System -LMM Rehab	\$/each	\$292,000	1	1.6	\$467,200
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	0	1.6	\$0
	Solids Recirculation Pumps	\$/each	\$25,000	0	1.6	\$0
	Hot Water Recirculation Pumps	\$/each	\$10,000	0	1.6	\$0
	Digester Fixed Cover Replacement	\$/each	\$1,226,000	2	1.6	\$3,923,200
	Digested Solids Transfer Pumps	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$4,390,400
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$4,390,400
Sitework	Sitework	%	0%			\$0
	Demolition	%	2.0%			\$87,808
	Direct Cost Subtotal					\$4,478,208
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$4,478,208
Contractor Markup	Contractor Markup	%	37.4%			\$1,674,105
	Marked Up Subtotal					\$6,152,313
	Contingency	%	30.0%			\$1,845,694
	Contingent Subtotal					\$7,998,007
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$399,900
	Construction Cost Subtotal					\$8,397,908
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,015,498
	Project Delivery Cost Subtotal					\$10,413,406
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,457,877
CAPITAL COST						\$11,871,282

Anaerobic Digester System - New Tank

Demolition						
	Demolition Excluded					
Equipment Cost						
	Build New Thermophilic Tank					
	Digester Tank	\$/gal	\$2.44	1000000	1.0	\$2,440,000
	Mixing System	\$/each	\$405,000	1	1.6	\$631,800
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	1	1.6	\$109,200
	Solids Recirculation Pumps	\$/each	\$25,000	2	1.6	\$78,000
	Hot Water Recirculation Pumps	\$/each	\$10,000	2	1.6	\$31,200

	Option 2A: Renewable Natural Gas (Tap incentive/credit markets)					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Digested Solids Transfer Pumps	\$/each	\$45,000	2	1.6	\$140,400
	Equipment Subtotal					\$3,430,600
Building						
	Building	\$/sf	\$400	2,500	1.0	\$1,000,000
	Odor Control	\$/scfm	\$65	1,875	1.0	\$121,875
	Buildings Subtotal					\$1,121,875
	System Subtotal					\$4,552,475
Sitework	Sitework	%	43.0%			\$1,957,564
	Direct Cost Subtotal					\$6,510,039
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$6,510,039
Contractor Markup	Contractor Markup	%	37.4%			\$2,433,673
	Marked Up Subtotal					\$8,943,712
	Contingency	%	30.0%			\$2,683,114
	Contingent Subtotal					\$11,626,825
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$581,341
	Construction Cost Subtotal					\$12,208,167
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,929,960
	Project Delivery Cost Subtotal					\$15,138,127
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$2,119,338
CAPITAL COST						\$17,257,464

Dewatering, Cake Conveyance, and Cake Storage

Demolition						
	Demolition Excluded					
Equipment Cost						
	Cake Storage	\$/cf	3.34	118,800	1.6	\$619,412
	Equipment Subtotal					\$619,412
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$619,412
Sitework	Sitework	%	20.0%			\$123,882
	Direct Cost Subtotal					\$743,294
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$743,294
Contractor Markup	Contractor Markup	%	37.4%			\$277,868
	Marked Up Subtotal					\$1,021,163
	Contingency	%	30.0%			\$306,349
	Contingent Subtotal					\$1,327,511
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$66,376
	Construction Cost Subtotal					\$1,393,887
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$334,533
	Project Delivery Cost Subtotal					\$1,728,420
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$241,979
CAPITAL COST						\$1,970,399

Gas Conditioning - New and Rehab Existing

Demolition						
	Demolition Excluded					
New Equipment Cost						
	H2S Reduction	\$/each	\$275,000	1	1.6	\$429,000
	Moisture Reduction/Compression	\$/each	\$710,000	1	1.6	\$1,107,600
	Siloxane Reduction	\$/each	\$300,000	1	1.6	\$468,000
	Equipment Subtotal					\$2,004,600
Rehab Existing	Allowance	%	0.0%	1	1.0	\$0
RNG Upgrading system		\$/each	\$2,400,000	2	1.2	\$5,760,000
Slab						
	Slab	\$/sf	\$63	400	1.0	\$25,084
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$25,084
	System Subtotal					\$7,789,684
Sitework	Sitework	%	5.0%			\$389,484
	Direct Cost Subtotal					\$8,179,169
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$8,179,169
Contractor Markup	Contractor Markup	%	37.4%			\$3,057,650
	Marked Up Subtotal					\$11,236,818
	Contingency	%	30.0%			\$3,371,045
	Contingent Subtotal					\$14,607,864
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$730,393
	Construction Cost Subtotal					\$15,338,257
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$3,681,182
	Project Delivery Cost Subtotal					\$19,019,438
Gresham Admin Fee						

	Option 2A: Renewable Natural Gas (Tap incentive/credit markets)					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Gresham Administration Charge	%	14.0%			\$2,662,721
	NWN Interconnection Charge	\$/each	\$2,500,000			\$2,500,000
CAPITAL COST						\$24,182,160

CHP

Demolition						
	Demolition Excluded					
Equipment Cost						
	400 kW Caterpillar w/ Enclosure	\$/each	\$1,175,000	0	1.6	\$0
	LCFS Compliance Costs	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$0
Slab						
	Slab	\$/sf	\$63	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$0
Sitework	Sitework	%	5.0%			\$0
	Direct Cost Subtotal					\$0
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$0
Contractor Markup	Contractor Markup	%	37.4%			\$0
	Marked Up Subtotal					\$0
	Contingency	%	30.0%			\$0
	Contingent Subtotal					\$0
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$0
	Construction Cost Subtotal					\$0
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$0
	Project Delivery Cost Subtotal					\$0
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$0
CAPITAL COST						\$0

Boiler

Demolition						
	Demolition Excluded					
Equipment Cost						
	Hot Water Boiler	\$/each	\$119,000	5	1.6	\$928,200
	Equipment Subtotal					\$928,200
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$928,200
Sitework	Sitework	%	43.0%			\$399,126
	Direct Cost Subtotal					\$1,327,326
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,327,326
Contractor Markup	Contractor Markup	%	37.4%			\$496,199
	Marked Up Subtotal					\$1,823,525
	Contingency	%	30.0%			\$547,058
	Contingent Subtotal					\$2,370,583
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$118,529
	Construction Cost Subtotal					\$2,489,112
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$597,387
	Project Delivery Cost Subtotal					\$3,086,499
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$432,110
CAPITAL COST						\$3,518,609

CAPITAL COST SUMMARY		
FOG and Food Waste Receiving Facility - New and Rehab Existing		\$2,856,282
Anaerobic Digester System - Convert Existing Tanks		\$11,871,282
Anaerobic Digester System - New Tank		\$17,257,464
Dewatering, Cake Conveyance, and Cake Storage		\$1,970,399
Gas Conditioning - New and Rehab Existing		\$24,182,160
CHP		\$0
Boiler		\$3,518,609
Grant Funding		\$0
Total Direct Cost		\$22,315,512
Total Project Cost		

Option 2B: Renewable Natural Gas (Long Term Agreement with NorthWest Natural)						
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
FOG and Food Waste Receiving Facility - New and Rehab Existing						
Demolition						
	Demolition Excluded					
Equipment Cost						
	Receiving Station Rock Trap	\$/each	\$10,000	0	1.6	\$0
	Receiving Station Grinder	\$/each	\$80,000	0	1.6	\$0
	Receiving Station Storage Tank	\$/each	\$39,000	3	1.6	\$182,520
	Receiving Station Unloading Pump	\$/each	\$70,000	2	1.6	\$218,400
	Receiving Station FOG Recirculation Pump	\$/each	\$20,000	2	1.6	\$62,400
	Receiving Station Mixer	\$/each	\$116,000	0	1.6	\$0
	Receiving Station Heat Exchanger	\$/each	\$100,000	0	1.6	\$0
	Receiving Station FOG Feed Pump	\$/each	\$30,000	2	1.6	\$93,600
	Receiving Station Hot Water Pressure Washer	\$/each	\$16,000	1	1.6	\$24,960
	Receiving Station Odor Control System	\$/each	\$225,000	1	1.6	\$351,000
	Equipment Subtotal					\$932,880
Existing FOG System Rehab (Allowance)		%	10.0%	1	1	\$93,288
Equipment Subtotal	Equipment Subtotal					
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$1,026,168
Sitework	Sitework	%	5.0%			\$51,308
	Direct Cost Subtotal					\$1,077,476
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,077,476
Contractor Markup	Contractor Markup	%	37.4%			\$402,797
	Marked Up Subtotal					\$1,480,273
	Contingency	%	30.0%			\$444,082
	Contingent Subtotal					\$1,924,356
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$96,218
	Construction Cost Subtotal					\$2,020,573
Project Delivery						
	Engineering/Administration/Legal	%	24.0%			\$484,938
	Project Delivery Cost Subtotal					\$2,505,511
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$350,772
CAPITAL COST						\$2,856,282

Anaerobic Digester System - Convert Existing Tanks

Demolition						
	Demolition Included Below					
Equipment Cost						
	Convert Existing Tanks to Thermophilic					
	Digester Tank	\$/gal	\$2.22	0	1.6	\$0
	Mixing System	\$/each	\$100,000	0	1.6	\$0
	Mixing System -LMM Rehab	\$/each	\$292,000	1	1.6	\$467,200
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	0	1.6	\$0
	Solids Recirculation Pumps	\$/each	\$25,000	0	1.6	\$0
	Hot Water Recirculation Pumps	\$/each	\$10,000	0	1.6	\$0
	Digester Fixed Cover Replacement	\$/each	\$1,226,000	2	1.6	\$3,923,200
	Digested Solids Transfer Pumps	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$4,390,400
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$4,390,400
Sitework	Sitework	%	0%			\$0
	Demolition	%	2.0%			\$87,808
	Direct Cost Subtotal					\$4,478,208
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$4,478,208
Contractor Markup	Contractor Markup	%	37.4%			\$1,674,105
	Marked Up Subtotal					\$6,152,313
	Contingency	%	30.0%			\$1,845,694
	Contingent Subtotal					\$7,998,007
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$399,900
	Construction Cost Subtotal					\$8,397,908
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,015,498
	Project Delivery Cost Subtotal					\$10,413,406
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,457,877
CAPITAL COST						\$11,871,282

Anaerobic Digester System - New Tank

Demolition						
	Demolition Excluded					
Equipment Cost						
	Build New Thermophilic Tank					
	Digester Tank	\$/gal	\$2.44	1000000	1.0	\$2,440,000
	Mixing System	\$/each	\$405,000	1	1.6	\$631,800
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	1	1.6	\$109,200
	Solids Recirculation Pumps	\$/each	\$25,000	2	1.6	\$78,000
	Hot Water Recirculation Pumps	\$/each	\$10,000	2	1.6	\$31,200

	Option 2B: Renewable Natural Gas (Long Term Agreement with NorthWest Natural)					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Digested Solids Transfer Pumps	\$/each	\$45,000	2	1.6	\$140,400
	Equipment Subtotal					\$3,430,600
Building						
	Building	\$/sf	\$400	2,500	1.0	\$1,000,000
	Odor Control	\$/scfm	\$65	1,875	1.0	\$121,875
	Buildings Subtotal					\$1,121,875
	System Subtotal					\$4,552,475
Sitework	Sitework	%	43.0%			\$1,957,564
	Direct Cost Subtotal					\$6,510,039
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$6,510,039
Contractor Markup	Contractor Markup	%	37.4%			\$2,433,673
	Marked Up Subtotal					\$8,943,712
	Contingency	%	30.0%			\$2,683,114
	Contingent Subtotal					\$11,626,825
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$581,341
	Construction Cost Subtotal					\$12,208,167
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,929,960
	Project Delivery Cost Subtotal					\$15,138,127
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$2,119,338
CAPITAL COST						\$17,257,464

Dewatering, Cake Conveyance, and Cake Storage

Demolition						
	Demolition Excluded					
Equipment Cost						
	Cake Storage	\$/cf	3.34	89,100	1.6	\$464,559
	Equipment Subtotal					\$464,559
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$464,559
Sitework	Sitework	%	20.0%			\$92,912
	Direct Cost Subtotal					\$557,471
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$557,471
Contractor Markup	Contractor Markup	%	37.4%			\$208,401
	Marked Up Subtotal					\$765,872
	Contingency	%	30.0%			\$229,762
	Contingent Subtotal					\$995,634
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$49,782
	Construction Cost Subtotal					\$1,045,415
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$250,900
	Project Delivery Cost Subtotal					\$1,296,315
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$181,484
CAPITAL COST						\$1,477,799

Gas Conditioning - New and Rehab Existing

Demolition						
	Demolition Excluded					
New Equipment Cost						
	H2S Reduction	\$/each	\$275,000	1	1.6	\$429,000
	Moisture Reduction/Compression	\$/each	\$710,000	1	1.6	\$1,107,600
	Siloxane Reduction	\$/each	\$300,000	1	1.6	\$468,000
	Equipment Subtotal					\$2,004,600
Rehab Existing	Allowance	%	0.0%	1	1.0	\$0
RNG Upgrading system		\$/each	\$2,400,000	2	1.2	\$5,760,000
Slab						
	Slab	\$/sf	\$63	400	1.0	\$25,084
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$25,084
	System Subtotal					\$7,789,684
Sitework	Sitework	%	5.0%			\$389,484
	Direct Cost Subtotal					\$8,179,169
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$8,179,169
Contractor Markup	Contractor Markup	%	37.4%			\$3,057,650
	Marked Up Subtotal					\$11,236,818
	Contingency	%	30.0%			\$3,371,045
	Contingent Subtotal					\$14,607,864
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$730,393
	Construction Cost Subtotal					\$15,338,257
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$3,681,182
	Project Delivery Cost Subtotal					\$19,019,438
Gresham Admin Fee						

	Option 2B: Renewable Natural Gas (Long Term Agreement with NorthWest Natural)					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Gresham Administration Charge	%	14.0%			\$2,662,721
	NWN Interconnection Charge	\$/each	\$2,500,000			\$2,500,000
CAPITAL COST						\$24,182,160

CHP

Demolition						
	Demolition Excluded					
Equipment Cost						
	400 kW Caterpillar w/ Enclosure	\$/each	\$1,175,000	0	1.6	\$0
	LCFS Compliance Costs	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$0
Slab						
	Slab	\$/sf	\$63	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$0
Sitework	Sitework	%	5.0%			\$0
	Direct Cost Subtotal					\$0
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$0
Contractor Markup	Contractor Markup	%	37.4%			\$0
	Marked Up Subtotal					\$0
	Contingency	%	30.0%			\$0
	Contingent Subtotal					\$0
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$0
	Construction Cost Subtotal					\$0
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$0
	Project Delivery Cost Subtotal					\$0
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$0
CAPITAL COST						\$0

Boiler

Demolition						
	Demolition Excluded					
Equipment Cost						
	Hot Water Boiler	\$/each	\$119,000	5	1.6	\$928,200
	Equipment Subtotal					\$928,200
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$928,200
Sitework	Sitework	%	43.0%			\$399,126
	Direct Cost Subtotal					\$1,327,326
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,327,326
Contractor Markup	Contractor Markup	%	37.4%			\$496,199
	Marked Up Subtotal					\$1,823,525
	Contingency	%	30.0%			\$547,058
	Contingent Subtotal					\$2,370,583
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$118,529
	Construction Cost Subtotal					\$2,489,112
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$597,387
	Project Delivery Cost Subtotal					\$3,086,499
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$432,110
CAPITAL COST						\$3,518,609

CAPITAL COST SUMMARY

FOG and Food Waste Receiving Facility - New and Rehab Existing	\$2,856,282
Anaerobic Digester System - Convert Existing Tanks	\$11,871,282
Anaerobic Digester System - New Tank	\$17,257,464
Dewatering, Cake Conveyance, and Cake Storage	\$1,477,799
Gas Conditioning - New and Rehab Existing	\$24,182,160
CHP	\$0
Boiler	\$3,518,609
Grant Funding	\$0
Total Direct Cost	\$22,129,689
Total Project Cost	\$61,163,597

	Option 3: Hybrid Approach					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
FOG and Food Waste Receiving Facility - New and Rehab Existing						
Demolition						
	Demolition Excluded					
Equipment Cost						
	Receiving Station Rock Trap	\$/each	\$10,000	0	1.6	\$0
	Receiving Station Grinder	\$/each	\$80,000	0	1.6	\$0
	Receiving Station Storage Tank	\$/each	\$39,000	3	1.6	\$182,520
	Receiving Station Unloading Pump	\$/each	\$70,000	2	1.6	\$218,400
	Receiving Station FOG Recirculation Pump	\$/each	\$20,000	2	1.6	\$62,400
	Receiving Station Mixer	\$/each	\$116,000	0	1.6	\$0
	Receiving Station Heat Exchanger	\$/each	\$100,000	0	1.6	\$0
	Receiving Station FOG Feed Pump	\$/each	\$30,000	2	1.6	\$93,600
	Receiving Station Hot Water Pressure Washer	\$/each	\$16,000	1	1.6	\$24,960
	Receiving Station Odor Control System	\$/each	\$225,000	1	1.6	\$351,000
	Equipment Subtotal					\$932,880
Existing FOG System Rehab (Allowance)		%	10.0%	1	1	\$93,288
Equipment Subtotal	Equipment Subtotal					
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$1,026,168
Sitework	Sitework	%	5.0%			\$51,308
	Direct Cost Subtotal					\$1,077,476
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,077,476
Contractor Markup	Contractor Markup	%	37.4%			\$402,797
	Marked Up Subtotal					\$1,480,273
	Contingency	%	30.0%			\$444,082
	Contingent Subtotal					\$1,924,356
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$96,218
	Construction Cost Subtotal					\$2,020,573
Project Delivery						
	Engineering/Administration/Legal	%	24.0%			\$484,938
	Project Delivery Cost Subtotal					\$2,505,511
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$350,772
CAPITAL COST						\$2,856,282

Anaerobic Digester System - Convert Existing Tanks

Demolition						
	Demolition Included Below					
Equipment Cost						
	Convert Existing Tanks to Thermophilic					
	Digester Tank	\$/gal	\$2.22	0	1.6	\$0
	Mixing System	\$/each	\$100,000	0	1.6	\$0
	Mixing System -LMM Rehab	\$/each	\$292,000	1	1.6	\$467,200
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	0	1.6	\$0
	Solids Recirculation Pumps	\$/each	\$25,000	0	1.6	\$0
	Hot Water Recirculation Pumps	\$/each	\$10,000	0	1.6	\$0
	Digester Fixed Cover Replacement	\$/each	\$1,226,000	2	1.6	\$3,923,200
	Digested Solids Transfer Pumps	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$4,390,400
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$4,390,400
Sitework	Sitework	%	0%			\$0
	Demolition	%	2.0%			\$87,808
	Direct Cost Subtotal					\$4,478,208
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$4,478,208
Contractor Markup	Contractor Markup	%	37.4%			\$1,674,105
	Marked Up Subtotal					\$6,152,313
	Contingency	%	30.0%			\$1,845,694
	Contingent Subtotal					\$7,998,007
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$399,900
	Construction Cost Subtotal					\$8,397,908
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,015,498
	Project Delivery Cost Subtotal					\$10,413,406
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,457,877
CAPITAL COST						\$11,871,282

Anaerobic Digester System - New Tank

Demolition						
	Demolition Excluded					
Equipment Cost						
	Build New Thermophilic Tank					
	Digester Tank	\$/gal	\$2.44	1000000	1.0	\$2,440,000
	Mixing System	\$/each	\$405,000	1	1.6	\$631,800
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	1	1.6	\$109,200
	Solids Recirculation Pumps	\$/each	\$25,000	2	1.6	\$78,000
	Hot Water Recirculation Pumps	\$/each	\$10,000	2	1.6	\$31,200

	Option 3: Hybrid Approach					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Digested Solids Transfer Pumps	\$/each	\$45,000	2	1.6	\$140,400
	Equipment Subtotal					\$3,430,600
Building						
	Building	\$/sf	\$400	2,500	1.0	\$1,000,000
	Odor Control	\$/scfm	\$65	1,875	1.0	\$121,875
	Buildings Subtotal					\$1,121,875
	System Subtotal					\$4,552,475
Sitework	Sitework	%	43.0%			\$1,957,564
	Direct Cost Subtotal					\$6,510,039
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$6,510,039
Contractor Markup	Contractor Markup	%	37.4%			\$2,433,673
	Marked Up Subtotal					\$8,943,712
	Contingency	%	30.0%			\$2,683,114
	Contingent Subtotal					\$11,626,825
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$581,341
	Construction Cost Subtotal					\$12,208,167
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,929,960
	Project Delivery Cost Subtotal					\$15,138,127
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$2,119,338
CAPITAL COST						\$17,257,464

Dewatering, Cake Conveyance, and Cake Storage

Demolition						
	Demolition Excluded					
Equipment Cost						
	Cake Storage	\$/cf	3.34	89,100	1.6	\$464,559
	Equipment Subtotal					\$464,559
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$464,559
Sitework	Sitework	%	20.0%			\$92,912
	Direct Cost Subtotal					\$557,471
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$557,471
Contractor Markup	Contractor Markup	%	37.4%			\$208,401
	Marked Up Subtotal					\$765,872
	Contingency	%	30.0%			\$229,762
	Contingent Subtotal					\$995,634
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$49,782
	Construction Cost Subtotal					\$1,045,415
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$250,900
	Project Delivery Cost Subtotal					\$1,296,315
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$181,484
CAPITAL COST						\$1,477,799

Gas Conditioning - New and Rehab Existing

Demolition						
	Demolition Excluded					
New Equipment Cost						
	H2S Reduction	\$/each	\$275,000	1	1.6	\$429,000
	Moisture Reduction/Compression	\$/each	\$710,000	1	1.6	\$1,107,600
	Siloxane Reduction	\$/each	\$300,000	1	1.6	\$468,000
	Equipment Subtotal					\$2,004,600
Rehab Existing	Allowance	%	0.0%	1	1.0	\$0
RNG Upgrading system		\$/each	\$2,400,000	2	1.2	\$5,760,000
Slab						
	Slab	\$/sf	\$63	400	1.0	\$25,084
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$25,084
	System Subtotal					\$7,789,684
Sitework	Sitework	%	5.0%			\$389,484
	Direct Cost Subtotal					\$8,179,169
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$8,179,169
Contractor Markup	Contractor Markup	%	37.4%			\$3,057,650
	Marked Up Subtotal					\$11,236,818
	Contingency	%	30.0%			\$3,371,045
	Contingent Subtotal					\$14,607,864
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$730,393
	Construction Cost Subtotal					\$15,338,257
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$3,681,182
	Project Delivery Cost Subtotal					\$19,019,438
Gresham Admin Fee						

	Option 3: Hybrid Approach					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Gresham Administration Charge	%	14.0%			\$2,662,721
	NWN Interconnection Charge	\$/each	\$2,500,000			\$2,500,000
CAPITAL COST						\$24,182,160

CHP

Demolition						
	Demolition Excluded					
Equipment Cost						
	600 kW Caterpillar w/o Enclosure	\$/each	\$1,075,000	1	1.6	\$1,677,000
	LCFS Compliance Costs	\$/each	\$45,000	0	1.6	\$0
	Biogas Storage Vessel	\$/each	\$405,000	1	1.6	\$648,000
	Equipment Subtotal					\$2,325,000
Slab						
	Slab	\$/sf	\$63	416	1.0	\$26,088
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$26,088
	System Subtotal					\$2,351,088
Sitework	Sitework	%	5.0%			\$117,554
	Direct Cost Subtotal					\$2,468,642
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$2,468,642
Contractor Markup	Contractor Markup	%	37.4%			\$922,862
	Marked Up Subtotal					\$3,391,504
	Contingency	%	30.0%			\$1,017,451
	Contingent Subtotal					\$4,408,955
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$220,448
	Construction Cost Subtotal					\$4,629,403
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$1,111,057
	Project Delivery Cost Subtotal					\$5,740,460
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$803,664
CAPITAL COST						\$6,544,124

Boiler

Demolition						
	Demolition Excluded					
Equipment Cost						
	Hot Water Boiler	\$/each	\$119,000	3	1.6	\$556,920
	Equipment Subtotal					\$556,920
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$556,920
Sitework	Sitework	%	43.0%			\$239,476
	Direct Cost Subtotal					\$796,396
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$796,396
Contractor Markup	Contractor Markup	%	37.4%			\$297,720
	Marked Up Subtotal					\$1,094,115
	Contingency	%	30.0%			\$328,235
	Contingent Subtotal					\$1,422,350
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$71,117
	Construction Cost Subtotal					\$1,493,467
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$358,432
	Project Delivery Cost Subtotal					\$1,851,899
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$259,266
CAPITAL COST						\$2,111,165

CAPITAL COST SUMMARY

FOG and Food Waste Receiving Facility - New and Rehab Existing	\$2,856,282
Anaerobic Digester System - Convert Existing Tanks	\$11,871,282
Anaerobic Digester System - New Tank	\$17,257,464
Dewatering, Cake Conveyance, and Cake Storage	\$1,477,799
Gas Conditioning - New and Rehab Existing	\$24,182,160
CHP	\$6,544,124
Boiler	\$2,111,165
Grant Funding	\$0
Total Direct Cost	\$24,067,401
Total Project Cost	\$66,300,277

Option 3: Hybrid Approach + MHP						
Item		Unit	Unit Cost	Qty	Installation Factor	Cost
FOG and Food Waste Receiving Facility - New and Rehab Existing						
Demolition						
	Demolition Excluded					
Equipment Cost						
	Receiving Station Rock Trap	\$/each	\$10,000	0	1.6	\$0
	Receiving Station Grinder	\$/each	\$80,000	0	1.6	\$0
	Receiving Station Storage Tank	\$/each	\$39,000	3	1.6	\$182,520
	Receiving Station Unloading Pump	\$/each	\$70,000	2	1.6	\$218,400
	Receiving Station FOG Recirculation Pump	\$/each	\$20,000	2	1.6	\$62,400
	Receiving Station Mixer	\$/each	\$116,000	0	1.6	\$0
	Receiving Station Heat Exchanger	\$/each	\$100,000	0	1.6	\$0
	Receiving Station FOG Feed Pump	\$/each	\$30,000	2	1.6	\$93,600
	Receiving Station Hot Water Pressure Washer	\$/each	\$16,000	1	1.6	\$24,960
	Receiving Station Odor Control System	\$/each	\$225,000	1	1.6	\$351,000
	Equipment Subtotal					\$932,880
Existing FOG System Rehab (Allowance)		%	10.0%	1	1	\$93,288
Equipment Subtotal	Equipment Subtotal					
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$1,026,168
Sitework	Sitework	%	5.0%			\$51,308
	Direct Cost Subtotal					\$1,077,476
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,077,476
Contractor Markup	Contractor Markup	%	37.4%			\$402,797
	Marked Up Subtotal					\$1,480,273
	Contingency	%	30.0%			\$444,082
	Contingent Subtotal					\$1,924,356
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$96,218
	Construction Cost Subtotal					\$2,020,573
Project Delivery						
	Engineering/Administration/Legal	%	24.0%			\$484,938
	Project Delivery Cost Subtotal					\$2,505,511
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$350,772
CAPITAL COST						\$2,856,282

Anaerobic Digester System - Convert Existing Tanks

Demolition						
	Demolition Included Below					
Equipment Cost						
	Convert Existing Tanks to Thermophilic					
	Digester Tank	\$/gal	\$2.22	0	1.6	\$0
	Mixing System	\$/each	\$100,000	0	1.6	\$0
	Mixing System -LMM Rehab	\$/each	\$292,000	1	1.6	\$467,200
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	0	1.6	\$0
	Solids Recirculation Pumps	\$/each	\$25,000	0	1.6	\$0
	Hot Water Recirculation Pumps	\$/each	\$10,000	0	1.6	\$0
	Digester Fixed Cover Replacement	\$/each	\$1,226,000	2	1.6	\$3,923,200
	Digested Solids Transfer Pumps	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$4,390,400
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$4,390,400
Sitework	Sitework	%	0%			\$0
	Demolition	%	2.0%			\$87,808
	Direct Cost Subtotal					\$4,478,208
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$4,478,208
Contractor Markup	Contractor Markup	%	37.4%			\$1,674,105
	Marked Up Subtotal					\$6,152,313
	Contingency	%	30.0%			\$1,845,694
	Contingent Subtotal					\$7,998,007
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$399,900
	Construction Cost Subtotal					\$8,397,908
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,015,498
	Project Delivery Cost Subtotal					\$10,413,406
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,457,877
CAPITAL COST						\$11,871,282

Anaerobic Digester System - New Tank

Demolition						
	Demolition Excluded					
Equipment Cost	Build New Thermophilic Tank					
	MHP Tank	\$/each	\$297,000.00	4	1.6	\$1,900,800
	Digester Tank	\$/gal	\$2.44	1000000	1.0	\$2,440,000
	MHP Mixing System	\$/each	\$100,000	4	1.6	\$624,000
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	4	1.6	\$436,800
	Solids Recirculation Pumps	\$/each	\$25,000	6	1.6	\$234,000
	Hot Water Recirculation Pumps	\$/each	\$10,000	6	1.6	\$93,600

	Option 3: Hybrid Approach + MHP					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Digested Solids Transfer Pumps	\$/each	\$45,000	4	1.6	\$280,800
	LMM Mixing System for TAD	\$/each	\$405,000	1	1.6	\$631,800
	Equipment Subtotal					\$6,641,800
Building						
	Building	\$/sf	\$400	2,500	1.0	\$1,000,000
	Odor Control	\$/scfm	\$65	1,875	1.0	\$121,875
	Buildings Subtotal					\$1,121,875
	System Subtotal					\$7,763,675
Sitework	Sitework	%	43.0%			\$3,338,380
	Direct Cost Subtotal					\$11,102,055
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$11,102,055
Contractor Markup	Contractor Markup	%	37.4%			\$4,150,323
	Marked Up Subtotal					\$15,252,378
	Contingency	%	30.0%			\$4,575,714
	Contingent Subtotal					\$19,828,092
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$991,405
	Construction Cost Subtotal					\$20,819,497
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$4,996,679
	Project Delivery Cost Subtotal					\$25,816,176
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$3,614,265
CAPITAL COST						\$29,430,440

Dewatering, Cake Conveyance, and Cake Storage

Demolition						
	Demolition Excluded					
Equipment Cost						
	Cake Storage	\$/cf	3.34	89,100	1.6	\$464,559
	Equipment Subtotal					\$464,559
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$464,559
Sitework	Sitework	%	20.0%			\$92,912
	Direct Cost Subtotal					\$557,471
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$557,471
Contractor Markup	Contractor Markup	%	37.4%			\$208,401
	Marked Up Subtotal					\$765,872
	Contingency	%	30.0%			\$229,762
	Contingent Subtotal					\$995,634
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$49,782
	Construction Cost Subtotal					\$1,045,415
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$250,900
	Project Delivery Cost Subtotal					\$1,296,315
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$181,484
CAPITAL COST						\$1,477,799

Gas Conditioning - New and Rehab Existing

Demolition						
	Demolition Excluded					
New Equipment Cost						
	H2S Reduction	\$/each	\$275,000	1	1.6	\$429,000
	Moisture Reduction/Compression	\$/each	\$710,000	1	1.6	\$1,107,600
	Siloxane Reduction	\$/each	\$300,000	1	1.6	\$468,000
	Equipment Subtotal					\$2,004,600
Rehab Existing	Allowance	%	0.0%	1	1.0	\$0
RNG Upgrading system		\$/each	\$2,400,000	2	1.2	\$5,760,000
Slab						
	Slab	\$/sf	\$63	400	1.0	\$25,084
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$25,084
	System Subtotal					\$7,789,684
Sitework	Sitework	%	5.0%			\$389,484
	Direct Cost Subtotal					\$8,179,169
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$8,179,169
Contractor Markup	Contractor Markup	%	37.4%			\$3,057,650
	Marked Up Subtotal					\$11,236,818
	Contingency	%	30.0%			\$3,371,045
	Contingent Subtotal					\$14,607,864
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$730,393
	Construction Cost Subtotal					\$15,338,257
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$3,681,182
	Project Delivery Cost Subtotal					\$19,019,438
Gresham Admin Fee						

	Option 3: Hybrid Approach + MHP					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Gresham Administration Charge	%	14.0%			\$2,662,721
	NWN Interconnection Charge	\$/each	\$2,500,000			\$2,500,000
CAPITAL COST						\$24,182,160

CHP

Demolition						
	Demolition Excluded					
Equipment Cost						
	600 kW Caterpillar w/o Enclosure	\$/each	\$1,075,000	1	1.6	\$1,677,000
	LCFS Compliance Costs	\$/each	\$45,000	0	1.6	\$0
	Biogas Storage Vessel	\$/each	\$405,000	1	1.6	\$648,000
	Equipment Subtotal					\$2,325,000
Slab						
	Slab	\$/sf	\$63	832	1.0	\$52,176
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$52,176
	System Subtotal					\$2,377,176
Sitework	Sitework	%	5.0%			\$118,859
	Direct Cost Subtotal					\$2,496,034
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$2,496,034
Contractor Markup	Contractor Markup	%	37.4%			\$933,102
	Marked Up Subtotal					\$3,429,136
	Contingency	%	30.0%			\$1,028,741
	Contingent Subtotal					\$4,457,877
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$222,894
	Construction Cost Subtotal					\$4,680,771
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$1,123,385
	Project Delivery Cost Subtotal					\$5,804,156
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$812,582
CAPITAL COST						\$6,616,738

Boiler

Demolition						
	Demolition Excluded					
Equipment Cost						
	Hot Water Boiler	\$/each	\$119,000	3	1.6	\$556,920
	Equipment Subtotal					\$556,920
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$556,920
Sitework	Sitework	%	43.0%			\$239,476
	Direct Cost Subtotal					\$796,396
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$796,396
Contractor Markup	Contractor Markup	%	37.4%			\$297,720
	Marked Up Subtotal					\$1,094,115
	Contingency	%	30.0%			\$328,235
	Contingent Subtotal					\$1,422,350
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$71,117
	Construction Cost Subtotal					\$1,493,467
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$358,432
	Project Delivery Cost Subtotal					\$1,851,899
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$259,266
CAPITAL COST						\$2,111,165

CAPITAL COST SUMMARY		
FOG and Food Waste Receiving Facility - New and Rehab Existing		\$2,856,282
Anaerobic Digester System - Convert Existing Tanks		\$11,871,282
Anaerobic Digester System - New Tank		\$29,430,440
Dewatering, Cake Conveyance, and Cake Storage		\$1,477,799
Gas Conditioning - New and Rehab Existing		\$24,182,160
CHP		\$6,616,738
Boiler		\$2,111,165
Grant Funding		\$0
Total Direct Cost		\$28,686,809
Total Project Cost		\$78,545,867

	Baseline Option (1 new MAD)					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
FOG and Food Waste Receiving Facility - New and Rehab Existing						
Demolition						
	Demolition Excluded					
Equipment Cost						
	Receiving Station Rock Trap	\$/each	\$10,000	0	1.6	\$0
	Receiving Station Grinder	\$/each	\$80,000	0	1.6	\$0
	Receiving Station Storage Tank	\$/each	\$39,000	1	1.6	\$60,840
	Receiving Station Unloading Pump	\$/each	\$70,000	0	1.6	\$0
	Receiving Station FOG Recirculation Pump	\$/each	\$20,000	1	1.6	\$31,200
	Receiving Station Mixer	\$/each	\$116,000	1	1.6	\$180,960
	Receiving Station Heat Exchanger	\$/each	\$100,000	0	1.6	\$0
	Receiving Station FOG Feed Pump	\$/each	\$30,000	0	1.6	\$0
	Receiving Station Hot Water Pressure Washer	\$/each	\$16,000	1	1.6	\$24,960
	Receiving Station Odor Control System	\$/each	\$225,000	1	1.6	\$351,000
	Equipment Subtotal					\$648,960
Existing FOG System Rehab (Allowance)		%	10.0%	1	1	\$64,896
Equipment Subtotal						\$713,856
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$713,856
Sitework	Sitework	%	5.0%			\$35,693
	Direct Cost Subtotal					\$749,549
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$749,549
Contractor Markup	Contractor Markup	%	37.4%			\$280,207
	Marked Up Subtotal					\$1,029,755
	Contingency	%	30.0%			\$308,927
	Contingent Subtotal					\$1,338,682
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$66,934
	Construction Cost Subtotal					\$1,405,616
Project Delivery						
	Engineering/Administration/Legal	%	24.0%			\$337,348
	Project Delivery Cost Subtotal					\$1,742,964
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$244,015
CAPITAL COST						\$1,986,979

Anaerobic Digester System - Convert Existing Tanks

Demolition						
	Demolition Included Below					
Equipment Cost						
	Convert Existing Tanks to Thermophilic					
	Digester Tank	\$/gal	\$2.22	0	1.6	\$0
	Mixing System	\$/each	\$100,000	0	1.6	\$0
	Mixing System -LMM Rehab	\$/each	\$292,000	0	1.6	\$0
	Heat Exchangers - Mesophilic	\$/each	\$45,000	0	1.6	\$0
	Heat Exchangers - Thermophilic	\$/each	\$70,000	0	1.6	\$0
	Solids Recirculation Pumps	\$/each	\$25,000	0	1.6	\$0
	Hot Water Recirculation Pumps	\$/each	\$10,000	0	1.6	\$0
	Digester Fixed Cover Replacement	\$/each	\$1,226,000	2	1.6	\$3,923,200
	Digested Solids Transfer Pumps	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$3,923,200
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$3,923,200
Sitework	Sitework	%	0%			\$0
	Demolition	%	2.0%			\$78,464
	Direct Cost Subtotal					\$4,001,664
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$4,001,664
Contractor Markup	Contractor Markup	%	37.4%			\$1,495,957
	Marked Up Subtotal					\$5,497,621
	Contingency	%	30.0%			\$1,649,286
	Contingent Subtotal					\$7,146,908
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$357,345
	Construction Cost Subtotal					\$7,504,253
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$1,801,021
	Project Delivery Cost Subtotal					\$9,305,274
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$1,302,738
CAPITAL COST						\$10,608,012

Anaerobic Digester System - New Tank

Demolition						
	Demolition Excluded					
Equipment Cost						
	Build New Thermophilic Tank					
	Digester Tank	\$/gal	\$2.44	1000000	1.0	\$2,440,000
	Mixing System	\$/each	\$405,000	1	1.6	\$631,800
	Heat Exchangers - Mesophilic	\$/each	\$45,000	1	1.6	\$70,200
	Heat Exchangers - Thermophilic	\$/each	\$70,000	0	1.6	\$0
	Solids Recirculation Pumps	\$/each	\$25,000	2	1.6	\$78,000
	Hot Water Recirculation Pumps	\$/each	\$10,000	2	1.6	\$31,200

	Baseline Option (1 new MAD)					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Digested Solids Transfer Pumps	\$/each	\$45,000	2	1.6	\$140,400
	Equipment Subtotal					\$3,391,600
Building						
	Building	\$/sf	\$400	2,500	1.0	\$1,000,000
	Odor Control	\$/scfm	\$65	1,875	1.0	\$121,875
	Buildings Subtotal					\$1,121,875
	System Subtotal					\$4,513,475
Sitework	Sitework	%	43.0%			\$1,940,794
	Direct Cost Subtotal					\$6,454,269
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$6,454,269
Contractor Markup	Contractor Markup	%	37.4%			\$2,412,824
	Marked Up Subtotal					\$8,867,093
	Contingency	%	30.0%			\$2,660,128
	Contingent Subtotal					\$11,527,221
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$576,361
	Construction Cost Subtotal					\$12,103,582
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$2,904,860
	Project Delivery Cost Subtotal					\$15,008,442
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$2,101,182
CAPITAL COST						\$17,109,624

Dewatering, Cake Conveyance, and Cake Storage

Demolition						
	Demolition Excluded					
Equipment Cost						
	Cake Storage	\$/cf	3.34	0	1.6	\$0
	Equipment Subtotal					\$0
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$0
Sitework	Sitework	%	20.0%			\$0
	Direct Cost Subtotal					\$0
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$0
Contractor Markup	Contractor Markup	%	37.4%			\$0
	Marked Up Subtotal					\$0
	Contingency	%	30.0%			\$0
	Contingent Subtotal					\$0
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$0
	Construction Cost Subtotal					\$0
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$0
	Project Delivery Cost Subtotal					\$0
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$0
CAPITAL COST						\$0

Gas Conditioning - New and Rehab Existing

Demolition						
	Demolition Excluded					
New Equipment Cost						
	H2S Reduction	\$/each	\$275,000	1	1.6	\$429,000
	Moisture Reduction/Compression	\$/each	\$710,000	0	1.6	\$0
	Siloxane Reduction	\$/each	\$300,000	1	1.6	\$468,000
	Equipment Subtotal					\$897,000
Rehab Existing	Allowance	%	20.0%	0	1.0	\$0
RNG Upgrading system		\$/each	\$ 2,275,000	0	1.6	\$0
Slab						
	Slab	\$/sf	\$63	400	1.0	\$25,084
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$25,084
	System Subtotal					\$922,084
Sitework	Sitework	%	10.0%			\$92,208
	Direct Cost Subtotal					\$1,014,293
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$1,014,293
Contractor Markup	Contractor Markup	%	37.4%			\$379,177
	Marked Up Subtotal					\$1,393,470
	Contingency	%	30.0%			\$418,041
	Contingent Subtotal					\$1,811,511
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$90,576
	Construction Cost Subtotal					\$1,902,086
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$456,501
	Project Delivery Cost Subtotal					\$2,358,587
Gresham Admin Fee						

	Baseline Option (1 new MAD)					
	Item	Unit	Unit Cost	Qty	Installation Factor	Cost
	Gresham Administration Charge	%	14.0%			\$330,202
CAPITAL COST						\$2,688,789

CHP

Demolition						
	Demolition Excluded					
Equipment Cost						
	600 kW Caterpillar w/ Enclosure	\$/each	\$1,175,000	0	1.6	\$0
	LCFS Compliance Costs	\$/each	\$45,000	0	1.6	\$0
	Equipment Subtotal					\$0
Slab						
	Slab	\$/sf	\$63	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$0
Sitework	Sitework	%	5.0%			\$0
	Direct Cost Subtotal					\$0
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$0
Contractor Markup	Contractor Markup	%	37.4%			\$0
	Marked Up Subtotal					\$0
	Contingency	%	30.0%			\$0
	Contingent Subtotal					\$0
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$0
	Construction Cost Subtotal					\$0
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$0
	Project Delivery Cost Subtotal					\$0
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$0
CAPITAL COST						\$0

Boiler

Demolition						
	Demolition Excluded					
Equipment Cost						
	Hot Water Boiler	\$/each	\$119,000	0	1.6	\$0
	Equipment Subtotal					\$0
Building						
	Building	\$/sf	\$400	0	1.0	\$0
	Odor Control	\$/scfm	\$65	0	1.0	\$0
	Buildings Subtotal					\$0
	System Subtotal					\$0
Sitework	Sitework	%	43.0%			\$0
	Direct Cost Subtotal					\$0
	Project Tax Rate	%	0.0%			\$0
	Taxed Subtotal					\$0
Contractor Markup	Contractor Markup	%	37.4%			\$0
	Marked Up Subtotal					\$0
	Contingency	%	30.0%			\$0
	Contingent Subtotal					\$0
Construction Cost	Escalation	%/yr	0.0%	0		\$0
	Market Adjustment Factor	%	5.0%			\$0
	Construction Cost Subtotal					\$0
Project Delivery						
	Engineering/Administration/legal	%	24.0%			\$0
	Project Delivery Cost Subtotal					\$0
Gresham Admin Fee						
	Gresham Administration Charge	%	14.0%			\$0
CAPITAL COST						\$0

CAPITAL COST SUMMARY		
FOG and Food Waste Receiving Facility - New and Rehab Existing		\$1,986,979
Anaerobic Digester System - Convert Existing Tanks		\$10,608,012
Anaerobic Digester System - New Tank		\$17,109,624
Dewatering, Cake Conveyance, and Cake Storage		\$0
Gas Conditioning - New and Rehab Existing		\$2,688,789
CHP		\$0
Boiler		\$0
Grant Funding		\$0
Total Direct Cost		\$12,219,775
Total Project Cost		\$32,393,404

Appendix D. Renewable Energy Market Assessment

Included in Appendix A-3

WWTP Anaerobic Digestion and Cogeneration Expansion Project – Potential Capital Funding Sources

Date:	December 8, 2022	Jacobs Engineering Group Inc.
Project name:	Gresham Wastewater Project	2020 SW Fourth Avenue
Attention:	Rob Chapler	3rd Floor
Client:	City of Gresham	Portland, OR 97201
Prepared by:	Kristen Jackson and Bashar Al-Daomi	United States
Reviewed by:	Matt Noesen and Kurt Playstead	T +1.503.235.5000
Copies to:	Project files	www.jacobs.com

Background/Introduction

The City of Gresham (City) owns an activated sludge Wastewater Treatment Plant (WWTP) which discharges treated effluent to the Columbia River under NPDES permit number 102523 which was issued on September 22, 2021 and expires on August 31, 2026. The average dry weather design flow is 15 mgd and the average wet weather design flow is 25 mgd. The WWTP is divided into two influent treatment trains – the Upper Plant and the Lower Plant. The Upper Plant generally receives approximately 60 percent of the influent flow, with the Lower Plant receiving the remaining 40 percent. Both trains treat influent wastewater using a combination of screening, grit removal, primary clarification, biological treatment with activated sludge, and chlorination/de-chlorination. Solids generated in the primary and secondary processes are treated using gravity belt thickeners, anaerobic digestion and dewatering belt filter presses prior to being hauled offsite for land application of Class B biosolids on farmland in various locations in the Oregon.

Through multiple energy efficiency and renewable energy generation efforts, the City' WWTP attained energy neutrality or Net Zero status in 2015, the first of its kind in the Pacific Northwest. At the center of the Net Zero approach is accepting fats, oils, and grease (FOG) and co-digesting that materials with the municipal solids generated by the WWTP to generate more biogas and in turn more renewable electricity.

However, even with these improvements, the City must turn away FOG haulers. And the City is potentially interested in the food scraps recovery program Metro is developing over the next couple of years. The City could process this high strength food slurry from Metro's program for conversion into more renewable energy if there were additional high-strength waste receiving, digestion, and cogeneration capabilities and capacity.

The results of a 2020 Feasibility Study of Expanding Liquid Organic Digestion Capacity concluded that a possible business case exists for investing in the needed infrastructure to produce excess renewable energy. By increasing liquid organic waste receiving capacity at the WWTP, turning the waste into energy with a cogeneration expansion, and feeding that electricity back onto the grid to power electrical vehicles, Gresham WWTP stands to be the first of its kind again by going Beyond Net Zero.

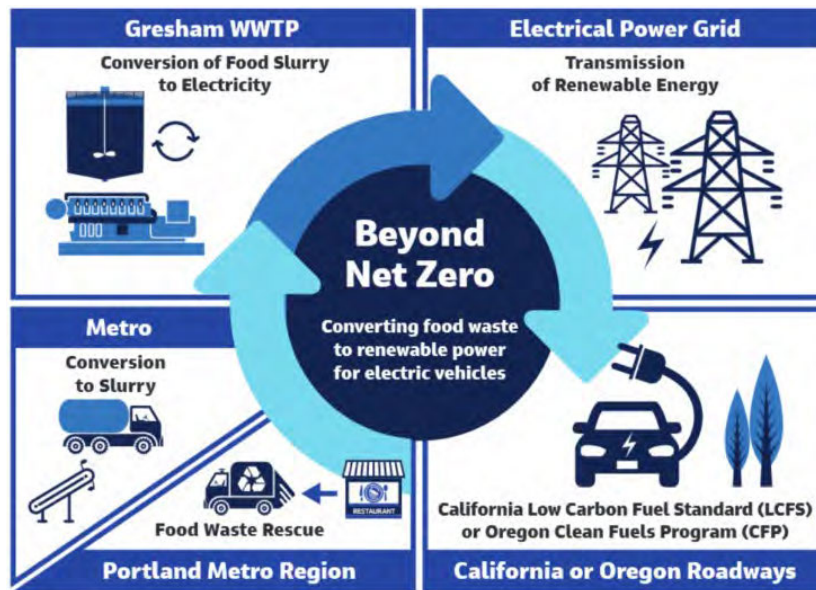


Exhibit 1: From 2020 Feasibility Study with Jacobs

The purpose of this memorandum is to identify potential funding options for the City of Gresham to consider as they develop this project to a predesign level.

1. Financing Options

This memorandum summarizes potential financing sources available to the City from state and federal agencies as well as private financing. The memo briefly describes each program, including interest rates, fees, and other requirements where available, and provides eligibility criteria when applicable. A general overview of the potential funding programs is provided.

Interest rates and terms for the different funding programs presented herein are as of June 2022 and are subject to changing market and regulatory conditions.

1.1 Business Oregon: Infrastructure Funding Agency

Business Oregon is the state's economic development agency. The agency provides businesses and local communities access to infrastructure and business development services, including funding programs. Business Oregon will work with eligible applicants to secure the best financing package available. The agency may schedule a "one-stop" meeting with the applicant to help identify potential financing sources from state and federal agencies. Two programs administered by Business Oregon that would likely be available to the City are the Water/Wastewater Fund and the Special Public Works Fund.

1.1.1 Water/Wastewater Financing Program (w/w)

Business Oregon, through its Infrastructure Funding Agency (IFA), administers the Water/Wastewater Fund to provide funding for design and construction of public infrastructure needed to ensure compliance with the Safe Drinking Water Act or the Clean Water Act. The Water/Wastewater Fund is open to the following public entities: cities, counties, county service districts (organized under ORS Chapter 451), tribes, ports, and special districts (as defined in ORS 198.010). Municipally owned wastewater systems are eligible for funding.

Eligible activities include reasonable costs for construction improvement or expansion of drinking water, wastewater, or storm water systems. To be eligible, a system must have received, or is likely to soon

receive, a Notice of Non-Compliance (NON) by the appropriate regulatory agency, associated with the Safe Drinking Water Act or the Clean Water Act. Projects also must meet other state or federal water quality statutes and standards. Eligible activities include wastewater collection and capacity improvements or expansion, purchase of rights of way and easements necessary for construction, and design and construction engineering. Planning/technical assistance for small communities.

Low interest loans up to \$10 million, are available for design and construction. The loans have a 30-year maximum term. OBDD is able to offer interest rates that reflect tax exempt, market rates. Loans are generally repaid with utility revenues. Applications are accepted year-round. To begin the process, a Project Notification and Intake form will need to be completed.

The program provides grant awards up to \$750,000 based on financial review. An applicant is not eligible for grant funds if their annual median household income is greater than or equal to 100 percent of the state average median household income for the same year.

Because this project is not associated with a NON from the Oregon Department of Environmental Quality, the City would most likely not qualify for this Program.

1.1.2 Special Public Works Fund (SPWF)

Business Oregon also administers the Special Public Works Fund to provide low-cost financing to eligible municipalities for planning, design, and construction of utilities and facilities that support economic and community development. Interest rates, terms, and issuance costs are the same as the Water/Wastewater Fund. The Special Public Works Fund is open to the following public entities: cities, counties, county service districts (organized under ORS Chapter 451), tribes, ports, and districts (as defined in ORS 198.010). Municipally owned wastewater systems are eligible for funding.

Low interest loans up to \$10 million with terms of 25 years, are available for design and construction. The program offers interest rates that reflect tax exempt, market rates. Applications are accepted year-round based on funding availability. Applicants must submit a completed application to Business Oregon.

1.2 Oregon Department of Environmental Quality (ODEQ)

1.2.1 Clean Water State Revolving Fund (CWSRF)

The Clean Water State Revolving Fund (CWSRF) provides low interest loans for the planning, design, and construction of water pollution control projects. The program is administered by the Oregon Department of Environmental Quality (ODEQ). Any public agency, including cities, counties, tribes, sanitary districts, irrigation districts, and special districts, is eligible for funding. Low interest loans that are below market interest rates are available with terms up to 30 years. Different interest rates and other financial terms apply to different types of loans and to loans of differing repayment periods. Once a loan is signed, the interest rate is fixed for the life of the loan. One hundred percent of the eligible costs are covered. Repayments begin after the project is constructed.

A wide range of water infrastructure projects are eligible to receive CWSRF assistance including:

- Construction of publicly owned treatment works (POTWs),
- Nonpoint source infrastructure,
- National estuary program projects,
- Decentralized wastewater treatment systems,
- Stormwater,
- Water conservation & efficiency,
- Watershed pilot projects,
- Energy efficiency,
- Water reuse, and
- Security measures.

Applications are accepted year-round with scheduled review and ranking in the first week of January, May, and September. An application that provides information on the need, environmental benefits, and cost estimates of each project is submitted to DEQ. All projects are ranked based on specific ranking criteria developed by DEQ. There will be a significant infusion of new Federal funding into the SRF programs each year during the next five years as a result of funds being made available through the Bipartisan Infrastructure Law (BIL). For FY 2022, Oregon is receiving \$20.1 M in new Federal funding for its clean water SRF program as a result of the BIL, plus roughly an additional \$1 M to address clean water issues associated with emerging contaminants. Typically, in the past ODEQ's policy has been that any local wastewater utility wanting to utilize these funds must have a Facility Plan that has been reviewed and approved by ODEQ staff.

1.3 Oregon Department of Energy (ODOE)

1.3.1 Community Renewable Energy Grant Program (CREP)

The Community Renewable Energy Grant Program (CREP) is open to Oregon Tribes, public bodies, and consumer-owned utilities. The program is administered by the Oregon Department of Energy (ODOE). Public bodies include counties, municipalities, and special government bodies such as ports and irrigation districts. Grants are awarded on a competitive basis and priority will be given to projects that support program equity goals, demonstrate community energy resilience, and include energy efficiency and demand response. At least half of the grant funds will be awarded for projects that serve environmental justice communities, including communities of color, lower-income communities, rural communities, and others. Similarly, at least half of the grant funds will be awarded to projects that support community energy resilience. Eligible projects include renewable energy generation systems like solar or wind, and energy storage systems, electric vehicle charging stations, or microgrid technologies paired with new or existing renewable energy systems.

For Planning a community energy resilience project or planning a community renewable energy project, the maximum award is \$100,000 with 100% of maximum percent of eligible project costs. The maximum award for the construction phase of a community renewable energy project is \$1,000,000 and up to 50% of the eligible project cost.

Applications are announced in March and due by July.

1.3.2 Energy Infrastructure Reinvestment Loan Program - \$250 billion in loan authority

- Description: Funds projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations, or enable operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutions and greenhouse gas emissions.
- Status: The DOE Loan Program Office plans to provide initial implementing guidance and collect public comment on program design within the coming months.
- Recommendation: If the project qualifies as "energy infrastructure" by virtue of its current renewable electricity generation, this program would be worth pursuing by making a case that you're "retooling energy infrastructure."

1.3.3 Innovative Clean Energy Loan Guarantees - \$40 billion in loan authority

- Description: Funds clean energy projects, including renewable energy, that avoids or reduces greenhouse gas emissions, employs a new or significantly improved technology as compared to commercially available technology, and provides a reasonable prospect of repayment of the principal and interest.
 - A new or significantly improved technology means a technology concerned with the production, consumption, or transportation of energy that has either only recently been

- developed or discovered; or involves one or more meaningful improvements in productivity or value in comparison to commercial technologies.
- A loan guarantee may not exceed 80% of the project cost, and the fees are traditionally 1% for the portion of the principal amount.
- Applicants are encouraged to have a consultation with the DOE Loan Program Office to discuss the project and learn about the process before applying.
- Link to Current Solicitation: https://www.energy.gov/sites/default/files/2022-04/DOE-LPO_Innovative_Clean_Energy_Loan_Guarantee_Solicitation_18Apr22.pdf
- Link to Eligibility Guide: https://www.energy.gov/sites/default/files/2022-05/LPO_Technical_Eligibility_Guide_Title17-Innovative_Clean_Energy_May2022.pdf
- Recommendation: If the project successfully qualifies as a new or significantly improved technology that is not commercially available, this program is worth pursuing. If the microbial hydrolysis Process (MHP) is incorporated into the Gresham project, then this program might be applicable.

1.4 Environmental Protection Agency (EPA)

1.4.1 Water Infrastructure Finance and Innovation Act (WIFIA)

The Water Infrastructure Finance and Innovation Act of 2014 (WIFIA) established the WIFIA program, a federal credit program administered by EPA for eligible water and wastewater infrastructure projects. Any public agency, including local, state, tribal, and federal government entities, partnerships, and joint ventures, corporations and trusts, Clean Water and Drinking Water State Revolving Fund (SRF) programs, is eligible for funding. The WIFIA program can fund development and implementation activities for eligible projects such as:

- Projects that are eligible for the Clean Water SRF,
- Notwithstanding the public ownership clause,
- Projects that are eligible for the Drinking Water SRF,
- Enhanced energy efficiency projects at drinking water and wastewater facilities.

Eligible development and implementation activities are:

- Development phase activities, including planning, preliminary engineering, design, environmental review, revenue forecasting, and other pre-construction activities,
- Construction, reconstruction, rehabilitation, and replacement activities,
- Acquisition of real property or an interest in real property, environmental mitigation, construction contingencies, and acquisition of equipment,
- Capitalized interest necessary to meet market requirements, reasonably required reserve funds, capital issuance expenses and other carrying costs during construction.

Low interest loans are available for design and construction for minimum project size of \$20 million for large communities. For small communities, (population of 25,000 or less), the minimum project size is \$5 million. The maximum portion of eligible project costs that WIFIA can fund is 49 percent. The other 51 percent must come from other sources such as reserves, municipal bonds, or SRF loans. The loans have a 35-year maximum term. Repayment can be deferred up to 5 years after substantial completion of the project. Projects must be creditworthy and have a dedicated source of revenue. A prospective borrower should submit a complete application within one year of invitation to apply for due diligence to begin.

1.4.2 Greenhouse Gas Reduction Fund - \$27 billion

- Description: To support competitive grants to national and local “green banks,” which will use the money to invest in projects and innovations for clean energy and climate projects that reduce or avoid greenhouse gas emissions and other forms of air pollution.
- Eligible Entities: Nonprofit organizations that leverage private capital and other forms of financial assistance to rapidly deploy low- and zero-emission products, technologies, and services.
- Status: EPA is undergoing a stakeholder engagement strategy, including public listening sessions, a public comment period (which ended on Dec. 5th), and expert review and recommendations by the Environmental Finance Advisory Board. Funding opportunity likely to open Feb. 2023.
- Recommendation: City of Gresham partners with local non-profits to develop financing plans to increase liquid organic waste receiving capacity at the WWTP.

1.4.3 Climate Pollution Reduction Grants - \$5 billion

- Description: To assist States and localities in developing and implementing strong, climate pollution reduction strategies. EPA will make grants to at least one eligible entity in each State to develop a plan for reducing greenhouse gas air pollution, and then EPA will competitively award grants to eligible entities to implement those plans.
- Eligible Entities: States, air pollution control agencies, tribes and local governments.
- Status: EPA released a Request for Information on November 10, 2022 and this new program will be informed by comments, in addition to other stakeholder engagement activities. Funding opportunity likely to open in Spring 2023.
- Recommendation: City of Gresham applies for funding develop a greenhouse gas air pollution reduction plan to include expanding liquid organic digestion capacity, and then apply for grants to implement this project.

1.4.4 Environmental and Climate Justice Block Grants - \$3 billion

- Description: EPA shall award grants for periods of up to 3 years for the following activities that benefit disadvantaged communities:
 - Community-led air and other pollution monitoring, prevention, and remediation, and investments in low- and zero-emission and resilient technologies and related infrastructure and workforce development that help reduce greenhouse gas emissions and other air pollutants.
 - Mitigating climate and health risks from urban heat islands, extreme heat, wood heater emissions, and wildfire events.
 - Climate resiliency and adaptation.
 - Reducing indoor toxics and indoor air pollution.
 - Facilitating engagement of disadvantaged communities in State and Federal advisory groups, workshops, rulemakings, and other public processes.
- Eligible Entities: A partnership between:
 - An Indian tribe, a local government, or an institution of higher education; AND a community-based nonprofit organization.
 - A community-based nonprofit organization.
 - A partnership of community-based nonprofit organizations.

- Status: EPA established a new national office titled “Office of Environmental Justice and External Civil Rights” to oversee implementation of this program and enhance EPA’s ability to infuse equity, civils rights, and environmental justice principles into EPA policies and programs. Funding opportunity likely to open in Spring 2023.
- Recommendation: City of Gresham partners with a local, community-based non-profit organization to apply and implement funding for zero-emission technologies that reduce greenhouse gas emissions.

1.4.5 Low-Emissions Electricity Program - \$87 million

- Description: To fund a wide range of activities to encourage low emissions electricity generation through education, technical assistance, and partnerships with consumers, low income and disadvantaged communities, industry, and state, local, and Tribal governments.
- Eligible Entities: EPA
- Status: EPA released a Request for Information on November 10, 2022 and this new program will be informed by comments, in addition to other stakeholder engagement activities. Funding opportunity likely to open in Spring 2023.
- Recommendation: This program is not applicable.

1.5 Portland General Electric (PGE)

1.5.1 Renewable Development Fund (RDF)

Through the RDF, PGE provides opportunities for applicants to receive financial support to help advance the construction of qualifying new non-residential renewable energy projects.

The RDF program can fund development and implementation activities for eligible projects fall into one or more of these categories:

- Wind, solar photovoltaic, geothermal, low impact hydroelectric, pipeline or irrigation canal hydroelectric, wave or tidal energy and low emissions biomass based on digester methane gas or solid organic fuels.
- Research and development projects that facilitate renewable energy market transformation or the emergence of new renewable technologies.
- Projects that are eligible for the Drinking Water SRF,
- Educational components directly associated with an RDF funded renewables project.

Interested parties can access the 2022 application starting April 1, 2022. The submittal deadline is June 1, 2022.

1.6 Municipal Revenue Bonds

The utility could issue revenue bonds through the traditional bond market to construct the project. Revenue bonds would be secured by the revenues of the wastewater utility. Typically, bonds have a 20-year term and an interest rate of around 4-5 percent for public agencies. A bond issuance fee of 1-2 percent will also be incurred. Depending on the final terms included in the bond covenants, the wastewater system may also have to establish a reserve fund equal to one annual debt service payment.

1.6.1 Private Financing

If the utility was unable to secure funding from a state or federal agency, it could partner with a private entity for funding. Several private equity investment organizations and groups have shown increased

interest in providing financing for capital projects in the water and wastewater industries. The size of the project would determine the level of interest from private investors. The interest rate for capital equity financing is likely to be noticeably higher than for municipal bond financing. This is because the sources of money available to private equity firms typically have higher interest rates (taxable rates) than tax-exempt options available to municipal borrowers, and the return that private equity firms need to show for their equity investments in transactions such as this one is typically higher than municipal borrowing rates. Private financing is often combined as part of a broader form of collaborative delivery, such as a long-term concession in which a private team provides capital for construction, delivers the capital project, and then operates the facility for an extended period. Such collaborative forms of delivery can often provide operational and other cost savings that can offset the higher cost of capital for private financing. A value for money comparison of traditional delivery and finance compared with collaborative delivery and finance is typically required to determine if there is a value proposition for the stakeholders of a system like Gresham's in such an arrangement.

Another form of private finance that can be considered is privately raised capital to test new approaches and technologies, such as environmental impact bonds (EIBs) that have been organized to fund green and new technologies by several agencies throughout the United States. An EIB is a form of 'pay for success' in which investors agree to take a lower rate of return if the new/emerging technology or technique underperforms compared with an agreed upon level of performance but receive a bonus payment if the new approaches/technologies over perform compared with an agreed-upon expected performance level. This form of private finance could be considered if there are innovative aspects to either the technologies or delivery approaches planned for the Gresham facilities.

1.7 State of Oregon

1.7.1 Energy Trust of Oregon

As a result of state legislation, tariffs and other requirements, Energy Trust is funded by customers of Portland General Electric, Pacific Power, NW Natural, Cascade Natural Gas and Avista. Customers of these five utilities pay a small, dedicated percentage of their utility bills to support a variety of energy-efficiency and renewable energy services and programs in Oregon and Southwest Washington. Through Energy Trust of Oregon, the state of Oregon provides opportunities for applicants to receive financial support for renewable energy projects through Energy Trust, an independent, third party approved by the OPUC in 2001.

1.8 Inflation Reduction Act (IRA) Programs and Tax Credits

1.8.1 Renewable Energy Generation Tax Credits

Note: The IRA made the following tax credits eligible to receive direct payment in lieu of a reduction in tax liability (direct pay). For tax years beginning after December 31, 2022, and before January 1, 2033, tax-exempt entities, State and local governments, and Indian tribal governments may elect to treat certain tax credits as refundable payments of tax.

Status: The Department of Treasury is currently requesting public input on new clean energy tax incentives: <https://home.treasury.gov/news/press-releases/jy0993>

- Extension of Section 45 Renewable Electricity Production Tax Credit (PTC)
 - Description: The IRA extends the PTC for facilities that begin construction by the end of 2024 and provides a credit of 1.5 cents per KWh (\$27.50 per MWh), adjusted for inflation and subject to certain wage and apprenticeship requirements, and includes bonus credits if the facility meets domestic content requirements or if the facility is placed in service in an "energy community".

- Eligible Facilities: geothermal, wind, closed- and open-loop biomass, landfill gas, municipal solid waste, hydropower, solar, and marine and hydrokinetic facilities
- **NEW: Section 45Y technology-neutral production tax credit**
 - Description: This new PTC replaces the above Renewable Electricity PTC once it phases out at the end of 2024. The new PTC credit of 1.5 cents per kWh of electricity produced and sold or stored at facilities placed into service after 2024 with zero or negative GHG emissions, subject to certain wage and apprenticeship requirements with bonus credits if the facility meets domestic content requirements or if the facility is placed in service in an “energy community”.
 - Taxpayers may choose either the 45Y PTC or the Section 48E ITC (see below)
 - Credits begin to phase out for projects that start construction after 2033 or after certain emissions targets are achieved (such as when the electric power sector emits 75% less carbon than 2022 levels).
- **Extension of Section 48 Energy Investment Tax Credit (ITC)**
 - Description: The IRA extends the ITC until 2024 for solar energy property, geothermal property, fiber-optic solar property, fuel cell property, microturbine property, small wind property, offshore wind property, combined heat and power property, and waste energy recovery property constructed before January 1, 2025.
 - Creates additional credit for energy storage technology.
 - In general, for energy property placed in service by the end of 2024, the IRA restores the credit to 30% of the cost basis, subject to specific wage and apprenticeship requirements, and includes bonus credit if the facility meets domestic content requirements or if the facility is placed in service in an “energy community”.
- **NEW: Section 48E technology-neutral investment tax credit**
 - Description: This new ITC replaces the above Energy ITC once it phases out at the end of 2024. **The new ITC creates a 30% credit for power facilities of any technology type if the facility’s carbon emissions are at or below zero.** Projects are subject to specific wage and apprenticeship requirements, and the new ITC includes bonus credit if the facility meets domestic content requirements or if the facility is placed in service in an “energy community”.
 - Credits begin to phase out for projects that start construction after 2033 or after certain emissions targets are achieved (such as when the electric power sector emits 75% less carbon than 2022 levels).
 - Recommendation: **This program could be the most significant for the City of Gresham’s Digester & Cogen project.** The City should track closely and consider commenting participating in the Department of Treasury public input process on new clean energy tax incentives: <https://home.treasury.gov/news/press-releases/jy0993>

Table 1. Summary of the Most Promising State and Federal Funding Programs For Capital/Project Construction Costs for the City of Gresham WWTP Anaerobic Digestion and Cogeneration Expansion

Program	Eligible Projects	Who can apply	Funding Availability	Terms/Interest Rate	Local Match Required	Other
Water/Wastewater Financing Program (w/w) under Business Oregon: Infrastructure Funding Agency	Reasonable costs for construction improvement or expansion of drinking water, wastewater, or storm water systems	cities, counties, county service districts, tribes, ports, and special districts	\$10 million for design and construction	Construction loan: •Term typically 30 years •Follows market rate; Subsidized rates may be available depending on community affordability rate	No	Applications are accepted year-round. To begin the process, a Project Notification and Intake form will need to be completed.
Special Public Works Fund (SPWF) under Business Oregon	Planning, design, and construction of utilities and facilities that support economic and community development.	cities, counties, county service districts, tribes, ports, and special districts	\$10 million for design and construction	Construction loan: •Term typically 25 years •Follows market rate; Levees: 0%, max \$1 million and cap 50% of loan and market rate remaining; Planning: 50% of set rate	None	Applications are accepted year-round based on funding availability. Applicants must submit a completed application to Business Oregon.
Community Renewable Energy Grant Program (CREP) under Oregon Department of Energy (ODOE)	Projects that support program equity goals, demonstrate community energy resilience, and include energy efficiency and demand response.	Oregon Tribes, public bodies, and consumer-owned utilities. counties, municipalities, and special government bodies such as ports and irrigation districts.	Up to \$100,000 with 100% of maximum percent of eligible project costs (Planning a community energy resilience project or planning a community renewable energy project) Up to \$1000,000 for Constructing a community renewable energy project with up to 50% of eligible project cost. Construction a community energy	Grant program	No	Applications are announced in March and due in July.

Technical Memorandum

Program	Eligible Projects	Who can apply	Funding Availability	Terms/Interest Rate	Local Match Required	Other
			resilience project or planning a community renewable energy project			
Water Infrastructure Finance and Innovation Act (WIFIA) under Environmental Protection Agency (EPA)	Development phase activities, including planning, preliminary engineering, design, environmental review, revenue forecasting, and other pre-construction activities, Construction, reconstruction, rehabilitation, and replacement activities	Local, state, tribal, and federal government entities, partnerships, and joint ventures, corporations and trusts, Clean Water and Drinking Water State Revolving Fund (SRF) programs	Large communities have a minimum projects size of \$20 million for design and construction. For small communities (population of 25,000 or less), the minimum project size is \$5 . 49 percent is the maximum portion of eligible project costs that WIFIA can fund.	Construction loan: <ul style="list-style-type: none"> • Flexible terms, often up to 35 years. 5 years-maximum time that repayment may be deferred after substantial completion of the project. • 1.89 percent interest rate 	No	Projects must be creditworthy and have a dedicated source of revenue. A prospective borrower should submit a complete application within one year of invitation to apply for due diligence to begin. A prospective borrower should submit a complete application within one year of invitation to apply for due diligence to begin.
Renewable Development Fund (RDF) under Portland General Electric (PGE)	Fall into one or more of these categories: including Wind, solar photovoltaic, geothermal, low impact hydroelectric, pipeline or irrigation canal hydroelectric, wave or tidal energy and low emissions biomass based on <u>digester methane gas</u> or solid organic fuels.	Customer located withing PGE service area; preference given to public entity	Up to 85% can be provided by outside sources (e.g., RDF, ETO and ODOE, etc.); minimum 15% must be funded by applicant.	Grant program	Yes, see funding availability.	Application starts April 1, 2022. The submittal deadline is June 1, 2022.

Technical Memorandum

Program	Eligible Projects	Who can apply	Funding Availability	Terms/Interest Rate	Local Match Required	Other
Energy Trust of Oregon under State of Oregon	Renewable energy projects for customers located in applicable service areas including PGE	WWTPs with anaerobic digestions if located within applicable service area (Gresham qualifies – PGE is electrical power provider)	To be determined on a project specific basis; ETO pays for the incremental project costs above the market rate	Grant program	Yes, by definition	
Inflation Reduction Act Programs and Tax Credits	Solar energy property, geothermal property, fiber-optic solar property, fuel cell property, microturbine property, small wind property, offshore wind property, combined heat and power property, and waste energy recovery property	Tax-exempt entities, State and local governments, and Indian tribal governments may elect to treat certain tax credits as refundable payments of tax	Section 48E: The new ITC creates a 30% credit for power facilities of any technology type if the facility's carbon emissions are at or below zero.	Tax credit	No	Much of the IRA is still waiting to be implemented, the City should track closely.

Appendix B

Discipline Technical Memorandums

Architectural

Corrosion Control

Electrical

Geotechnical

Heating, Ventilation, and Air Conditioning; Plumbing; Fire Protection

Instrumentation and Controls

Mechanical

Site Civil and Yard Piping

Structural

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Subject	Architectural
Project Name	City of Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project
Jacobs Project Number	D3621900
To	Rob Chapler/City of Gresham
From	Steve Hockman
Reviewed by	Benjamin Herman
Date	March 7, 2023

1. Introduction

The purpose of this technical memorandum is to generally define the architectural design for the process facilities at Gresham Wastewater Treatment Plant (WWTP) Anaerobic Digestion and Cogeneration Expansion in the City of Gresham. The architectural intent is to provide functional buildings and structures that present an image of quality and good design while using durable, low-maintenance, and corrosion-resistant materials. The new buildings and structures will be designed to complement and/or match the campus-wide architecture at the existing site. The preliminary architectural scope assumptions (**in bold**) are as follows (scoping may change upon further discovery and analysis):

General structures/facilities:

- 08- Microgrid:
 - Description: Install microgrid power controls for use during utility power outages so that WWTP system can be isolated from the PGE utility grid.
 - Architectural Scope: NONE.
- 10- FOG (Fats Oils Grease) Receiving:
 - Description: Receiving expansion.
 - Architectural Scope: NONE.
- 15- FWS (Food Waste Slurry) Receiving:
 - Description: New Receiving Facility.
 - Architectural Scope: NONE.
- 20- Existing digester control building upgrade:
 - Description: **Address architectural components associated with retrofitting existing openings in existing roof and walls to comply with NFPA 820 (National Fire Protection Association) guidelines and as related to heating, ventilation, and air conditioning (HVAC) upgrades.**

- **Architectural Scope: YES.**
- **30- Existing Digester Upgrades.**
 - Description: Convert exist mesophilic digester to thermophilic digester operation.
 - Architectural Scope: NONE.
- **40- Digester 3 control building - New:**
 - Description: Two-level structure with daylight basement due to slope in grade.
 - Architectural Scope: YES.
- **50- Digester 3 - New:**
 - Description: Thermophilic Digester.
 - Architectural Scope: YES.
- **60- Gas Conditioning and Cogeneration Facility - New:**
 - Description: Separate rooms for each cogeneration engine for sound isolation. Includes electrical room and control room.
 - Architectural Scope: YES.
- **65 – Gas Storage - New:**
 - Description: Gas storage bubble.
 - Architectural Scope: NONE.
- **90- Biosolids Storage Facility Expansion - New:**
 - Description: Doubling the biosolids processing capacity. Includes extending open-air roof cover (Glulam beams and girders):
 - Fire Apparatus access may be limited. To be further explored with jurisdiction with regards to existing open-air wood structure.
 - Existing facility would require retrofit to allow vehicular access between new and existing facilities.
 - Architectural Scope: YES.

2. Applicable Codes, Standards, And Regulations

Currently adopted building codes by City Of Gresham are:

- 2022 Oregon Fire Code (OFC)
- 2022 Oregon Structural Special Code (OSSC)
- 2021 Oregon Energy Efficiency Special Code (OEESC)
- 2021 Oregon Electrical Specialty Code (OESC)
- 2022 Oregon Mechanical Specialty Code (OMSC)
- 2021 Oregon Plumbing Specialty Code (OPSC)

Further code investigation required:

- The recent code adoption of the 2022 OSSC may require significant code or seismic upgrades to existing facilities. If, during further code analysis, there is a discovery of an upgrade, further investigation may be required to determine design and/or cost impacts.

Building code data tables:

- A code analysis will be performed for each applicable building, based on occupancy and construction materials, including fire separation distance analysis. The code analysis will be updated throughout the design process and essential code data will be included on the architectural drawings in the Contract Documents. Preliminary data are documented in the Tables 1 through 4 below.

Table 1. 20 Existing Digester Control Building

Code Requirement	Specific Building Requirement
Construction classification	To be determined/verified
Occupancy classification	Moderate-Hazard Factory Industrial, Group F-1 (International Building Code [IBC] 306.2)

Table 2. 60 New Cogeneration Building

Code Requirement	Specific Building Requirement
Construction classification	Type IIB (602.2) or VB (IBC 602.5) – To be determined
Occupancy classification	Moderate-Hazard Factory Industrial, Group F-1 (IBC 306.2)

Table 3. 70 New Waste Gas Burner Screen or Canopy

Code Requirement	Specific Building Requirement
Construction classification	Type IIB (602.2) or VB (IBC 602.5) – To be determined
Occupancy classification	To be determined

Table 4. 90 New Biosolids Storage Facility

Code Requirement	Specific Building Requirement
Construction classification	Type VB (IBC 602.5).
Occupancy classification	Moderate-Hazard Factory Industrial, Group F-1 (IBC 306.2)

Energy code/Oregon State requirements:

- Zone: Western Oregon Zone 4C Mixed Marine

Accessibility:

- Process and equipment spaces frequented only by service personnel are not required to be accessible (refer to OSSC Chapter 11, Section 1103.2.9).
- It is assumed that public tours will not be conducted onsite:

- If public tours are desired at new (or existing) process structures, the tour route will need to meet Americans with Disabilities Act (ADA) requirements for those interior and exterior accessible areas. Public tour routes require early programming to ensure that all ADA requirements are incorporated in the planned roadways, sidewalks, and buildings or structures with regards to items including, but not limited to, pavement/sidewalk slopes, curb cuts, ramps, stairs, landings, and handrail design.

Fire suppression provisions:

- An automatic fire sprinkler system is not required for F-1 buildings that do not exceed 12,000 square feet (reference IBC Chapter Section 903.2.4). Fire extinguishers will be stationed in compliance with code requirements and will be generally located at main points of egress.

Sanitary and safety provisions:

- Plumbing fixtures shall be provided per table 2902.1 based on actual use of the building or space. Uses not shown in the table shall be considered individually by the code official.
- Required public and employee toilet facilities shall be located not more than one story above or below the space required to be provided with toilet facilities. The path of travel to such facilities shall not exceed 500 feet (reference IBC Chapter 29, Section 2902.3.3)
 - Exception 2: Location and maximum distances of travel to required employee areas in factory and industrial occupancies can exceed requirement if approved by local jurisdiction via a waiver process.

3. Design Criteria

3.1 Major Exterior Systems

Generally, exterior materials and finishes will be selected for low maintenance and corrosion resistance. Additionally, exterior envelope components will be evaluated and selected for energy performance in conjunction with energy code requirements. Major components have been investigated as follows:

- Roofs: Similar profile and/ or materials to complement existing facilities on campus while meeting current building codes – possible thermoplastic polyolefin membrane system.
 - Special consideration is being explored to replicate the open-air roof cover of the existing Biosolids Storage Facility, including Glulam beams and girders, at building 90 (New Biosolids Storage Facility).
 - Access by fixed ladders and roof hatches will be provided where mechanical equipment is located on building roofs.
- Walls:
 - Similar profile and/or materials to complement existing facilities on campus while meeting current building codes: Low profile concrete base, red brick veneer, topped with a ribbed green, metal panel cap.
 - Parapet walls will be extended to guard height for operator protection and may be extended to visually screen any rooftop equipment (to be verified with planning department).
- Translucent wall and/or roof panels may be explored for natural light opportunities – to be determined.

- Doors and Frames: Steel hollow metal with galvanized coating, factory primer, and field painted. Primary building entrances may have glazed aluminum storefront with factory finish. Other doors and frames may include wood or fiberglass applications.
- Door Hardware: Heavy-duty mortise type; stainless steel. Panic devices at electrical room doors and doors at hazardous occupancies. Electronic Security Access control will need to be verified with operations early in the design – to be determined.
- Overhead Doors: Galvanized steel with polyvinylidene fluoride factory finish. Operation to be motorized.
- Windows: Aluminum thermally broken frames with double-pane insulated glass having Low-E coating.
- Louvers: Drainable blade type with bird screen, aluminum with factory finish. Sound attenuating louvers may be used at high noise spaces as required.
- Waterproofing: Below grade walls of habitable spaces will receive fluid—applied waterproofing and protection board.
- Under slab vapor retarder will be provided to concrete slabs with chemical resistant coating as scheduled.
- Signage: Safety, informational, and hazardous material signs will be provided as required by code.
- Colors: To be determined.

3.2 Major Interior Systems

Interior surfaces and finishes will be selected for appropriateness to the individual spaces. Consideration will be given to the need for washdown, corrosion resistance, slip resistance, light reflectance, comfort, and maintenance. Major components have been investigated as follows:

- Floors: Concrete floor will receive a clear sealer or clear hardener where required for wear protection. Containment areas will receive a corrosion resistant coating as coordinated with Jacob's corrosion specialist.
- Walls: Interior block walls, concrete, and gypsum board substrates will be semi-gloss latex painted, as required, for light reflectiveness and wash-down. Corrosion resistant coating to be applied per Jacob's corrosion specialist.
- Ceilings: To be determined.
- Doors and Frames: Steel hollow metal with galvanized coating, factory primer, and field paint. Other doors and frames may include wood or fiberglass applications.
- Acoustical Treatment: The cogeneration facility may need surface-mounted metal panels with acoustical insulation or other acoustical measures to mitigate sound levels generated.
- Safety Equipment: Fire extinguishers will be located near egress doors. Other safety items may be incorporated into the project such as first-aid cabinets, emergency safety shower/eyewash provisions, safety equipment for specific chemicals, spill clean-up, and life buoys as the design progresses.
- Signage: Selected rooms will be provided with door nameplates; safety, informational and hazardous material signs will be provided, as required by code and safety standards.
- Colors: To be determined.

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Subject	Corrosion
Project Name	City of Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project
Jacobs Project Number	D3621900
To	Rob Chapler/City of Gresham
From	Patterson Tuttle
Reviewed by	Craig VanHorn
Date	March 7, 2023

1. Introduction

This technical memorandum (TM) summarizes materials selection and corrosion control recommendations for the Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project.

The materials selection and corrosion control recommendations presented in this memorandum are based on current Jacobs design best practices and experience with similar projects.

2. Corrosion Control During Construction

Electrical and instrumentation and control (I&C) equipment will be susceptible to damage during storage. Ideally, these items should be stored in air-conditioned buildings at the site.

The contractor must protect mechanical, structural, process, and architectural components from damage during handling. Whenever possible, painted surfaces must be cleaned and painted (at least with a prime coat) at the fabrication shop. This is especially important for metal piping where surface preparation by abrasive blasting is not practical once the piping is installed.

Fabricated stainless steel items will need to be shipped and handled such that no iron is embedded into the stainless steel surface. Fabrication of carbon steel items should be performed in work areas separate from stainless steel equipment to avoid contamination of the stainless steel by iron filings, dust, or deposits. Stainless steel that is contaminated by embedded iron will need to be cleaned and re-passivated.

Fiberglass-reinforced plastic (FRP) and thermoplastic materials will require special handling and field storage. Specific storage and handling information for these items should be obtained from the manufacturer.

3. Structural

3.1 Concrete

Sand and water used in concrete mixes for reinforced concrete structures must be free of chlorides. Type MS or HS cement may be acceptable depending on levels of sulfates in the soils and performance of

existing installations. American Concrete Institute (ACI) standards and practices should be followed for placement of concrete and thickness of cover over the reinforcing steel.

Due to the low pH of the anticipated high strength waste deliveries, which include fats, oils, greases (FOG) and food waste, special linings should be considered for the concrete surfaces in the new and existing digesters. Typical approaches for protecting concrete in these environments include the use of thermoplastic liners cast into the concrete or chemical-resistant coatings applied to cured concrete. Any coatings present in the existing digesters require evaluation, as the operating temperatures are being increased from about 98 degrees F (°F) to about 135°F and are likely no longer suitable for use. The higher temperature operation of thermophilic digesters presents concerns related to the use of traditional amine-cured epoxies, with multiple recent failures noted. The use of phenolic novolac epoxies or embedded thermoplastic liners may possibly be suitable for use. However, this requires further investigation and successful case histories from manufacturers for the specific products proposed for use.

3.2 Structural Steel

Structural steel will require high quality protective coatings. Surface preparation, priming, and finish coating should be done under controlled conditions at the fabrication facility prior to delivery to the site.

For structural steel within digesters and steel digester covers, the increase in existing digester operating temperature, from about 98°F to about 135°F, presents additional concerns. The higher temperature operation of thermophilic digesters presents concerns related to the use of traditional amine-cured epoxies, with multiple recent failures noted. The use of phenolic novolac epoxies may possibly be suitable for use. However, this requires further investigation and successful case histories from manufacturers for the specific products proposed for use.

3.3 Fasteners

- Submerged service: Type 316 (UNS S31600) stainless steel.
- Splash areas or wet areas (all fasteners): Type 316 stainless steel.
- Indoor wet and outdoor: Type 304 (UNS S30400) or Type 316 stainless steel.
- Indoor dry: Hot-dip galvanized steel.
- Anchor clips and bolts for FRP, galvanized, or aluminum grating and stairs: Type 316 stainless steel.
- Concrete anchors in immersion service: Epoxy adhesive anchors with Type 316 stainless steel fasteners.
- Concrete anchors in indoor and outdoor exposures: Type 304 or Type 316 stainless steel wedge anchors.

4. Fabricated Metalwork

4.1 Stainless Steel

Type 304 stainless is adequate for many areas requiring stainless steel. Type 304L (UNS S30403) or Type 316L (UNS S31603) stainless steel is required for fabricated stainless steel that requires welding. The use of low-carbon grades of stainless steel is required to avoid sensitization at the heat-affected zones adjacent to the welds. Stainless steel components should be cleaned and passivated after fabrication, and again after installation, if necessary, to remove all surface contaminants and produce a good appearance, following the methods described in American Society of Testing and Materials (ASTM) A380 and A967. All heat tint associated with welding will need to be removed.

4.2 Handrails, Grating, Stair Treads, and Platforms

Anodized aluminum, Type 304 stainless steel, or FRP are acceptable materials for handrails.

Aluminum or FRP are acceptable materials for grating and stair treads. Galvanized grating will not be used. Fasteners and hold-down clips should be stainless steel.

Platforms should be bare or coated galvanized steel, depending on the area and exposure. Aluminum and stainless steel can also be considered.

5. Mechanical

5.1 Equipment

A variety of materials are expected for equipment, depending on interior and exterior exposures. These include coated iron or steel, and stainless steel. Generally, the wetted components of equipment and components in contact with digester gas should be fabricated from Type 316 stainless steel. Type 304 or Type 304L stainless steel will be acceptable for most other applications. However, Type 316 or Type 316L stainless steel should be considered for submerged items of equipment and where deposits may settle on the surface from the process stream.

5.2 Piping and Supports

Ductile iron and carbon steel pipe are acceptable for most applications. Exterior surfaces will need to be protected by a high performance protective coating system. Interior surfaces will require cement mortar lining or epoxy coatings, suitable for the exposure condition. Glass lining should be considered for ductile iron in FOG service.

Preliminary approaches may be refined if soil corrosivity data are made available. Without soil corrosivity, it is currently recommended that for underground service, ductile iron pipe be double polyethylene encased in accordance with American Water Works Association (AWWA) C105. Carbon steel pipe should be polyethylene tape wrapped. Buried metallic fitting and joints with bolts, rods, and other angular shapes should be wax taped. Buried copper and stainless steel require further soil evaluation or performance of existing similar materials before being recommended for use.

Stainless steel pipe (Type 304), polyvinyl chloride (PVC), chlorinated polyvinyl chloride (CPVC), and high-density polyethylene (HDPE) pipe are acceptable for most indoor and outdoor exposures.

Pipe hangers and supports should be fabricated from Type 304 stainless steel.

5.3 Valves, Pumps, and Miscellaneous Appurtenances

Jacobs standard valve and pump materials should be acceptable. If special conditions or chemical exposure conditions are encountered, contact a member of the Corrosion Control Group for guidance. Provide protective coatings for all metallic items of equipment as recommended herein.

5.4 Electrical Components in Corrosive Areas

Electrical conduits in process areas should be PVC-coated rigid steel or a similar corrosion-resistant material. Similarly, electrical cable trays and conduit supports in these areas should be fabricated from Type 304 stainless steel.

6. Protective Coatings

Table 1 provides a list of proposed coating systems for surfaces requiring protection. The coating systems provide an appropriate level of protection for each anticipated exposure condition and have been proven in many WWTP applications.

Table 1. Preliminary Recommended Protective Coatings

Jacobs System No.	Environment/Material	Coating System^{a, b}
2	Submerged or partially submerged steel and ductile iron.	White metal blast. Three coats of polyamidoamine or phenalkamine-cured epoxy.
4	Steel and ductile iron in moderate to aggressive atmospheres (outdoors, indoor wet process areas or those with wash downs, and splash zones).	Near-white metal blast. One coat of epoxy primer, one coat of high-build epoxy intermediate coat, and one coat of polyurethane enamel finish.
5	Steel and ductile iron in mildly aggressive atmospheres (dry process areas).	Near-white metal blast. One coat epoxy primer, one coat polyurethane enamel finish.
7	Concrete encased steel and ductile iron (e.g., wall pipes, pipe sleeves).	Commercial blast. Two coats of epoxy.
25	Exposed FRP, PVC. ^c	Abrade surface. Two coats of acrylic latex paint.
27	Aluminum and dissimilar metal isolation.	Solvent clean. Prime in accordance with manufacturer's recommendations. Epoxy paint.
109	Masonry.	Clean. Apply block filler and two coats of acrylic latex.
110	Concrete sealer.	Clean. Apply two coats of siloxane sealer.
115	Gypsum board.	Clean. Apply one coat of latex primer sealer and two coats of acrylic latex.
117	Concrete masonry.	Clean. Apply block filler and two coats of water-based epoxy.

^aThe coatings listed above should be used by designers as a guide only and not as a coating specification since important information is not included (for example, coating dry film thickness).

^bAdditional coating systems may be identified during final design.

^cCoating for FRP and PVC structures is not required for indoor exposure conditions. FRP structures should be ordered in appropriate colors. FRP with integral UV-resistant gel coat does not require coating for outdoor exposure conditions.

FRP = fiberglass reinforced plastic; PVC = polyvinyl chloride.

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Subject	Electrical
Project Name	City of Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project
Jacobs Project Number	D3621900
To	Rob Chapler/ City of Gresham
From	Maricela Valenzuela
Reviewed by	Ryan Harbert
Date	March 7, 2023

1. Introduction

This technical memorandum (TM) describes the electrical design criteria for the Gresham Wastewater Treatment Plant (WWTP) Anaerobic Digestion and Cogeneration Expansion Project.

2. Applicable Codes, Standards, and Regulations

The design will be based on the following codes and standards.:

2.1 Codes

- National Electrical Code (NEC) (NFPA 70-2020)
- Life Safety Code (NFPA101)
- International Fire Code (IFC)
- National Electrical Safety Code (IEEE C2-2020)

2.2 Standards

- American National Standards Association (ANSI)
- National Electrical Manufacturers Association (NEMA)
- Institute of Electrical and Electronic Engineering (IEEE)
- Instrument Society of America (ISA)
- Insulated Cable Engineers Association (ICEA)
- Occupational Safety and Health Administration (OSHA)
- American Society for Testing Materials (ASTM)
- Underwriters Laboratory (UL)
- Illumination Engineering Society (IES)

- National Fire Protection Association (NFPA)
- Standard for Fire Protection in Wastewater Treatment and Collection Facilities (NFPA 820)

3. Evaluation

3.1 Existing Electrical System and Deficiencies

The WWTP currently has one 12.47 kilovolt (kV) utility incoming service from Portland General Electric (PGE). In addition, the WWTP includes 360 kilowatts (kW) of solar power generation and two ~400 kW cogeneration units.

The WWTP service, located southeast of the Blower Building Upper Plant, consists of a service switch and a PGE metering pad. The service switch then feeds MH-2 where power is distributed to MH-4 and 2,500 kilovolt-ampere (kVA) transformer that feeds SWBD-378 (Upper Blower Building). MH-4, which is located north of Upper Headworks Building, feeds a 600 kVA transformer that feeds SWBD-1189 (Upper Headworks Building) and a 1,600 kVA transformer that feeds Power Distribution Center (Lower Blower Building).

The 360 kW solar power generation is located to the east of the Blower Building Upper Plant. The two 398 kW cogeneration generators are located inside the Digester Control Building, which is west of the Administration Building.

The WWTP has two 200 kW standby generators. Standby generator GEN-1192 is located inside of Upper Headworks Building, which is southeast of the Administration Building. The standby generator GEN-8473 is located east of Digester 2.

4. Design Criteria

4.1 Electrical Distribution

Electrical distribution criteria are as follows:

- Utility service and primary distribution voltage: 12.47 kV.
- Equipment utilization voltage: 480Y/277, 3 phase, 4 wire and 480 volt (V), 3 phase, 3 wire.
- Lighting and receptacle voltage: 120 V, 1 phase.
- Control voltages: 120 volts alternating current (VAC) discrete, 24 VAC analog.
- Surge protection: Surge protection will be provided at all new 480 V distribution equipment and 208Y/120 V panelboards.
- Electrical distribution will follow the established pattern of single, radial feeders to major loads centers. Main-tie-main configuration and redundant feeder/transformer arrangements are generally not used.

4.2 Electrical Materials

Electrical materials design criteria are as follows:

- Conduit:
 - Wet, dry, or classified process areas: rigid galvanized steel (RGS) or intermediate metal conduit
 - Corrosive areas: polyvinyl chloride (PVC) coated RGS
 - Buried or imbedded in concrete: Schedule 40 PVC

- Boxes and enclosures:
 - Wet locations, outside, or corrosive: stainless steel NEMA 4X
 - Dry locations: gasketed NEMA 1, or 12
 - Classified areas: NEMA 7 where required

4.3 Voltage Drop

Steady state voltage drop calculations will be performed for all heavily loaded or long branch circuits and feeders. Calculations for motor circuits will be done on the basis of an 80 percent power factor and loading consistent with the maximum expected peak load (will not include standby motors). Total voltage drop will not exceed the following values from the transformer secondary to the point of utilization including feeder, branch circuit, and transformation:

- Lighting 3 percent
- Motors 4 percent
- Receptacles 4 percent
- Electric heaters 4 percent

4.4 Metering

Multifunction digital meters will be provided for all major new load centers such as motor control centers (MCCs), switchboards, and switchgear.

4.5 Branch Circuits

Connected load and NEC requirements will be used for sizing branch circuit breakers and conductors.

A minimum wire size of No. 12 American wire gauge (AWG) copper will be used for lighting and receptacle branch circuits. No. 10 AWG will be used when voltage drop requires a larger conductor on lighting circuits, and when receptacle circuits are longer than 75 feet.

In general, lighting branch circuit loads will be limited to 1,500 watts.

Lighting and receptacle branch circuits will not be combined.

The number of convenience receptacles on any branch circuit will be limited to five duplexes in process areas.

4.6 Raceway Systems

Separate duct banks and manhole networks will be used for the following systems:

- 480 V power wiring and 120 V control wiring
- Communications systems, including low voltage signal

Special consideration will be given to separation of raceways involving low-level process control signal wiring and power system wiring to minimize the possibility of interference.

General guidelines for raceway sizing, selection, and installation are given below:

- The following minimum sizes will be used:
 - ¾-inch minimum diameter for conduit installed exposed on walls and ceilings
 - ¾-inch minimum diameter for conduit concealed in frame construction and finished ceilings

- 1-inch minimum diameter for conduit embedded in masonry, encased in concrete, and underground
- Raceways will generally be exposed in process areas.
- Raceways will be concealed in walls and ceilings in control rooms, offices, and areas that have finished interiors.
- PVC-coated rigid galvanized steel conduit will be used for the transition from underground direct burial and under slab PVC conduit and concrete encased (in floor slab) PVC and rigid galvanized steel conduit to exposed rigid galvanized steel conduit. The transition section will extend from 1 foot below grade or top of floor slab or the last foot of conduit in the floor slab, to 6 inches out of the floor slab, concrete encasement, or above grade.
- The number of conduit bends will be limited to an equivalent of 270 degrees on long runs without pull boxes.
- PVC-coated rigid galvanized steel conduit and fittings that are resistant to direct sunlight and include an interior urethane coating will be used in exposed corrosive interior and exterior areas.
- PVC-coated rigid galvanized steel conduit will be used for underground direct burial low-voltage status/control (less than 100 V) and analog signal circuits.
- PVC Schedule 40 conduit and fittings will be used for underground direct burial, under slab, and concrete-encased 120 V circuits.
- PVC Schedule 40 conduit and fittings will be used for underground concrete-encased 480 V power circuits.
- Rigid galvanized steel conduit and fittings will be used when exposed or concealed in interior non-corrosive process and non-process areas, and in non-corrosive areas outdoors.
- Flexible, nonmetallic, liquid-tight conduit 4-inch or smaller in size will be used for connections to motors, transformers, etc., as required. Fittings will be PVC-coated in wet or corrosive areas.
- Underground conduit routes will be identified with nonmetallic warning tape above underground direct burial conduits.
- Spare raceways will be tagged with a nonferrous metal tag attached to the raceway with a nylon strap. Raceway tags with approved tag number provided by the contractor will identify the raceway origin and destination and will be located at each terminus, near the midpoint, and at minimum intervals of every 50 feet on exposed raceways (in ceiling spaces and surface-mounted).

4.7 Wire and Cable

Stranded copper conductors will be used for all except lighting and receptacle wiring. Solid conductors No. 10 AWG and smaller will be used for lighting and receptacle wiring.

Minimum conductor size of No. 12 AWG will be used for power and lighting branch circuits. Type THHN/THWN-2 insulation will be used for No. 10 AWG and smaller conductors (conduit will be sized for Type THW conductors). Type XHHW-2 insulation will be used for No. 8 AWG and larger conductors (conduit will be sized for THW conductors). 60-degree Celsius conductor ampacity rating will be used for sizing conductors No. 1 AWG and smaller. 75-degree Celsius ratings will be used for sizing conductors larger than No. 1 AWG.

Minimum conductor size of No. 14 AWG will be used for individual 120 V control circuits.

Minimum conductor size of No. 12 AWG will be used for 120 V control circuits routed in a common conduit with the power conductors to the motor circuit controls. Combining individual motor power and

control conductors in a common conduit will be done up to a maximum power conductor size of No. 2 AWG.

Power and control conductors will be color-coded. Conductors No. 8 AWG and smaller will have colored insulation. Conductors No. 6 AWG and larger will be color-coded with tape at each end and at accessible intermediate points.

Conductors and control cables will be tagged with a permanent sleeve or nylon marker plate attached with a nylon strap. Conductor tags with the approved tag number will be provided by the contractor and will be located at each termination and in accessible locations.

Under normal conditions, the maximum wire size will be limited to 500 kcmil. Parallel conductors will be used for circuits requiring greater capacity.

120 V control circuits will be combined in control cable containing multiple No. 14 WG stranded copper conductors with type THHN insulation and a common PVC outer jacket.

600 V multi-circuit control cable will be used where grouping control circuits is practical, and the number of individual wires exceeds six conductors. When selecting control cable size, 25 percent spare (plus or minus 10 percent) conductors will be used.

Multi-conductor control cable color coding will be ICEA S-61 402 Appendix K, Method 1, Table K-2.

Low voltage status/control (less than 100 V) and analog signal circuits will be routed in 600 V single twisted shielded pair instrumentation control cables. The cable will consist of No. 16 AWG stranded copper conductors with combination PVC/nylon insulation, drain wire, shield, and PVC outer jacket. Signal circuits will be combined in multi-twisted shielded pair instrumentation control cable with common overall shield. The cables will consist of No. 18 AWG stranded copper conductors, with a combination PVC/nylon insulation, pair and common drain wires, pair and common shields, and PVC outer jacket. Instrumentation control cables will be per ICEA S-82-552. Low voltage status/control and analog signal circuits will not be routed in the same control cable or conduit with 120 V control or power circuits. Low voltage status/control and analog signal circuits will be routed in the same conduit, but not in the same control cable.

Adequate separation of power and control wiring will be provided to avoid signal interference. Long parallel runs will be avoided, and analog wiring will be installed in steel conduit.

4.8 Convenience Receptacles

General service duplex receptacles will not be spaced more than 50 feet apart in process areas. Receptacles will be surface mounted on walls or columns.

Waterproof receptacles will be installed in damp areas or areas subject to washdown.

Outlet-mounted ground-fault circuit-interrupters (GFCIs) will be provided where required by the NEC. Panelboard or feed through type devices will not be used.

4.9 Panelboards

Branch circuit or feeders on the drawings will identify that panelboard and device protecting the individual circuit or feeder.

Each panelboard will be equipped with a minimum of 20 percent spare breakers with spaces, bus work, and terminations to complete the standard size panelboard.

Panelboard schedules indicating circuit identification, protective device trip rating, number of poles, load in volt-amps by phase, rating of main lugs or main circuit breaker, neutral bus size, ground bus size, and integrate short circuit rating of the panelboard will be prepared.

4.10 Motor Control

Motor control design criteria are as follows:

- New MCCs will be provided for all motor starters for new facilities.
- All motor starters and adjustable frequency drives (AFDs) will have hardwired analog and discrete inputs and outputs. Motor controllers will not be networked for control.
- Most starter cubicles will have the following:
 - 120 VAC control power transformer
 - Hand/Off/Auto selector switch
 - Green running light-emitting diode (LED) indicating pilot light
 - Red Motor Overload LED indicating pilot light
 - Red Motor Overtemp LED indicating pilot light
 - Amber ready LED indicating pilot light
 - White control power LED indicating pilot light
 - Amber blown fuse indication (BFI) LED indicating pilot light
- 24-hour ventilation starter cubicles will have the following:
 - 120 VAC control power transformer
 - Hand/Off/Auto selector switch
 - Green running LED indicating pilot light
 - Red Motor Overload LED indicating pilot light
 - Amber ready LED indicating pilot light
 - White control power LED indicating pilot light
 - Amber BFI LED indicating pilot light
- Unless additional disconnects are required by code, process motor disconnects will be located at the MCC in the electrical room, and not adjacent to the equipment. Lockout tagout safety practices can occur at the MCC.

4.11 Harmonic Mitigation

Variable frequency drives (VFDs) will create harmonics and waveform distortions in the WWTP electrical system. These harmonics can cause additional heating and possible disruption to more sensitive electronics. Utilities require facilities to meet IEEE 519- Recommended Practice and Requirements for Harmonic Control in Electrical Power Systems. Jacobs will include at minimum a 3-percent-line reactor for new AFDs to mitigate the harmonics created by the AFDs for the new loads.

4.12 Alternating Current Induction Motors

Enclosures for both horizontal and vertical motors 25 horsepower and smaller will be totally enclosed, fan cooled (TEFC) severe duty for indoor and outdoor locations. In wet and/or corrosive locations, chemical industry severe-duty (CISD-TEFC) motors will be used. Motors larger than 25 horsepower will be open drop-proof, unless TEFC, or CISD-TEFC is required for specific conditions (evaluated on a case-by-case basis considering cost and required physical protection). Submerged motors will be totally submersible, air-or oil-sealed. Bearings will be rated 100,000-hour Anti-Friction Bearings Manufacturers' Association (AFBMA) B-10 life.

Alternating current (AC) induction motors will be the premium efficiency type with the following:

- Motors will have a 1.15 service factor. Variable speed motors will have a 1.0 service factor.
- NEMA design letter to fit the application (usually NEMA design B), and locked rotor kVA Code G or lower.
- Motors will be cast iron.
- Bearings for horizontal and vertical motors will be grease-lubricated, with grease addition and relief fittings.
- Motor windings will be copper wire. Aluminum windings are not acceptable.
- TEFC motors will be equipment with weep holes and drain plugs to withdraw condensed moisture.
- Motors operated by VFDs will be specified inverter duty rated and may also be provided with isolating bearings and/or shaft grounding rings depending on size and cost.

4.13 Grounding

The new equipment will be connected to existing or new grounding system. Equipment grounding will be provided for new equipment. New facilities will be provided with new NEC grounding systems. A separate ground conductor sized in accordance with NEC requirements will be installed in raceways for power feeders and branch circuit raceways for motor control, lighting, and receptacle loads. Shields of shielded instrumentation cables will be grounded to the ground bus at the power supply for the analog or low voltage discrete signal circuit. Shielded instrumentation cables will not be grounded at more than one point.

Lightning protection systems will not be provided.

4.14 Lighting

All new facility luminaires (and replacement of existing luminaires in existing facilities) will have LED type fixtures. LED fixtures will be energy efficient, industrial duty, with instant on/off controls, with exception in the electrical rooms. LED lights will have diffusers that distribute light evenly and are more comfortable to the eye than undiffused LEDs. Most spaces will have linear type fixture that provides even light distribution similar to linear fluorescent luminaires. All wet locations will have waterproof, gasketed fixtures.

Explosion-Proof Luminaires: Any room or space listed as a hazardous atmosphere will have explosion-proof type luminaires UL listed for installation in the hazardous area classifications, as required by Article 500 of the NEC.

Exterior Luminaires: Each new exterior door will have a full cut-off light fixture that minimizes light pollution at night, but aides in ingress and egress from the door at night. Pole-mounted area lights will match existing concrete poles with LED luminaires. Site lighting pole lights will be provided along new or revised roadways. Exterior lighting will be controlled by photocell.

Emergency Luminaires: Emergency illumination will be provided in appropriate spaces, as required by code to provide life safety, property, and equipment protection.

Adequate lighting levels will be provided to maintain safe building egress and critical process plant functions. Emergency lighting will be located near MCCs and any equipment locations that need to be monitored on a continuing basis. Exit signs with a battery pack will be provided at each egress door.

In large process areas, emergency standby lighting units with a battery pack and two lamps and lighted exit signs with a battery pack will be provided. The battery pack will power the lights for at least 90 minutes.

In non-process and finished areas, lights and exit signs with emergency battery packs will be provided.

4.15 Fire Alarm System

A new fire alarm system will be provided in the new Digester Control Building. The fire alarm system will include the following:

- Pull stations
- Heat detectors
- Smoke detectors
- Notification devices (horns and strobes)
- Connections to other systems as required, such as monitoring fire sprinkler systems.
- Combustible gas detection
- Declassification ventilation monitoring
- Horn/strobe notification appliances
- Red/green "GO-NO GO" lights to alert personnel of ventilation or gas detection issues

The fire alarm system will be networked to the existing fire alarm system and existing monitoring services. The fire alarm system will also be monitored by the supervisory control and data acquisition system so that the plant operators will know if there is an active fire alarm system alarm.

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Subject	Geotechnical
Project Name	City of Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project
Jacobs Project Number	D3621900
To	Rob Chapler/City of Gresham
From	Lopamudra Bhaumik
Reviewed by	Todd Cotten, P.E., G.E.
Date	March 7, 2023

1. Existing Geotechnical Information

Geotechnical information related to subsurface conditions and geotechnical properties at the Gresham Wastewater Treatment Plant (WWTP) site is available from the previous geotechnical explorations, as summarized below. Logs of the subsurface conditions encountered in each of the borings is provided in Attachment 1.

- Shannon and Wilson (SW) advanced three borings (B-1-SW79 through B-3-SW79) in 1979 at the north of the project site, and two borings (B-1-SW82 and B-2-SW82) in 1982 at the southeast of the project site. The boring logs are present in a report titled: *Geotechnical Investigation Phase I Expansion Gresham Wastewater Treatment Plant* (Fujitani Hilts and Associates, 1997).
- Geotechnical Consultants advanced six mud-rotary and two auger borings (DH-1-GC86 through DH-8-GC86) at various locations within the project site in 1986. The boring logs are present in a report titled: *Geotechnical Investigation Phase I Expansion Gresham Wastewater Treatment Plant* (Fujitani Hilts and Associates, 1997).
- CH2M HILL advanced four mud-rotary borings (B-1-CH92 through B-4-CH92) around the existing digested sludge storage building at the northwest of the project site in 1992. The results are presented in a report titled: *Geotechnical Exploration for Proposed Municipal Digested Sludge Storage Facility* (CH2M HILL, 1992).
- Fujitani Hilts and Associates advanced ten mud-rotary borings (B-1-FH97 through B-10-FH97) at various locations within the project site in 1997. The results are presented in a report titled: *Geotechnical Investigation Phase I Expansion Gresham Wastewater Treatment Plant* (Fujitani Hilts and Associates, 1997).
- Hart Crowser advanced one mud-rotary boring (HC-1-17), two hand-auger borings (HA-1-HC17 and HA-2-HC17), and four drive probe soundings (DP-1-HC17 through DP-4-HC17) at the northeast corner of the project site in 2017. The results are presented in a report titled: *Gresham Waste Water Treatment Plant - Geotechnical Slope Evaluation* (Hart Crowser, 2017).

A summary of the previously completed geotechnical borings is provided in Table 1, and approximate locations of these borings are also shown in Figure 1.

Table 1. Summary of Previously Completed Borings

Firm	Exploration	Ground Surface Elevation (ft)	Exploration Depth (ft, bgs)	Estimated Depth to Troutdale Formation (ft, bgs)	Standpipe Piezometer	Water Level (ft, bgs)
Shannon and Wilson, 1979 and 1982	B-1-SW79	53	28.8	1.0	-	-
	B-2-SW79	61	29.2	1.7	-	-
	B-3-SW79	55	28.8	8.2	Yes	> 28.8 (2/7/79)
	B-1-SW82	75	15.4	4.5	-	-
	B-2-SW83	82	15.7	4.5	-	-
Geotechnical Consultants, 1986	DH-1-GC86	68.5	35.5	8.0	-	-
	DH-2-GC86	57	27	7.0	Yes	25 (3/20/86)
	DH-3-GC86	48.5	20.5	8.0	-	-
	DH-4-GC86	59	25.5	10.0	-	-
	DH-5-GC86	65	12	10.0	-	-
	DH-6-GC86	65	16	10.0	Yes	> 16 (3/20/86)
	DH-7-GC86	56.5	25.5	13.0	-	-
	DH-8-GC86	59	10	5.0	-	-
CH2MHILL, 1992	B-1-CH92	59.3	30.4	25.0	-	-
	B-2-CH92	61.8	15.3	10.8	-	-
	B-3-CH92	54.2	20.3	13.5	-	-
	B-4-CH92	64.5	20.3	17.0	-	-
Fujitani Hilts and Associates, 1997	B-1-FH97	64.3	26.5	NE	-	-
	B-2-FH97	64.4	30.3	28.0	-	-
	B-3-FH97	58.8	25.3	0.0	Yes	23.3 (7/2/97, 7/15/97)
	B-4-FH97	66.5	10.4	0.0	-	-
	B-5-FH97	71.3	15.5	4.5	-	-
	B-6-FH97	72.2	10.4	0.0	-	-
	B-7-FH97	68.8	25.3	3.0	-	-
	B-8-FH97	73.8	25.3	4.5	-	-
	B-9-FH97	72.6	25.3	3.4	-	-
	B-10-FH97	79.3	25.4	2.5	Yes	20.8 (7/2/97) 24.2 (7/15/97)
Hart Crowser 2017	HC-1-17	63	28	15.0	-	-
	HA-1-HC17	55	9.5	9.5	-	-
	HA-2-HC17	55	8.6	8.6	-	-

bgs = below ground surface; ft = feet; NE = Not Encountered.

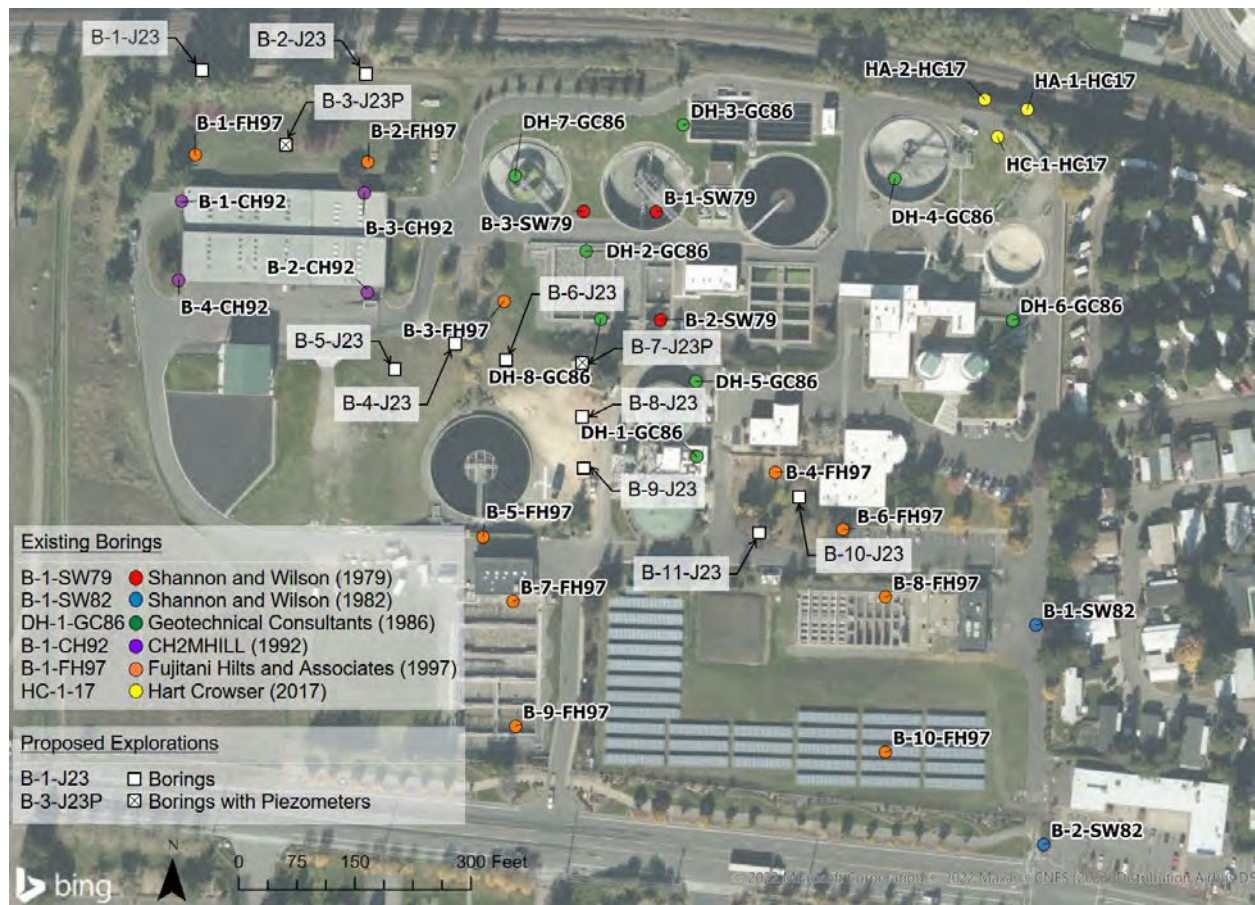


Figure 1. Existing and Proposed Boring Locations

2. General Geology

The Gresham WWTP is located within the Willamette Valley segment of the Puget-Willamette Lowland geological province. This geological province is a structural and erosional lowland area bordered by the uplifted volcanic and marine rocks of the Coast Range to the west and volcanic rocks of the Cascade Range to the east. The Willamette Lowland extends from Eugene, Oregon, north to the Lewis River in southern Washington. In the northern two-thirds of the lowland, the marine sedimentary rocks and Cascade Range volcanic rocks are overlain by up to 1,000 feet of lava of the Columbia River Basalt Group (CRBG). Folding and faulting during and after incursion of the CRBG formed four major depositional basins: the Portland Basin, Tualatin Basin, central Willamette Valley Basin, and southern Willamette Valley Basin. These basins, separated in most places by uplands capped by CRBG, have locally accumulated more than 1,600 feet of fluvial sediment derived from the Cascade and Coast ranges or transported into the region by the Columbia River (Gannett and Caldwell, 1998).

The project site is located near the center of the Portland Basin, south of the Columbia River. The mapped geologic units in the project area consist of the following (Trimble, 1963; Wells et al., 2020):

- **Alluvium (Qa)** consists of Holocene sand, silt, and gravel deposited along flood plains of the Columbia River and generally less than 50 feet thick. This unit may contain areas of artificial fill.
- **Coarse-Grained Missoula Flood Deposits (Qfc)** consists of bouldery, cobbly, sandy gravel bars deposited by the Missoula floods as they spilled into the Portland Basin from the Columbia River.

Locally, the thickness of this unit may be more than 100 feet. Wells et al. (2020) reports that coarse-grained Missoula Flood Deposits are present in the project area.

- **Troutdale Formation (Tt)** consists of pebble-cobble conglomerate and pebbly sandstone, with minor amounts of siltstone and claystone. The conglomerate mainly consists of Columbia River basalt. Trimble (1963) reports that this formation may be up to 1,000 feet thick. Wells et al. (2020) reports that the sandstone member of the Pliocene Troutdale Formation is present in the project area. This member consists of coarse-grained basaltic sandstone and granule conglomerate, often containing pebbles, cobbles, and well sorted sandy beds.

3. Subsurface Conditions

The general subsurface soil profile is described here is based on the geotechnical data from the existing geotechnical explorations, and a review of the regional geologic conditions.

- Fill consisting of loose to medium dense silty sand (SM) and soft to medium stiff silt, silt with sand, and sandy silt (ML) with occasional gravel and construction debris consisting of concrete blocks were encountered in certain borings like B-1-FH97, B-2-FH-97, and B-1-CH92 through B-4-CH92. This layer is underlain by the alluvium or by weathered Troutdale Formation.
- Alluvium consisting of brown loose to medium dense silty sand (SM) and firm to stiff non-plastic silt (ML) was encountered in certain borings for instance borings B-1-CH92 through B-4-CH92. This unit is present overlying the Troutdale Formation.
- Troutdale Formation consisting of gray to yellowish-brown and reddish-brown, lightly to strongly cemented poorly graded sand (SP), poorly graded sand with silt (SP-SM), well graded sand (SW), and poorly graded gravel (GP) was encountered in all the historical borings except B-1-FH97. This unit underlies either the fill or the alluvium layer. Refusal standard penetration test (SPT) N-values were measured in this formation indicating very dense soils. Table 1 lists the top of the Troutdale Formation that was encountered in the geotechnical explorations.

4. Groundwater Conditions

Historical groundwater data were measured in standpipe piezometers installed in the borings including one Shannon and Wilson boring B-3-SW79 in 1979, two Geotechnical Consultants borings DH-2-GC86 and DH-6-GC86 in 1986, and two Fujitani Hilts & Associates, Inc., borings B-3-FH97 and B-10-FH97 in 1997. Groundwater was not encountered in the two hand-auger borings HA-1-HC17 and HA-2-HC17 advanced by Hart Crowser in 2017. The available historical groundwater data are presented in Table 1.

5. Seismic Design Considerations

5.1 Seismic Design Criteria

The seismic design of the proposed structures shall be performed in general accordance with the following standards:

- American Society of Civil Engineers/Structural Engineering Institute (ASCE/SEI) Minimum Design Loads and Associated Criteria for Buildings and Other Structures 2022 Edition (ASCE 7-22).
- International Building Code 2018 (IBC 2018).

5.2 Seismic Design Parameters

The soil site classification for the project area shall be determined per ASCE 7-22, Chapter 20 (ASCE 2022) using shear wave velocity averaged over the upper 100 feet of the soil column. Currently, shear

wave velocity data are not available at the project site. As discussed in Section 8, the proposed geotechnical investigation plan includes measurement of shear wave velocity using geophysical methods.

The 2,475-year Maximum Considered Earthquake, MCE_G determined from the U.S. Geological Survey 2018 uniform hazard response spectrum (UHS) data shall be used for the geotechnical seismic hazard analysis including liquefaction, cyclic softening, and lateral spreading.

5.3 Potential for Liquefaction, Cyclic Softening, and Lateral Spreading

Liquefaction refers to the loss of shear strength that saturated granular soil deposits (gravels, sands, and non- to low-plasticity silts) can experience during undrained cyclic loading, such as earthquake loading. Liquefaction occurs when pore pressures in the soil increase to the point where the effective stress in the soil approaches zero. When the effective stress in the soil approaches zero, the shear strength of the soil decreases and permanent deformations in the soil can accumulate to large values (cyclic shear strain greater than 3 percent). Liquefaction can result in soil settlement and lateral spreading (Boulanger and Idriss, 2014).

Cyclic softening refers to the loss of shear strength that saturated fine-grained soil deposits (medium to high plasticity clays and silts) can experience during undrained cyclic loading, such as earthquake loading. It involves the generation of pore pressures and reduction of effective stress in the soil, typically to a lesser extent than in granular soil deposits. Cyclic softening is governed by the stress history, percent fines, age of deposit, loading rate, and undrained shear strength of the soil deposit among other factors. Cyclic softening can result in post-seismic soil settlement.

Lateral spreading is a special case of seismic slope instability that involves the lateral movement of ground on and within a zone of liquefied soil. Lateral spreading can occur when liquefaction occurs in a relatively widespread and continuous layer, and it can occur on gentle slopes or adjacent to an open face slope, such as a ravine or riverbank. The lateral spreading case history databases include slope gradients as flat as 0.5 percent (National Academies of Sciences, Engineering, and Medicine, 2016).

The soil layers encountered in the existing exploration program suggest that the fill or alluvium layer present beneath the proposed facilities may be susceptible to liquefaction in the silty sands or cyclic softening in the silts if they are saturated, that is, if these soils are below the permanent groundwater table or a perched groundwater table. For instance, the surficial silty sand (SM) fill layer encountered in boring B-1-FH97 with SPT N-value of 5, and the poorly graded sand with silt (SP-SM) layer in boring B-2-FH97 from 5 to 28 feet bgs with SPT N-value less than 10 may be susceptible to liquefaction if saturated. The surficial silt (ML) fill layer in boring B-2-FH97 with SPT N-value of 5 may undergo cyclic softening if saturated.

The historical groundwater data indicate that in the vicinity of the High Strength Waste Receiving Expansion, Thermophilic Digester, Digester Control Building, and Gas Storage facilities the groundwater is at about 23 feet bgs in the very dense Troutdale Formation. Thus, the groundwater is below the potentially liquefiable zone, or zone susceptible to cyclic softening.

Groundwater data in the immediate vicinity of the Cogeneration Facility, Biosolids Storage Facility, and the Waste Gas Burner are not available. However, the general historical groundwater data in the seven explorations at the project site indicate that the groundwater is present below the surficial soil layers that have potential for liquefaction.

Based on the above discussion and the historical groundwater data, the risk of lateral spreading due to liquefaction in the project area is considered to be low. These groundwater data are preliminary and should be supplemented with data from proposed monitoring piezometers discussed in Section 8.

5.4 Seismic Settlement Mitigation

Excavation and replacement would be a low-cost alternative for seismic settlement mitigation if shallow groundwater in the fill or alluvium layer is encountered in the proposed geotechnical explorations. It might not be possible to remove the fill and alluvium entirely where new structures are located near existing facilities. In these cases, the approach might be to use rigid inclusions or piles driven down to the Troutdale Formation. This would address seismic settlement; however, this would not mitigate for the potential of lateral spread if present.

6. Foundation Design

Foundations for the proposed facilities may be constructed using conventional shallow foundation systems such as mat foundations, spread footings, or column footings provided the structures and associated equipment within the facilities can tolerate estimated total and differential settlement. Based on the historical data at the site, it is anticipated that the top of the Troutdale formations will vary from close to the ground surface to about 10 feet bgs for the Thermophilic Digester, Digester Control Building, High Strength Waste Receiving Expansion, Gas Storage, and Cogeneration facilities.

The northwest part of the site, where the proposed Biosolids Storage Facility is currently planned, contains mounded fill material. It is unlikely that this was engineered fill that was compacted during placement. It is anticipated that this fill would be excavated and removed for construction of the new facility. Portions of the excavated fill could potentially be reused as granular fill beneath selected facilities. Unused excavated fill would have to be disposed at a designed area on the site or taken offsite.

Mat foundations and other footings should be located below the frost depth, at least 24 inches below final grade. Mat foundation should be founded on a minimum of 8 inches of compacted granular fill placed above the prepared subgrade. Overexcavation of 12 inches minimum and backfilling with compacted granular fill may be required to construct a level subgrade. At locations where shallow Troutdale Formation is encountered, overexcavation may be required as needed to reach the Troutdale Formation layer, removing all loose, fine- and coarse-grained fill and alluvial material.

Ground improvements may include but not be limited to stone columns or grouting. No further discussion is provided in this report for ground improvements. The design geotechnical engineer should be engaged if this direction is chosen.

7. General Geotechnical Considerations

7.1 Excavation

Open cut excavation will be utilized for the majority of the construction area, with excavation to varying subgrade elevations based upon footing elevations and constructability. Excavations can be made using standard excavation equipment. Temporary excavation slopes must comply with state, local, and federal codes, ordinances, and regulations. Recommendations regarding temporary excavation sloping, shoring, sheeting, bracing, or methods to minimize effects on existing utilities are highly dependent on the contractor's selected excavation method and construction procedures. For this reason, Jacobs recommends that the construction contractor be made responsible for the design of temporary slopes and trench support systems. This will permit the contractor to select a system particularly suited to planned construction procedures.

A temporary or permanent retaining wall system may be required for support of the excavation and construction of the proposed facilities and to protect existing structures for facilities near slope transitions or for facilities in the vicinity of existing structures; for instance, the new Digester 3 located near the existing Digester 2. Limitations, design loads, and performance requirements of the retaining wall system shall be developed as part of the final design and be included in the contract documents. Movement

monitoring points shall be established prior to excavation and these points shall be protected during construction to allow for continual wall and ground movement monitoring.

7.2 Shoring

Large, open cut excavations will be required for the construction of the proposed structures at the site. Excavations deeper than 5 feet but less than 20 feet in depth should have protective systems in place to protect workers from cave-ins. Protective systems include sloping, benching, shielding, or shoring. The contractor is responsible for maintaining stable cut slopes and providing the necessary shoring in accordance with Occupational Safety and Health Administration or regional code requirements.

Any shoring system used to support the excavation should be designed and sealed by a licensed engineer in the State of Oregon working on behalf of the construction contractor. In addition, trenches deeper than 20 feet should be supported with a positive ground support system designed and sealed by a licensed engineer in Oregon.

7.3 Dewatering

Groundwater is not anticipated to be present during excavation of the proposed new facilities based on historical groundwater data. These groundwater data are considered preliminary.

If dewatering is required, dewatering gravity systems, such as sumps, well points or deep wells, set below the excavation bottom to dewater open excavations may be necessary. The selection of the appropriate dewatering system depends on the depth of excavation and the season of the year. The contractor is responsible for selecting the means and methods to accomplish dewatering at the site. Construction water will be disposed in an approved retention basin or disposal area.

Surface water should be controlled and diverted away from excavations to prevent soil raveling and piping of fine material.

8. Proposed Geotechnical Investigation Plan

The proposed borings have been located based on the site plan and changes to the locations will be made if there is a change in the layout. Field reconnaissance will be completed by Jacobs to review proposed locations of geotechnical explorations, identify site limitations including overhead utilities, and identify access requirements. Locations of the borings may be revised so that they can be advanced from areas that can be accessed without excessive site clearing and improve site safety during the exploration program.

The proposed geotechnical exploration program consists of:

- Geotechnical investigation that includes eleven borings at the new facility locations. A summary of the proposed borings is presented in Table 2 and shown in Figure 1.
- Documentation of SPT N-values to estimate the liquefaction and cyclic softening potential of the soils, and to correlate with material density, strength, and stiffness for the stability evaluations.
- Laboratory testing of SPT samples for physical analysis of selected samples collected from the geotechnical borings.
- Measurement of shear wave velocity using geophysical methods.
- Installation and collection of groundwater data from two standpipe piezometers including vibrating wire piezometers at borings B-1-J23P and B-7-J23P.

Table 2. Proposed Geotechnical Borings Summary

Exploration	Exploration Depth (ft, bgs)	Standpipe and Vibrating Wire Piezometer
B-1-J23	20 ^a	-
B-2-J23	20 ^a	-
B-3-J23P	60 ^a	Yes
B-4-J23	70 ^b	-
B-5-J23	70 ^b	-
B-6-J23	40 ^b	-
B-7-J23P	80 ^b	Yes
B-8-J23	60 ^b	-
B-9-J23	40 ^b	-
B-10-J23	70 ^b	-
B-11-J23	70 ^b	-

^a or 15 feet into the Troutdale Formation.

^b or 25 feet into the Troutdale Formation.

Drilling will be completed in the presence of a Jacobs engineer who will direct the drilling operations, collect samples, and provide continuous observation and logging of each of the boreholes.

Depending on the conditions encountered, Jacobs may recommend adjustments to the additional field work during the field investigation. If these adjustments would result in additional cost, Jacobs will notify the City of Gresham prior to conducting this additional work to discuss the benefits of collecting the additional information.

As previously mentioned, changes in the nature, design, or location of the planned facilities will require an update of this technical memorandum and the proposed geotechnical exploration plan.

9. References

Boulanger, R.W. and I.M. Idriss. 2014. *CPT and SPT Based Liquefaction Triggering Procedures*. Report No. UCD/CGM-14/01, Center for Geotechnical Modeling, Department of Civil and Environmental Engineering, University of California Davis. April.

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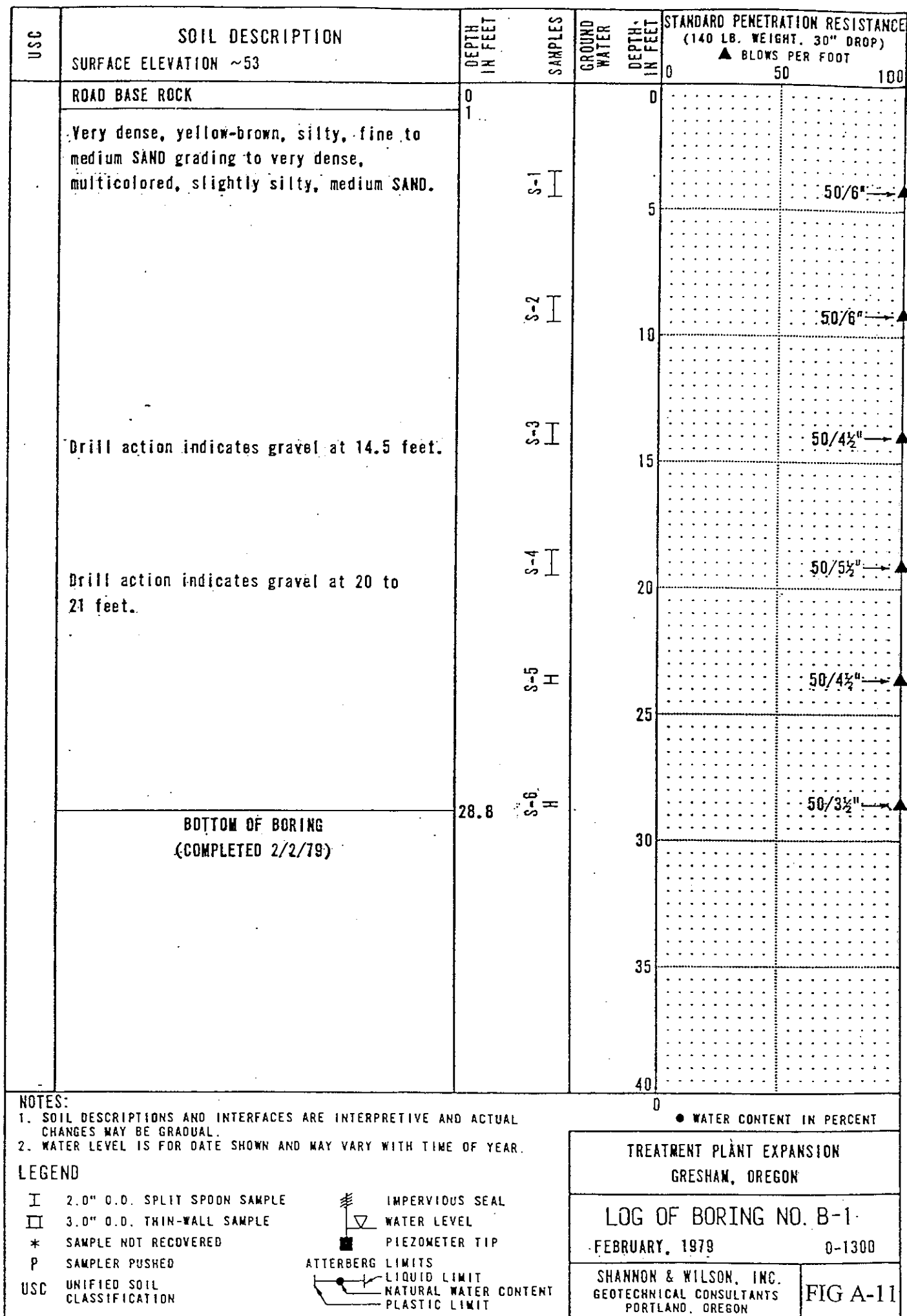
Hart Crowser. 2017. *Gresham Waste Water Treatment Plant - Geotechnical Slope Evaluation*. May 31.

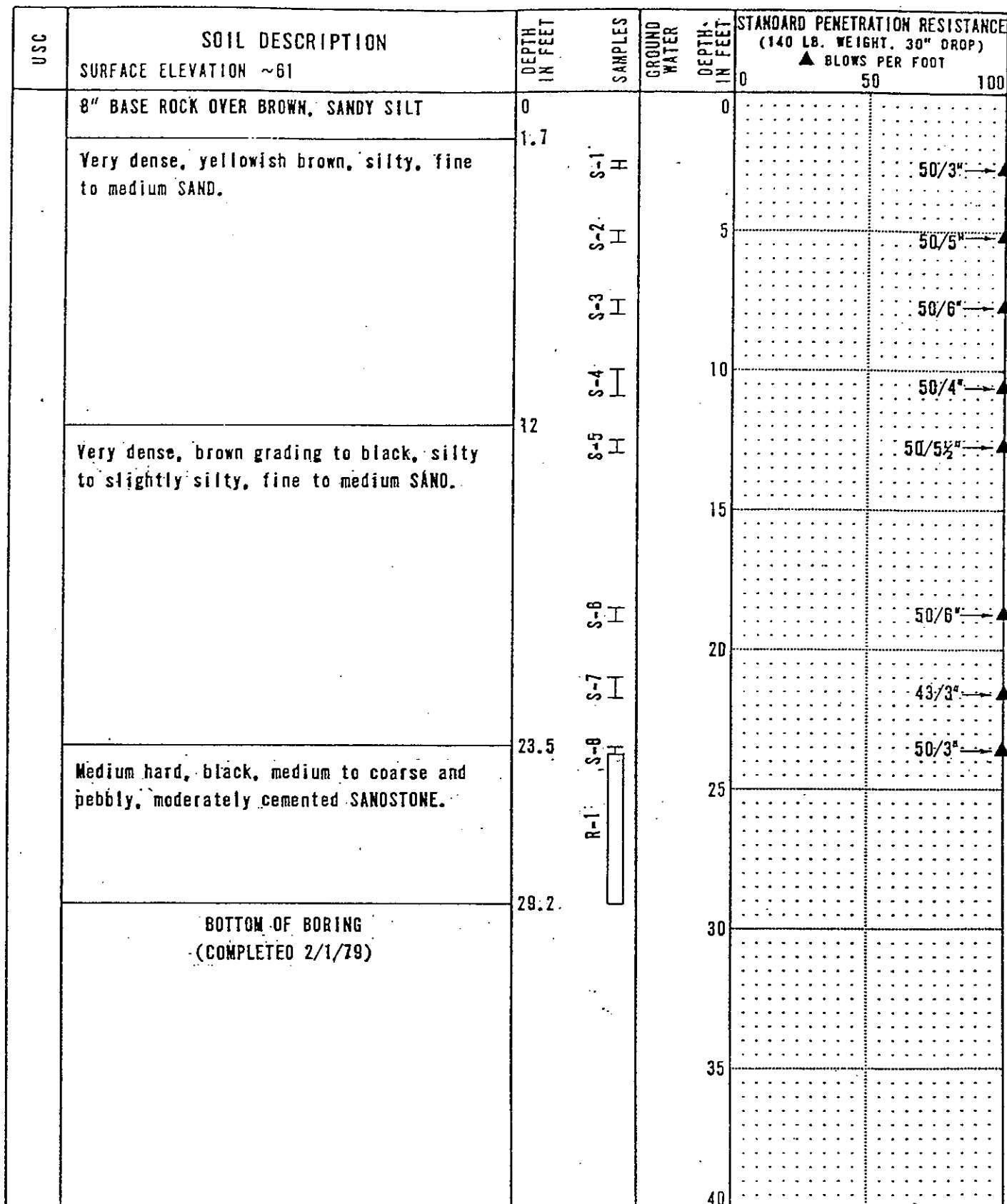
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Attachment 1
Previous Exploration Boring Logs





NOTES:

1. SOIL DESCRIPTIONS AND INTERFACES ARE INTERPRETIVE AND ACTUAL CHANGES MAY BE GRADUAL.
2. WATER LEVEL IS FOR DATE SHOWN AND MAY VARY WITH TIME OF YEAR.

LEGEND

⊞ 2.0" O.D. SPLIT SPOON SAMPLE

□ NX CORE

* SAMPLE NOT RECOVERED

P SAMPLER PUSHED

USC UNIFIED SOIL CLASSIFICATION

⊞ IMPERVIOUS SEAL

▽ WATER LEVEL

■ PIEZOMETER TIP

ATTERBERG LIMITS

— LIQUID LIMIT

— NATURAL WATER CONTENT

— PLASTIC LIMIT

● WATER CONTENT IN PERCENT

TREATMENT PLANT EXPANSION
GRESHAM, OREGON

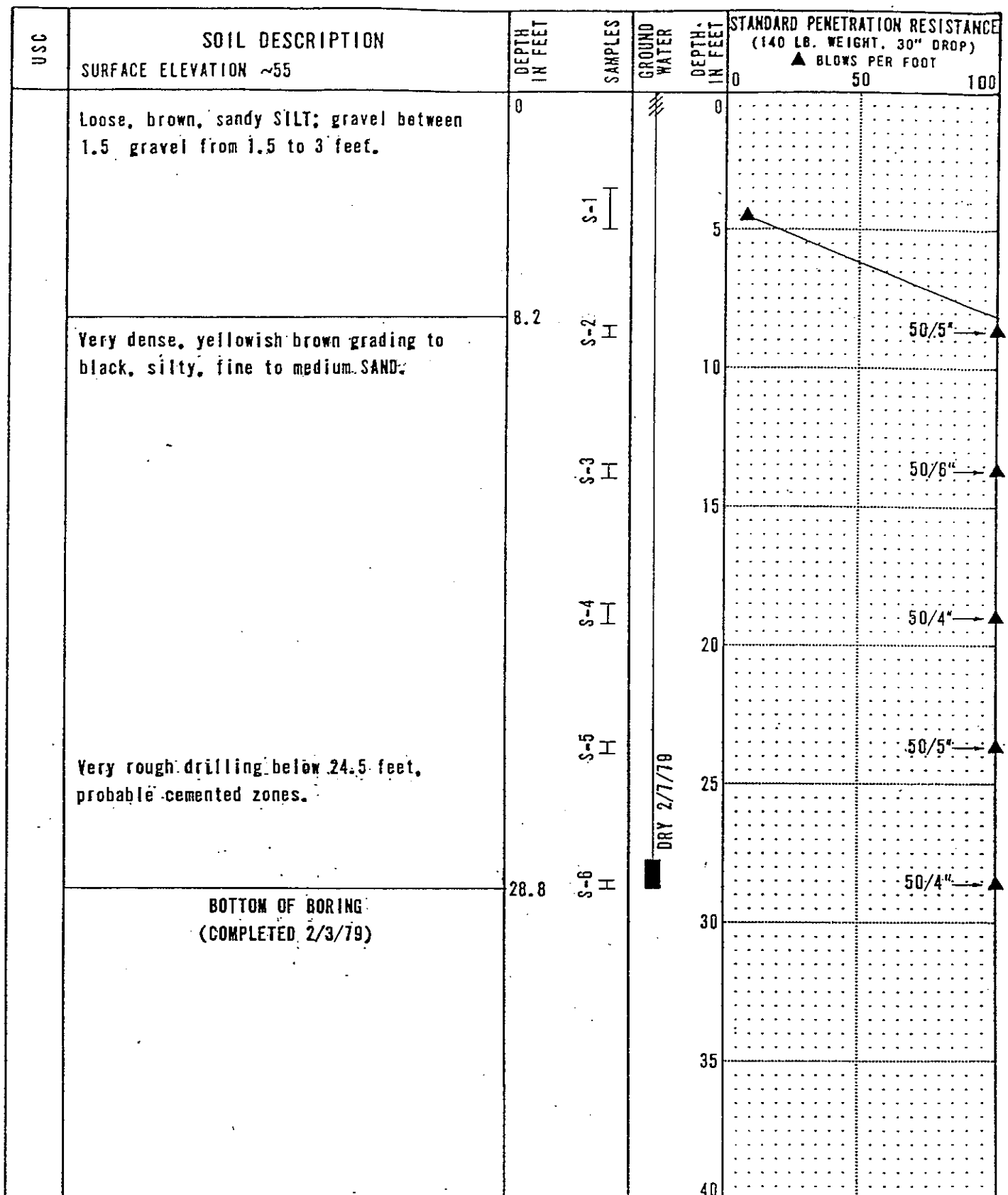
LOG OF BORING NO. B-2

FEBRUARY, 1979

0-1300

SHANNON & WILSON, INC.
GEOTECHNICAL CONSULTANTS
PORTLAND, OREGON

FIG A-12



NOTES:

1. SOIL DESCRIPTIONS AND INTERFACES ARE INTERPRETIVE AND ACTUAL CHANGES MAY BE GRADUAL.
2. WATER LEVEL IS FOR DATE SHOWN AND MAY VARY WITH TIME OF YEAR.

LEGEND

I 2.0" O.D. SPLIT SPOON SAMPLE

II 3.0" O.D. THIN-WALL SAMPLE

* SAMPLE NOT RECOVERED

P SAMPLER PUSHED

USC UNIFIED SOIL CLASSIFICATION

IMPervious SEAL

WATER LEVEL

PIEZOMETER TIP

ATTERBERG LIMITS

LIQUID LIMIT

NATURAL WATER CONTENT

PLASTIC LIMIT

• WATER CONTENT IN PERCENT

TREATMENT PLANT EXPANSION
GRESHAM, OREGON

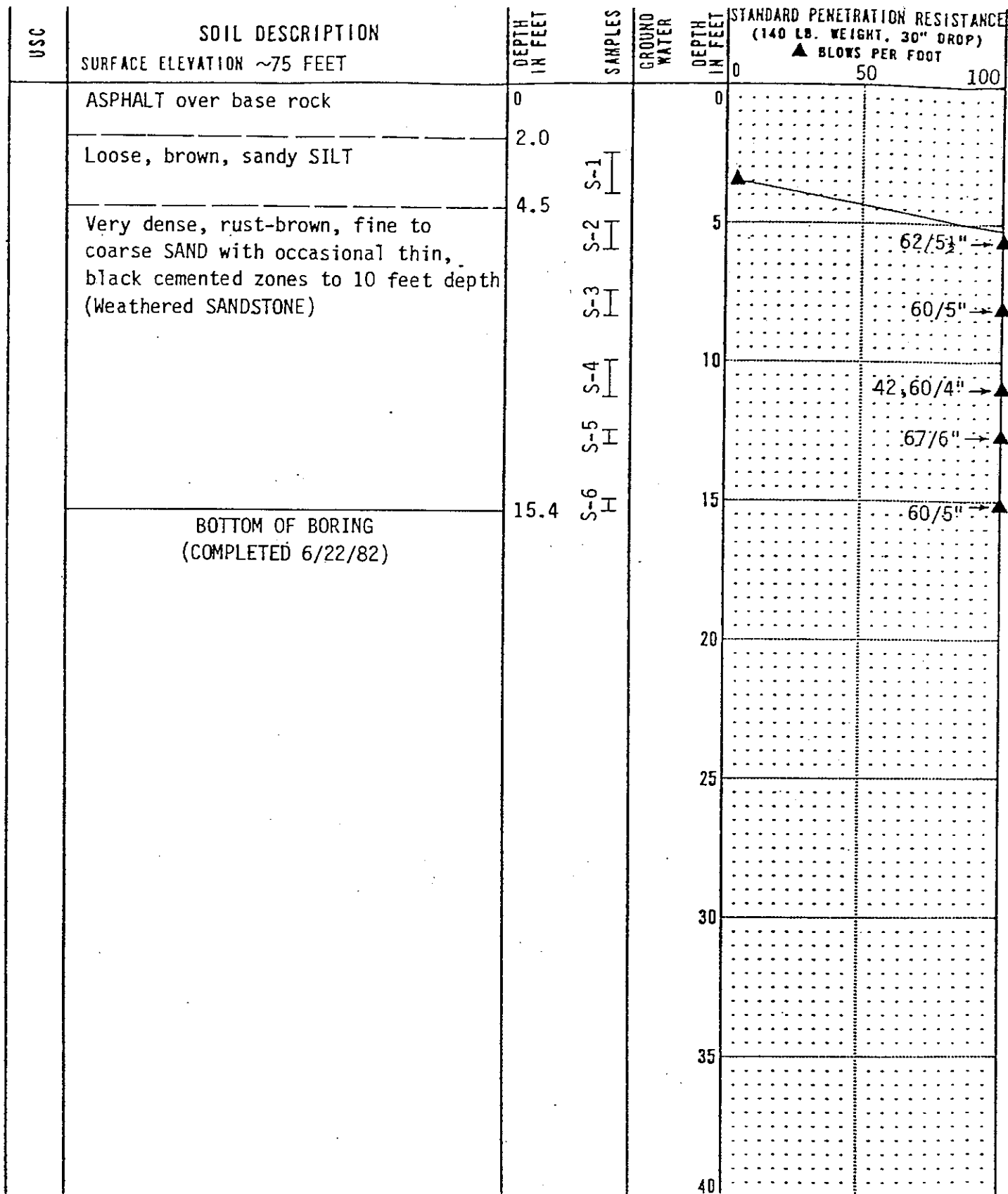
LOG OF BORING NO. B-3

FEBRUARY, 1979

0-1300

SHANNON & WILSON, INC.
GEOTECHNICAL CONSULTANTS
PORTLAND, OREGON

FIG A-13



NOTES:

1. SOIL DESCRIPTIONS AND INTERFACES ARE INTERPRETIVE AND ACTUAL CHANGES MAY BE GRADUAL.
2. WATER LEVEL IS FOR DATE SHOWN AND MAY VARY WITH TIME OF YEAR.

LEGEND

- | | | | |
|-----|-----------------------------|--|-----------------------|
| I | 2.0" O.D. SPLIT SPDM SAMPLE | | IMPERVIOUS SEAL |
| □ | 3.0" O.D. THIN-WALL SAMPLE | | WATER LEVEL |
| * | SAMPLE NOT RECOVERED | | PIEZOMETER TIP |
| P | SAMPLER PUSHED | | ATTERBERG LIMITS |
| USC | UNIFIED SOIL CLASSIFICATION | | LIQUID LIMIT |
| | | | NATURAL WATER CONTENT |
| | | | PLASTIC LIMIT |

INTERCEPTOR SEWER PROJECT
GRESHAM, OREGON

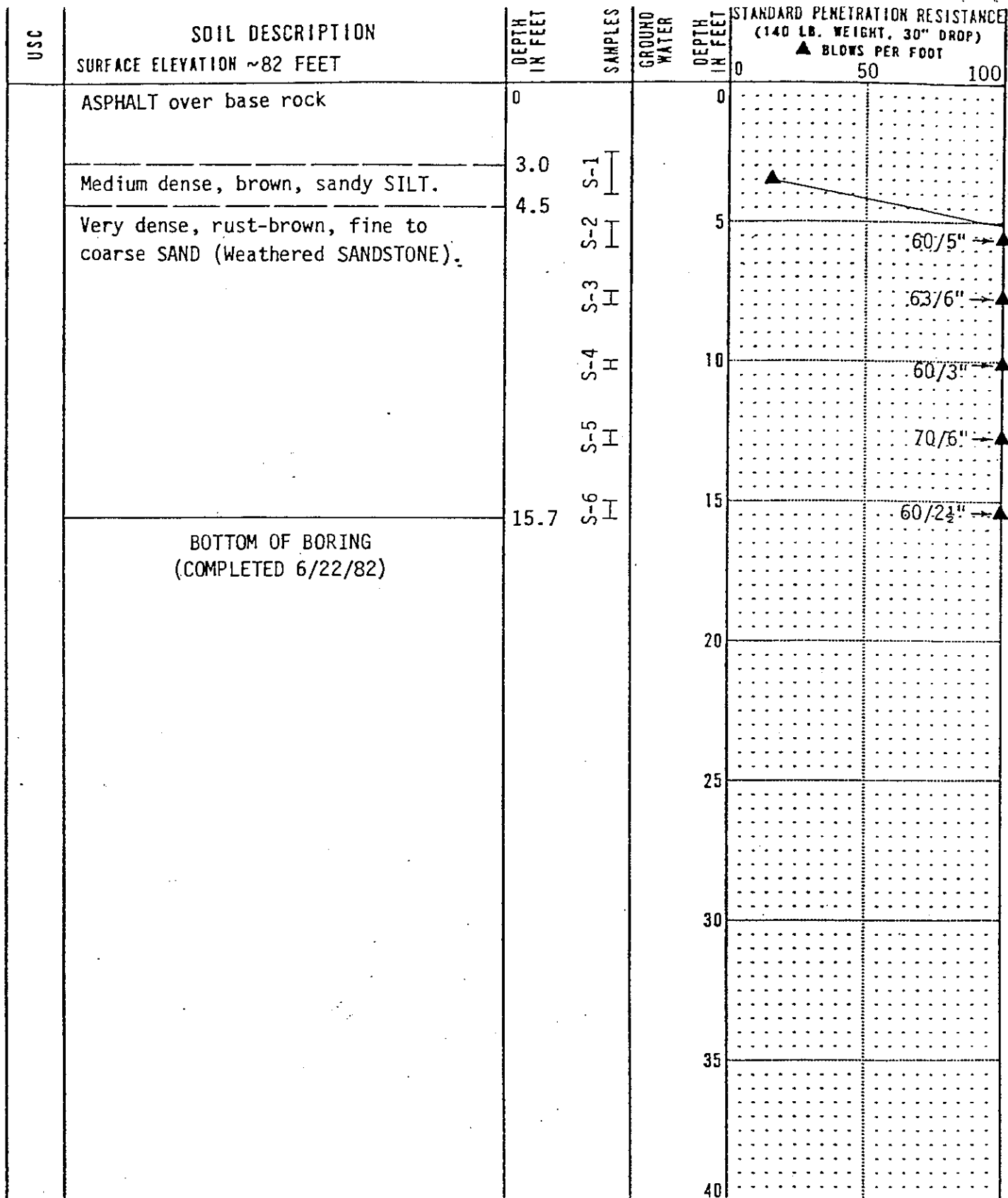
LOG OF BORING NO. B-1

JULY, 1982

0-1622-1

SHANNON & WILSON, INC.
GEOTECHNICAL CONSULTANTS
PORTLAND, OREGON

FIG A-9



NOTES:

1. SOIL DESCRIPTIONS AND INTERFACES ARE INTERPRETIVE AND ACTUAL CHANGES MAY BE GRADUAL.
2. WATER LEVEL IS FOR DATE SHOWN AND MAY VARY WITH TIME OF YEAR.

LEGEND

- | | | | |
|-----|------------------------------|--|-----------------------|
| I | 2.0" O.D. SPLIT SPOON SAMPLE | | IMPERVIOUS SEAL |
| II | 3.0" O.D. THIN-WALL SAMPLE | | WATER LEVEL |
| * | SAMPLE NOT RECOVERED | | PIEZOMETER TIP |
| P | SAMPLER PUSHED | | ATTERBERG LIMITS |
| USC | UNIFIED SOIL CLASSIFICATION | | LIQUID LIMIT |
| | | | NATURAL WATER CONTENT |
| | | | PLASTIC LIMIT |

INTERCEPTOR SEWER PROJECT
GRESHAM, OREGON

LOG OF BORING NO. B-2

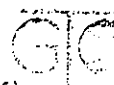
JULY, 1982

0-1622-1

SHANNON & WILSON, INC.
GEOTECHNICAL CONSULTANTS
PORTLAND, OREGON

FIG A-10

LOG OF DRILL HOLE



JOB NO.: SF85058
 PROJECT: Gresham WTP
 LOCATION: Gresham, OR
 DRILLING METHOD: Rotary Wash

LOGGED BY: MRC
 CHECKED BY: JFM

DRILL HOLE NO.: 1 (BV-5)
 DRILLING DATE: 2/11/86
 DATUM:
 REFERENCE EL.: 68½

ELEVATION (FEET)	DEPTH	DRILLING RATE (MINUTES/FEET) AND CASING	SAMPLE	SAMPLE NO.	BLOW COUNT (BLOWS PER FOOT)	GRAPHIC LOG	GEOTECHNICAL DESCRIPTION AND CLASSIFICATION	DRY DENSITY (PCF)	MOISTURE CONTENT (%)	ATTERBERG LIMITS		TORVANE (PSI)	ADDITIONAL TESTS
										LIQUID LIMIT (%)	PLASTIC LIMIT (%)		
63½		++++			12		"TOPSOIL" SANDY SILT (ML), brown, wet, trace clay w/ grass	95	24				DS
		++++			12		"LACUSTRINE DEPOSITS" SANDY SILT (ML), tan, moist, soft						
		++++					some clay present		26				GS
10		++++			50 3"		"TROUTDALE FORMATION" SANDSTONE, tan, dry, dense becoming dark olive green						
		++++					less dense at 12'						
53½		++++			50 5"		dense, weathered, gravelly (1/4"-1/2")						
20		++++			50 1"								
43½		++++					Attempted core run from 25' to 30' Recovered 4" sample from approximately 27' (small basaltic boulder).						
30		++++			50 4"								
33½		++++			50 3"								
		++++					Bottom of drill hole at a depth of 35½ feet. Drill hole backfilled						

LOG OF DRILL HOLE

JOB NO.: SF85058
 PROJECT: Gresham WTP
 LOCATION: Gresham, OR
 DRILLING METHOD: Rotary Wash

LOGGED BY: MRC
 CHECKED BY: JFM

DRILL HOLE NO.: 2 (BV-6)
 DRILLING DATE: 2/12/86
 DATUM
 REFERENCE EL.: 57 feet

ELEVATION (FEET)	DEPTH	DRILLING RATE (MINUTES/FEET) AND CASING	SAMPLE NO.	BLOW COUNT (BLOWS PER FOOT)	GRAPHIC LOG	GEOTECHNICAL DESCRIPTION AND CLASSIFICATION	DRY DENSITY (PCF)	MOISTURE CONTENT (%)	ATTERBERG LIMITS		TORVANE (PSI)	ADDITIONAL TESTS
									LIQUID LIMIT (%)	PLASTIC LIMIT (%)		
52		++++		7		"TOPSOIL" SANDY SILT (ML), tan, very moist, soft w/ grass		24				GS
				12		"LACUSTRINE DEPOSITS" SILTY SAND (SM), tan, moist, loose, fine grained. becoming more sandy		24				GS
10		++++		85 11"		"LACUSTRINE DEPOSITS" SAND (SP/SM) brown, moist, loose to medium dense, fine to medium grained, minor silt content.		14				
42		++++		50 5"		"TROUTDALE FORMATION" SANDSTONE, dark grey, low moisture, weathered cobbles with sandy matrix. coarse gravels		16				
20		++++		50 3"		medium gravels, coarse sand		16				
32		++++		50 2"								
22		++++				Bottom of drill hole at a depth of 27 feet. Piezometer Installed (2" PVC with 2' of slotted tip) and drill hole backfilled with sand, capped with 2' of bentonite. Ground water observed @ 25' on 3/20/86.						

LOG OF DRILL HOLE

gpc

JOB NO.: SF85058
PROJECT: Gresham WTP
LOCATION: Gresham, OR
DRILLING METHOD: Rotary Wash

LOGGED BY: MRC
CHECKED BY: JFM

DRILL HOLE NO.: 3 (BV-3)
DRILLING DATE: 2/12/86
DATUM
REFERENCE EL.: 48½

ELEVATION (FEET)	DEPTH	DRILLING RATE (MINUTES/FEET) AND CASING	SAMPLE NO.	BLOW COUNT (BLOWS PER FOOT)	GRAPHIC LOG	GEOTECHNICAL DESCRIPTION AND CLASSIFICATION	DRY DENSITY (PCF)	MOISTURE CONTENT (%)	ATTERBERG LIMITS		TORVANI (PSI)	ADDITIONAL TESTS
									LIQUID LIMIT (%)	PLASTIC LIMIT (%)		
43½		+		17		"TOPSOIL" SANDY SILT (ML), brown, very soft with grass		25				
		+		14		"LACUSTRINE DEPOSITS" SANDY SILT (ML), tan, moist, medium firm, very fine grained sand, traces dark grey clay and fine gravel(½")	98	20				DS
10		+		88		"LACUSTRINE DEPOSITS" SILTY SAND(SM), tan, moist, loose to medium dense, fine grained						
33½		+		50		"TROUTDALE FORMATION" SANDSTONE, yellow-brown with black gravels (½"), moist medium grained sand, weathered, becoming dense and hard						
		+		50		some coarse gravel becoming dark grey		23				
20		+		50								
23½		+				Bottom of drill hole at a depth of 20½ feet. Drill hole backfilled.						

LOG OF DRILL HOLE

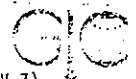
JOB NO.: SF85058
 PROJECT: Gresham WTP
 LOCATION: Gresham, OR
 DRILLING METHOD: Rotary Wash

LOGGED BY: MRC
 CHECKED BY: JFM

DRILL HOLE NO.: 4(BV-2)
 DRILLING DATE: 2/12/86
 DATUM:
 REFERENCE EL.: 59

ELEVATION (FEET)	DEPTH	DRILLING RATE (MINUTES/FEET) AND CASING	SAMPLE NO.	BLOW COUNT (BLOWS PER FOOT)	GRAPHIC LOG	GEOTECHNICAL DESCRIPTION AND CLASSIFICATION	DRY DENSITY (PCF)	MOISTURE CONTENT (%)	ATTERBERG LIMITS		TORGAN (PSI)	ADDITIONAL TESTS
									LIQUID LIMIT (%)	PLASTIC LIMIT (%)		
54		+		68		"TOPSOIL" SILT (ML), brown, wet, soft with grass	110	14				DS, C
		+		9		"LACUSTRINE DEPOSITS" SANDY SILT (ML), dark brown, moist, firm, minor gravel content (1/4"-3/4")		23				
10		+		96		"LACUSTRINE DEPOSITS" SAND (SP/SM), dark grey, moist, medium dense,		23				
		+		11"		"TROUTDALE FORMATION" SANDSTONE, dark grey, moist, very dense, sandy becoming gravelly (1/4"-1/2") with coarse sand		23				
44		+		50				24				
		+		4"				24				
20		+		50				22				
		+		5"				22				
34		+		50				20				
		+		5"				20				
						Bottom of drill hole at a depth of 25 1/2 feet. Drill hole backfilled.						

LOG OF DRILL HOLE



JOB NO.: SF85058
 PROJECT: Gresham WTP
 LOCATION: Gresham, OR
 DRILLING METHOD: 6" Auger

LOGGED BY: MRC
 CHECKED BY: JFM

DRILL HOLE NO.: 5 (8V-7)
 DRILLING DATE: 2/12/86
 DATUM:
 REFERENCE EL.: 65



ELEVATION (FEET)	DEPTH	DRILLING RATE (MINUTES/FEET) AND CASING	SAMPLE	SAMPLE NO.	BLOW COUNT (BLOWS PER FOOT)	GRAPHIC LOG	GEOTECHNICAL DESCRIPTION AND CLASSIFICATION	DRY DENSITY (PCF)	MOISTURE CONTENT (%)	ATTERBERG LIMITS		TORVANE (PSI)	ADDITIONAL TESTS
										LIQUID LIMIT (%)	PLASTIC LIMIT (%)		
60					16		"TOPSOIL" SANDY SILT (ML), brown, moist, soft, with grass	92	20				CP, EI, GS, DS, C
					2		"LACUSTRINE DEPOSITS" SANDY SILT (ML), brown, moist, soft, gravel layer from 1'-1.5', some clay content.		27				
							tan, very silty, soft		25				
10					62		"TROUTDALE FORMATION" SANDSTONE, brown, dry, dense, coarse sands, fine gravel becoming very dense		16				
					50				25				
-50							Bottom of drill hole at a depth of 12' (Auger Refusal). Drill hole backfilled.						

LOG OF DRILL HOLE

JOB NO.: SF85058
 PROJECT: Gresham WTP
 LOCATION: Gresham, OR
 DRILLING METHOD: Rotary Wash

LOGGED BY: MRC
 CHECKED BY: JFM

DRILL HOLE NO.: 6 (BV-1)
 DRILLING DATE: 2/27/86
 DATUM:
 REFERENCE EL.: 65

ELEVATION (FEET)	DEPTH	DRILLING RATE (MINUTES/FEET) AND CASING	SAMPLE	SAMPLE NO.	BLOW COUNT (BLOWS PER FOOT)	GRAPHIC LOG	GEOTECHNICAL DESCRIPTION AND CLASSIFICATION	DRY DENSITY (PCF)	MOISTURE CONTENT (%)	ATTERBERG LIMITS		TORVANI (PSI)	ADDITIONAL TESTS
										LIQUID LIMIT (%)	PLASTIC LIMIT (%)		
60		++++		17	5		"TOPSOIL" SANDY SILT (ML), brown, wet, soft with grass "LACUSTRINE DEPOSITS" SANDY SILT (ML), tan, very moist, soft to medium firm, very fine grained, traces brown clay.	98	21				DS
10		++++		75	11		"TROUTDALE FORMATION" SANDSTONE, grey-brown, dry, dense, sand matrix with some coarse gravels.	15					GS
50		++++		80	8								
20		++++					Bottom of drill hole at a depth of 16 feet. Piezometer installed (1" PVC with 2' of slotted tip) and drill hole backfilled with sand, capped with 2' of bentonite. "Trace" of water observed in bottom of piezometer on 3/20/86						

LOG OF DRILL HOLE

JOB NO.: SF85058
 PROJECT: Gresham WTP
 LOCATION: Gresham, OR
 DRILLING METHOD: Rotary Wash

LOGGED BY: MRC
 CHECKED BY: JFM

DRILL HOLE NO.: 7 (BV-4)
 DRILLING DATE: 2/27/86
 DATUM:
 REFERENCE EL.: 561

ELEVATION (FEET)	DEPTH	DRILLING RATE (MINUTS/FEET) AND CASING	SAMPLE NO.	BLOW COUNT (BLOWS PER FOOT)	GRAPHIC LOG	GEOTECHNICAL DESCRIPTION AND CLASSIFICATION	DRY DENSITY (PCF)	MOISTURE CONTENT (%)	ATTERBERG LIMITS		TORVANE (PSI)	ADDITIONAL TESTS
									LIQUID LIMIT (%)	PLASTIC LIMIT (%)		
51½		++++		50 5"		"TOPSOIL" SANDY SILT (ML), tan, wet, soft with grass						
				13		"LACUSTRINE DEPOSITS" SANDY SILT (ML), dark grey, moist, medium firm to very firm, cemented coarse gravels and cobbles to 3". tan/light brown, very moist, soft to medium firm, very fine grained.		23				
				41		"LACUSTRINE DEPOSITS" GRAVEL (GM), with silt, dark grey, dense		24				GS
41½		++++		80 11"		"TROUTOALE FORMATION" SANDSTONE, yellow-brown/black mottled, low to medium moisture, dense, very sandy, medium to coarse gravel		25				
				90 9"		coarse sand and gravel layers very dense		15				
31½		++++		50 5"				18				
30		++++				Bottom of drill hole at a depth of 25½ feet. Drill hole backfilled						

LOG OF DRILL HOLE

JOB NO.: SF85058
 PROJECT: Gresham WTP
 LOCATION: Gresham, OR
 DRILLING METHOD: 6" Auger

LOGGED BY: MRC
 CHECKED BY: JFM

DRILL HOLE NO.: 8 (BV-8)
 DRILLING DATE: 2/17/86
 DATUM:
 REFERENCE EL.: 59' (est.)

ELEVATION (FEET)	DEPTH	DRILLING RATE (MINUTES/FEET) AND CASING	SAMPLE	SAMPLE NO.	BLOW COUNT (BLOWS PER FOOT)	GRAPHIC LOG	GEOTECHNICAL DESCRIPTION AND CLASSIFICATION	DRY DENSITY (PCF)	MOISTURE CONTENT (%)	ATTERBERG LIMITS		TORVANE (PSI)	ADDITIONAL TESTS
										LIQUID LIMIT (%)	PLASTIC LIMIT (%)		
54	10	++++			55		"TOPSOIL" SANDY SILT (ML), tan, wet, soft with grass						
					50		SILTY GRAVEL (GM), light brown, moist, medium dense, 3/4" maximum rounded						
					50		"LACUSTRINE DEPOSITS"						
					50		SANDY GRAVEL (GP), yellow-brown, moist, dense, very angular						
					50		"TROUTDALE FORMATION"		10				
					50		SANDSTONE, yellow-brown, low moisture, dense, minor gravel						
					50		becoming very dense, dark grey coarse sands		10				
44	20	++++					Bottom of drill hole at a depth of 10 feet(auger refusal). Drill hole backfilled.						



PROJECT NUMBER

PDX31814.A2

BORING NUMBER

B-1

SHEET 1 OF 2

SOIL BORING LOG

PROJECT City of Gresham WWTP

LOCATION Gresham WWTP

ELEVATION 59.3

DRILLING CONTRACTOR D.A. Kenner Drilling of Oregon, Inc.; Sherwood, OR

DRILLING METHOD AND EQUIPMENT Mud Rotary - CME 55

WATER LEVELS Not Encountered

START 11/25/91 0820

FINISH 11/25/91 1040

LOGGER D.P. Lutz

DEPTH BELOW SURFACE (FT)	SAMPLE			STANDARD PENETRATION TEST RESULTS 6" - 6" - 6" (N)	SOIL DESCRIPTION SOIL NAME, USCS GROUP SYMBOL, COLOR, MOISTURE CONTENT, RELATIVE DENSITY OR CONSISTENCY, SOIL STRUCTURE, MINERALOGY	COMMENTS DEPTH OF CASING, DRILLING RATE DRILLING FLUID LOSS TESTS AND INSTRUMENTATION
	INTERVAL	TYPE AND NUMBER	RECOVERY INCHES			
5.0	2.5					
	4.0	SS-1	15	10-18-38 (56)	POORLY GRADED SAND with SILT, (SP-SM), light brown with yellow-orange mottling and black specks, moist, very dense.	
	5.0					
	6.5	SS-2	8	19-31-27 (58)	POORLY GRADED SAND with SILT, (SP-SM), yellow, light brown, red, moist, very dense.	
	7.5					
10.0	9.0	SS-3	12	6-5-6 (11)	SANDY SILT, (ML), brown and red, moist, stiff, trace gravel.	Driller notes softer drilling at 7 feet
	10.0					
	11.5	SS-4	5	3-5-3 (8)	SILT with SAND, (ML), brownish-yellow, brown, red, black gravel, moist, firm, non-plastic.	
	12.5					
	14.0	SS-5	7	3-3-3 (6)	SILT with SAND, (ML), brown, yellow, moist, firm, fine grained sand, non-plastic.	
15.0	15.0					
	16.5	SS-6	6	3-3-4 (7)	SILT, (ML), brown, yellow, some red, wet, firm.	
	17.5					
	19.0	SS-7	12	1-4-5 (9)	SILT, (ML), tan and orange, moist, stiff, non-plastic.	Apparently native ground surface
	20.0					
20.0	22.0	ST-8	16	PUSH	POORLY GRADED SAND, (SP), light brown, moist.	Top 10 inches soft Bottom 6 inches firm PP=2.0 TSF TV=.25 TSF
	23.5	SS-9	11	7-10-11 (21)	SILTY SAND, (SM), light brown, moist, medium dense, micaceous.	
	25.0					
	25.9	SS-10	10	31-60/4"	POORLY GRADED SAND, (SP), yellow-brown and some black, moist, very dense, apparently the Troutdale Formation, cemented.	
30.0						



PROJECT NUMBER
PDX31814.A2

BORING NUMBER
B-1

SHEET 2 OF 2

SOIL BORING LOG

PROJECT City of Gresham WWTP

LOCATION Gresham WWTP

ELEVATION 59.3

DRILLING CONTRACTOR D.A. Kenner Drilling of Oregon, Inc.; Sherwood, OR

DRILLING METHOD AND EQUIPMENT Mud Rotary - CME 55

WATER LEVELS Not Encountered

START 11/25/91 0820

FINISH 11/25/91 1040

LOGGER D.P. Lutz

DEPTH BELOW SURFACE (FT)	SAMPLE			STANDARD PENETRATION TEST RESULTS 6" -6" -6" (N)	SOIL DESCRIPTION	COMMENTS
	INTERVAL	TYPE AND NUMBER	RECOVERY INCHES		SOIL NAME, USCS GROUP SYMBOL, COLOR, MOISTURE CONTENT, RELATIVE DENSITY OR CONSISTENCY, SOIL STRUCTURE, MINERALOGY	DEPTH OF CASING, DRILLING RATE DRILLING FLUID LOSS TESTS AND INSTRUMENTATION
	30.0 30.4	SS-II	5	60/5"	POORLY GRADED SAND, (SP), similar to above. END OF BORING AT 30.4 FEET	
35.0						
40.0						
45.0						
50.0						
55.0						



PROJECT NUMBER PDX31814.A2	BORING NUMBER B-2
SHEET 1 OF 1	
SOIL BORING LOG	

PROJECT <u>City of Gresham WWTP</u>	LOCATION <u>Gresham WWTP</u>
ELEVATION <u>61.8</u>	DRILLING CONTRACTOR <u>D.A. Kenner Drilling of Oregon, Inc.; Sherwood, OR</u>
DRILLING METHOD AND EQUIPMENT <u>Mud Rotary - CME 55</u>	
WATER LEVELS <u>Not Encountered</u>	START <u>11/25/91 1100</u> FINISH <u>11/25/91 1205</u> LOGGER <u>D.P. Lutz</u>

DEPTH BELOW SURFACE (FT)	SAMPLE			STANDARD PENETRATION TEST RESULTS	SOIL DESCRIPTION	COMMENTS
	INTERVAL	TYPE AND NUMBER	RECOVERY INCHES			
				6" - 6" - 6" (N)		
5.0	2.5				SILT, (ML), light brown and some red pecks, moist, stiff, non-plactic, trace of gravel.	Apparently Troutdale Formation
	4.0	SS-1	3	3-3-3 (9)		
	5.0					
	6.5	SS-2	11	3-4-4 (8)	SILT, (ML), light brown with some red specks, moist, firm, non-plastic.	
	7.5				SILT, (ML), similar to above, except stiff.	
	9.0	SS-3	14	3-4-5 (9)		
10.0						
10.0	11.5	SS-4	18	2-6-35 (41)	Top 10 inches - SILT, (ML), light brown with red specks, moist, firm, non-plastic. Bottom 8 inches - SILTY SAND, (SM), light brown, red, and yellow, moist, very dense, slightly cemented.	
	12.5				POORLY GRADED SAND with SILT, (SP-SM), light brown, yellow, and red, moist, very dense, less cemented than sample above.	
	13.0	SS-5	4	50/6"		
	15.0					
15.0	15.3	SS-6	4	60/4"	POORLY GRADED SAND, (SP), dark brown, yellow-brown, greenish- brown, moist, very dense.	
					END OF BORING AT 15.3 FEET	
20.0						
25.0						



PROJECT NUMBER
PDX31814.A2

BORING NUMBER
B-3

SHEET 1 OF 1

SOIL BORING LOG

PROJECT City of Gresham WWTP

LOCATION Gresham WWTP

ELEVATION 54.2

DRILLING CONTRACTOR D.A. Kenner Drilling of Oregon, Inc.; Sherwood, OR

DRILLING METHOD AND EQUIPMENT Mud Rotary - CME 55

WATER LEVELS Not Encountered

START 11/25/91 1300

FINISH 11/25/91 1430

LOGGER D.P. Lutz

DEPTH BELOW SURFACE (FT)	SAMPLE			STANDARD PENETRATION TEST RESULTS 6" - 6" - 6" (N)	SOIL DESCRIPTION SOIL NAME, USCS GROUP SYMBOL, COLOR, MOISTURE CONTENT, RELATIVE DENSITY OR CONSISTENCY, SOIL STRUCTURE, MINERALOGY	COMMENTS DEPTH OF CASING, DRILLING RATE DRILLING FLUID LOSS TESTS AND INSTRUMENTATION
	INTERVAL	TYPE AND NUMBER	RECOVERY INCHES			
5.0	2.5					
	4.0	SS-1	12	8-6-5 (11)	<u>SILT with SAND</u> , (ML), light brown and dark brown, some gray, red specks, moist, stiff, non-plastic.	
	5.0					
	6.5	SS-2	8	2-3-2 (5)	<u>SILT with SAND</u> , (ML), dark brown, gray, moist, firm, non-plastic.	
	7.5					
10.0	9.0	SS-3	7	3-2-5 (7)	<u>SANDY SILT</u> , (ML), brown, moist, firm, non-plastic.	
					<u>SANDY SILT</u> , (ML), similar to above.	
	11.0	ST-4	20	PUSH		PP=2.25 TV=0.2
	12.5	SS-5	16	2-2-3 (5)	<u>SILT</u> , (ML), light brown, moist, firm, non-plastic, micaceous.	
15.0	15.0					Driller notes harder drilling at 13.5 feet
	15.8	SS-6	10	29-60/4"	<u>POORLY GRADED SAND with SILT</u> , (SP-SM), yellow-brown and brown, moist, very dense, slightly cemented.	Apparently Troutdale Formation
20.0	20.0					
	20.3	SS-7	3	60/4"	<u>POORLY GRADED SAND</u> , (SP), yellow-brown, moist, very dense, slightly cemented.	
					END OF BORING AT 20.3 FEET 1430 11/25/91	
25.0						



PROJECT NUMBER

PDX31814.A2

BORING NUMBER

B-4

SHEET 1 OF 1

SOIL BORING LOG

PROJECT City of Gresham WWTP

LOCATION Gresham WWTP

ELEVATION 64.5

DRILLING CONTRACTOR D.A. Kenner Drilling of Oregon, Inc.; Sherwood, OR

DRILLING METHOD AND EQUIPMENT Mud Rotary - CME 55

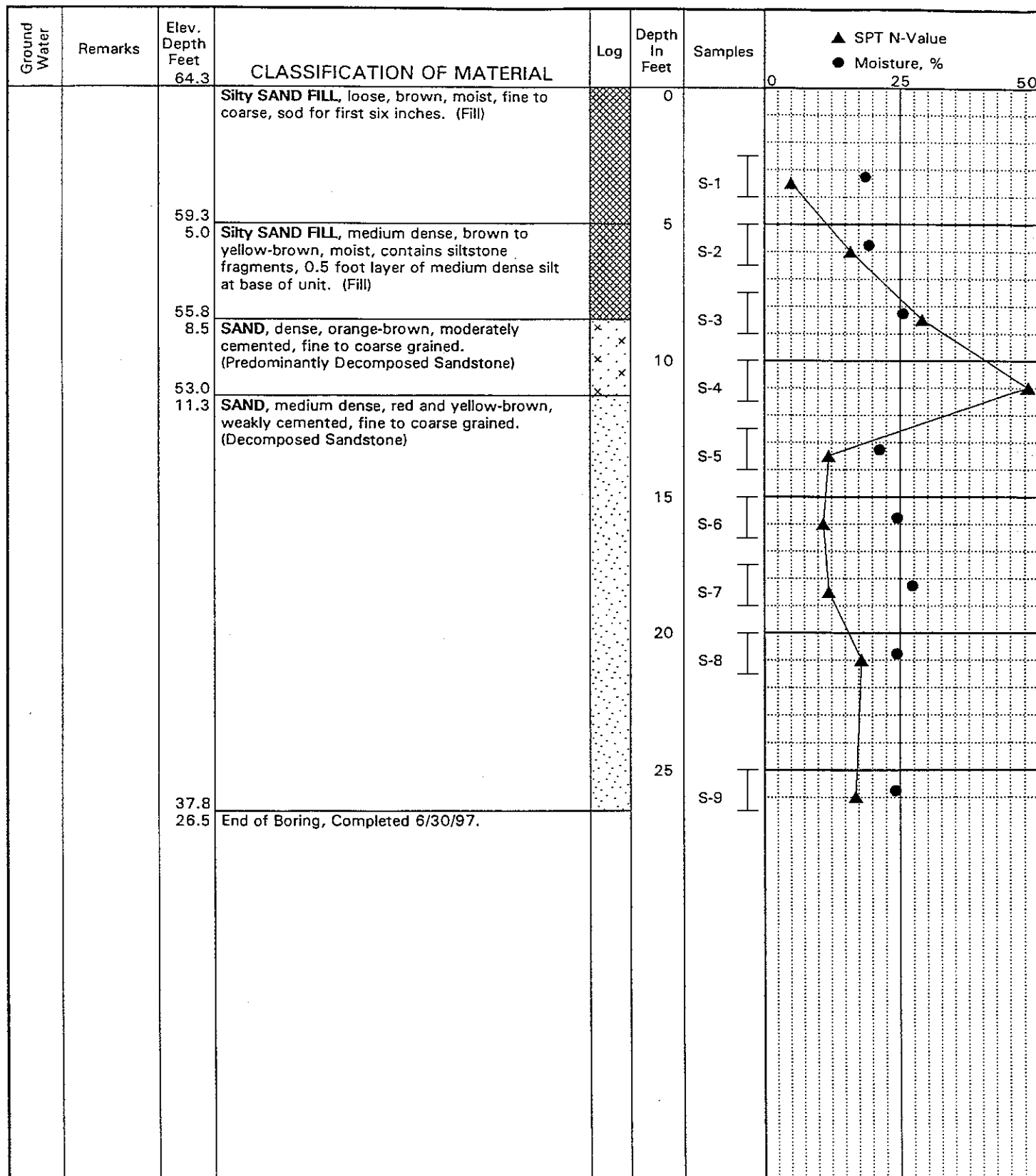
WATER LEVELS Not Encountered

START 11/25/91 1450

FINISH 11/25/91 1615

LOGGER D.P. Lutz

DEPTH BELOW SURFACE (FT)	SAMPLE			STANDARD PENETRATION TEST RESULTS 6" - 6" - 6" (N)	SOIL DESCRIPTION SOIL NAME, USCS GROUP SYMBOL, COLOR, MOISTURE CONTENT, RELATIVE DENSITY OR CONSISTENCY, SOIL STRUCTURE, MINERALOGY	COMMENTS DEPTH OF CASING, DRILLING RATE, DRILLING FLUID LOSS, TESTS AND INSTRUMENTATION
	INTERVAL	TYPE AND NUMBER	RECOVERY INCHES			
5.0	2.5					
	3.0	SS-1	4	50/6"	POORLY GRADED SAND with SILT and GRAVEL, (SP-SM), light to dark brown, gray, moist, loose.	Driller hit rock
	5.0					
	6.5	SS-2	5	5-4-5 (9)	SILTY SAND, (SM), brown and black, moist, loose, trace gravel.	
10.0	7.5					
	9.0	SS-3	2	8-6-6 (12)	POORLY GRADED SAND with SILT, (SP-SM), brown, yellow, and red, moist, medium dense.	4 inches of 1/4-inch gravel slough
	11.0					Driller hit a rock at 9 feet.
	12.5	SS-4		3-3-5 (8)	SILT with SAND, (ML), light brown, few black mottles, moist, firm, fine-grained sand.	Possible native ground
15.0	15.0					
	17.0	ST-5	24	PUSH	SILTY SAND, (SM), light brown, moist.	PP>4
	18.5	SS-6	4	4-8-25 (33)	SILTY SAND, (SM), yellow and yellow-brown with red specks, moist, very dense.	Apparently Troutdale Formation
	20.0					
20.0	20.3	SS-7	2	60/4"	POORLY GRADED SAND, (SP), dark brown and greenish brown, moist, very dense.	
					END OF BORING AT 20.3 FEET 1615 11/25/91	
25.0						



LEGEND

- = 2.0" O.D. Split Spoon Sample
- = 3.0" O.D. Thin-Walled Sample
- = Sample Not Recovered
- ⊗ = Grab Sample: Drill Cuttings
- = Core Rock Sample

NOTE:

Lines between soil/rock units are approximate and transition may be gradual.

- ⊞ Impervious Seal (Bentonite)
- ⊞ Cement Grout
- ⊞ Random Backfill
- ⊞ Granular Backfill
- ⊞ Ground Water Level on Date Shown
- ⊞ Piezometer/Inclinometer Tubing
- ⊞ Perforated Zone

ATTERBERG LIMITS

- Liquid Limit
- Natural Water Content
- Plastic Limit

0 50 100
 □ Recovery, % □ RQD, %

Gresham WWTP Phase I Expansion
 Gresham, Oregon

LOG OF BORING B-1

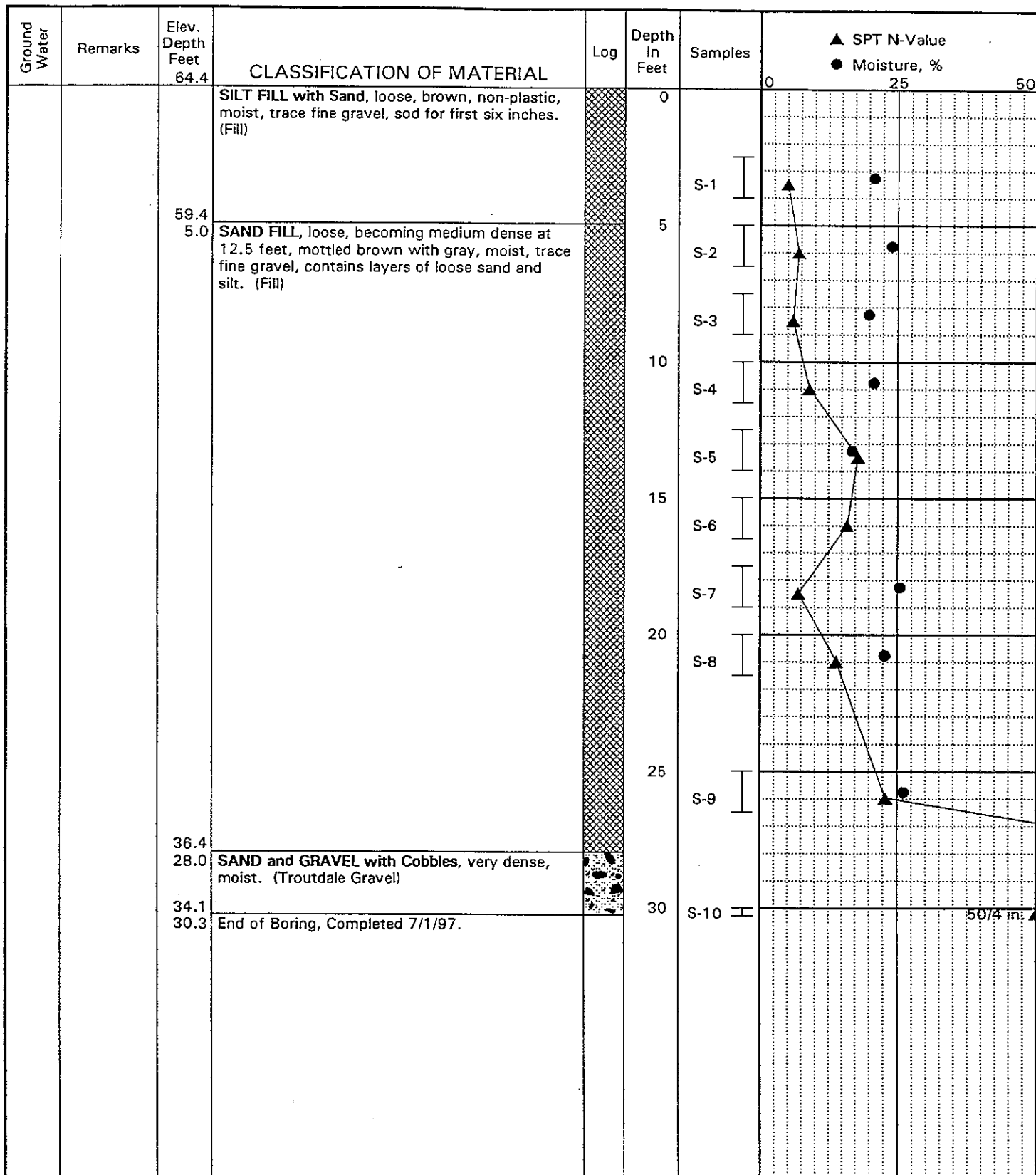
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 Portland, Oregon

FIG. 3



LEGEND

- ⊔ = 2.0" O.D. Split Spoon Sample
- ⊔ = 3.0" O.D. Thin-Walled Sample
- * = Sample Not Recovered
- ⊔ = Grab Sample: Drill Cuttings
- ⊔ = Core Rock Sample

NOTE:

Lines between soil/rock units are approximate and transition may be gradual.

- ⊔ Impervious Seal (Bentonite)
- ⊔ Cement Grout
- ⊔ Random Backfill
- ⊔ Granular Backfill
- ⊔ Ground Water Level on Date Shown
- ⊔ Piezometer/Inclinometer Tubing
- ⊔ Perforated Zone

ATTERBERG LIMITS

- ⊔ Liquid Limit
- ⊔ Natural Water Content
- ⊔ Plastic Limit

0 50 100

Recovery, % RQD, %

Gresham WWTP Phase I Expansion
Gresham, Oregon

LOG OF BORING B-2

page 1 of 1

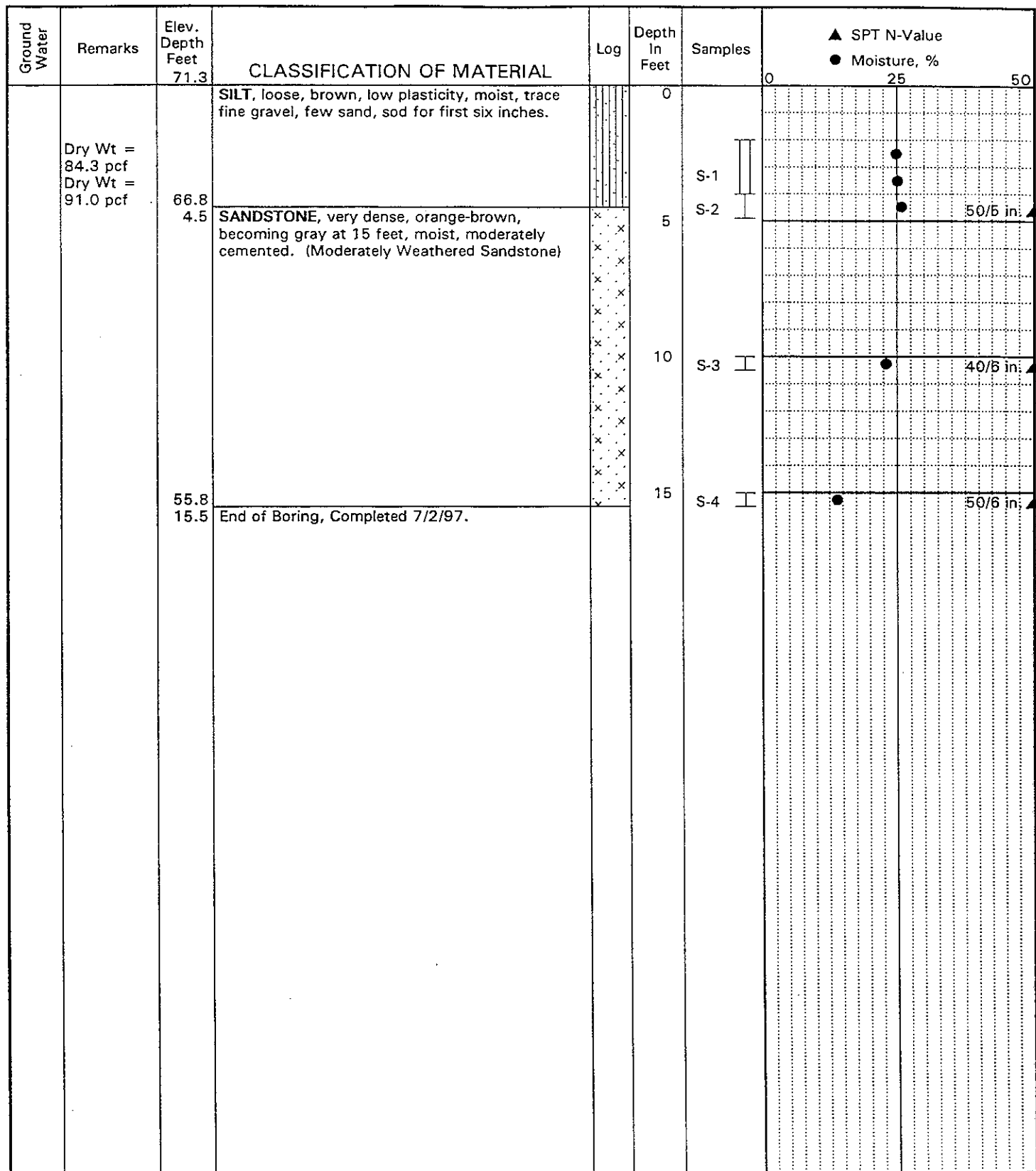
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FIG. 4

FHA



LEGEND

- ⌈ = 2.0" O.D. Split Spoon Sample
- ⌈ = 3.0" O.D. Thin-Walled Sample
- = Sample Not Recovered
- ⊠ = Grab Sample: Drill Cuttings
- = Core Rock Sample

NOTE:

Lines between soil/rock units are approximate and transition may be gradual.

- ⊠ Impervious Seal (Bentonite)
- ⊠ Cement Grout
- ⊠ Random Backfill
- ⊠ Granular Backfill
- ⊠ Ground Water Level on Date Shown
- ⊠ Piezometer/Inclinometer Tubing
- ⊠ Perforated Zone

ATTERBERG LIMITS

- ⌈ Liquid Limit
- ⌈ Natural Water Content
- ⌈ Plastic Limit

Recovery, % RQD, %

Gresham WWTP Phase I Expansion
Gresham, Oregon

LOG OF BORING B-5

page 1 of 1

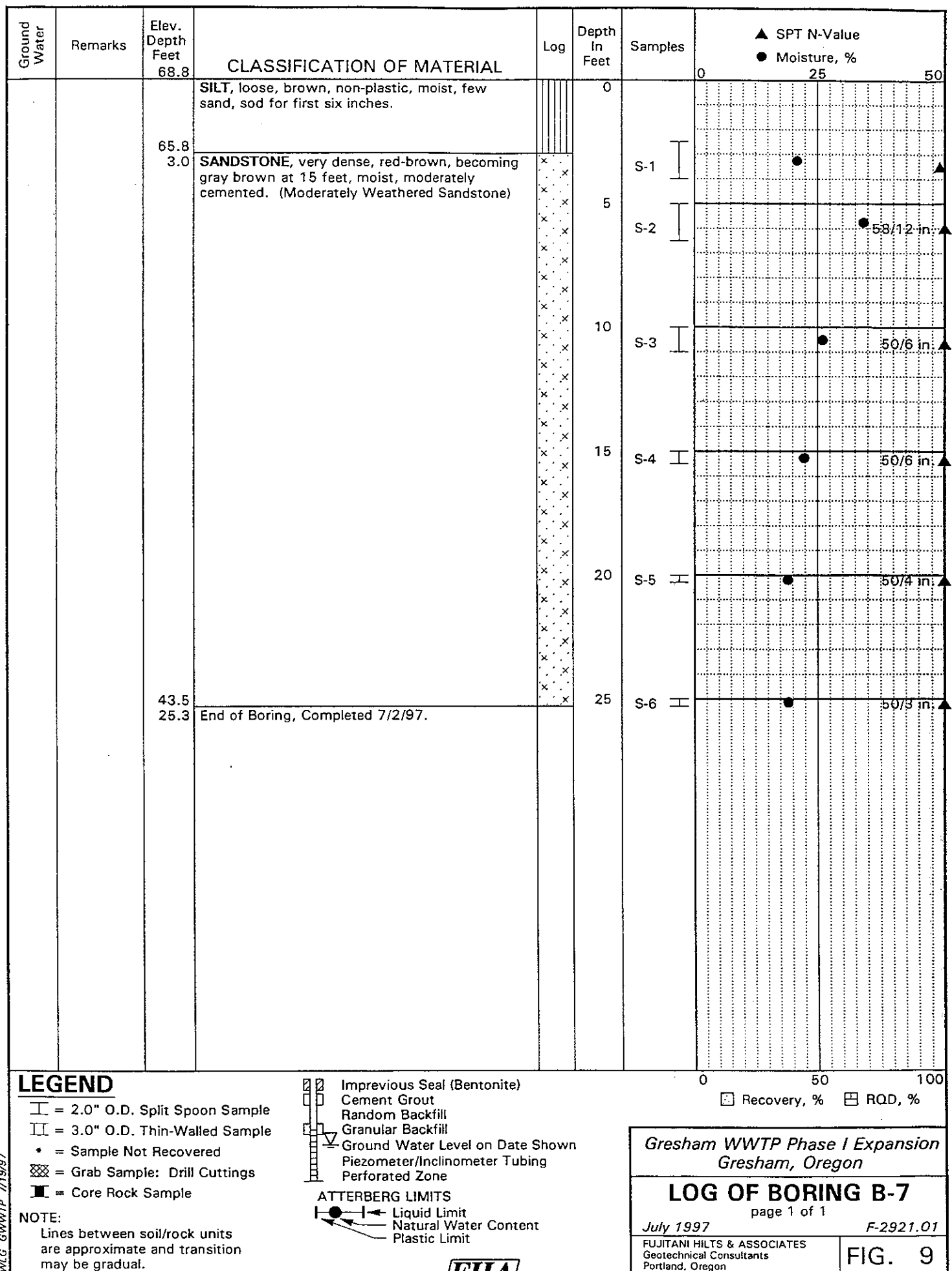
July 1997

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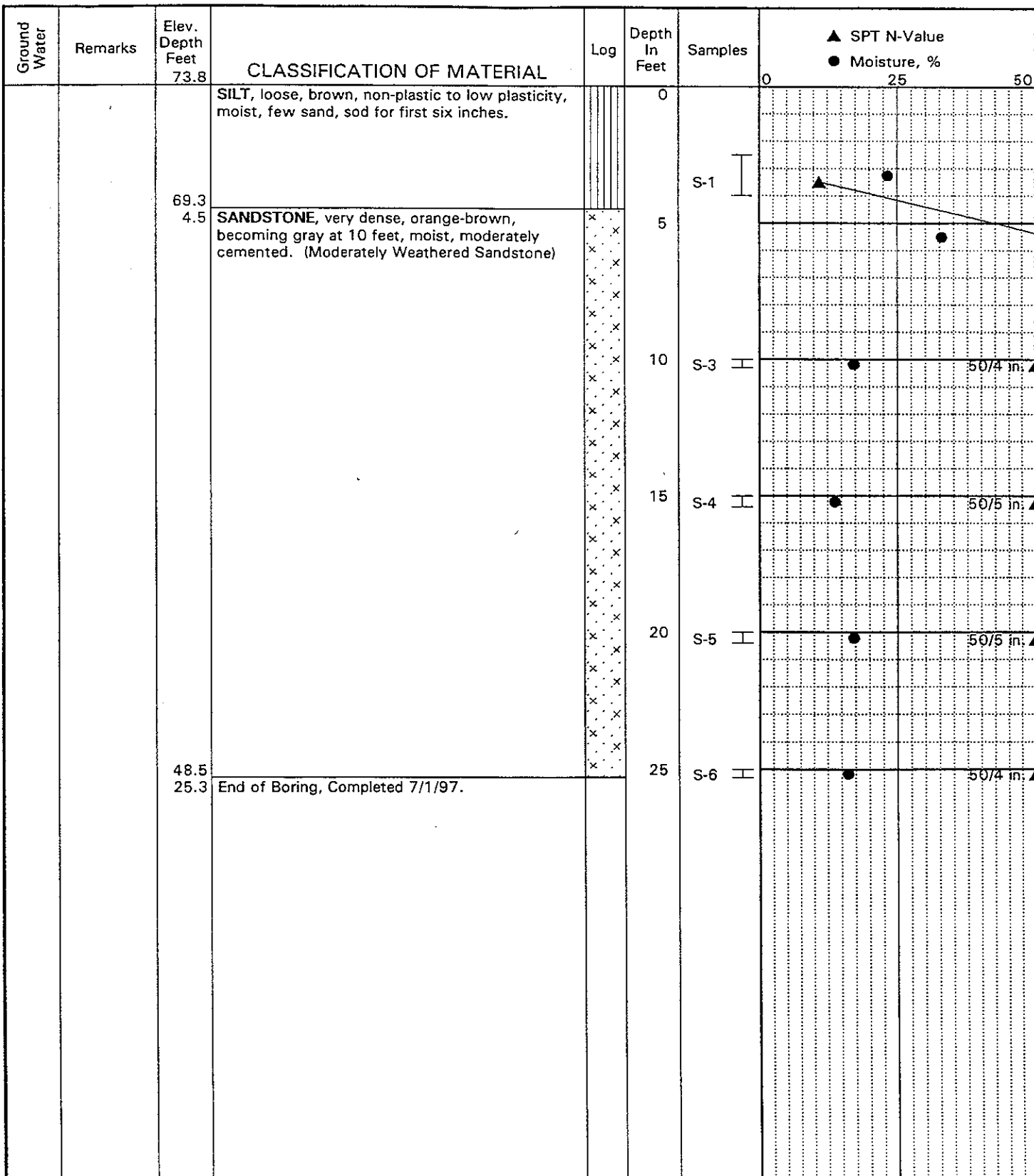
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Portland, Oregon

FIG. 7

FHA



WLG GWWTP 7/19/97



LEGEND

- ⌈ = 2.0" O.D. Split Spoon Sample
- ⌈⌈ = 3.0" O.D. Thin-Walled Sample
- * = Sample Not Recovered
- ⊠ = Grab Sample: Drill Cuttings
- = Core Rock Sample

NOTE:

Lines between soil/rock units are approximate and transition may be gradual.

- ⊠ Impervious Seal (Bentonite)
- ⊠ Cement Grout
- ⊠ Random Backfill
- ⊠ Granular Backfill
- ▽ Ground Water Level on Date Shown
- ⊠ Piezometer/Inclinometer Tubing
- ⊠ Perforated Zone

ATTERBERG LIMITS

- Liquid Limit
- Natural Water Content
- Plastic Limit

0 50 100
 □ Recovery, % □ RQD, %

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 Gresham, Oregon*

LOG OF BORING B-8

page 1 of 1

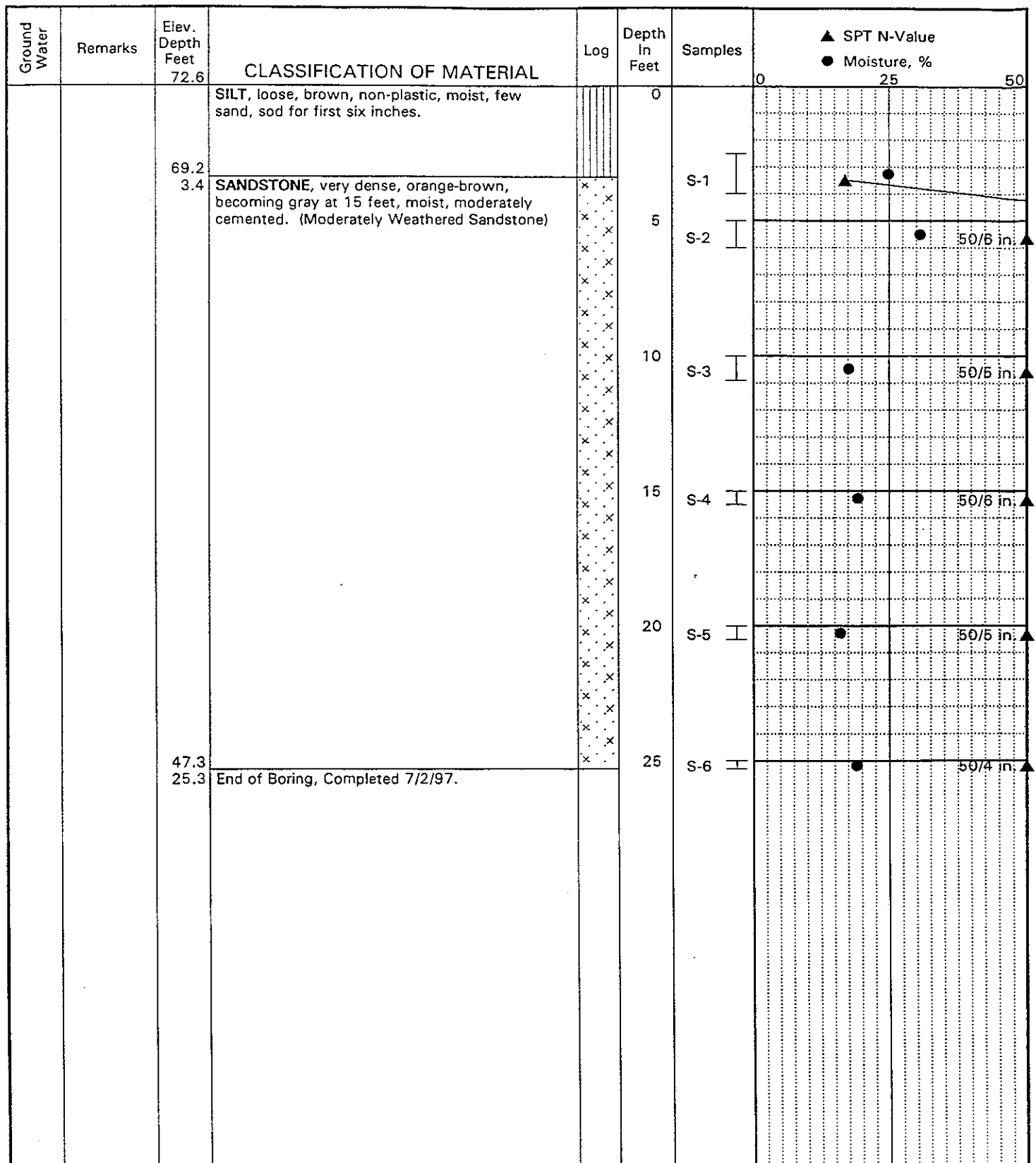
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FIG. 10





LEGEND

- = 2.0" O.D. Split Spoon Sample
- = 3.0" O.D. Thin-Walled Sample
- * = Sample Not Recovered
- = Grab Sample: Drill Cuttings
- = Core Rock Sample

NOTE:

Lines between soil/rock units are approximate and transition may be gradual.

- Impervious Seal (Bentonite)
- Cement Grout
- Random Backfill
- Granular Backfill
- Ground Water Level on Date Shown
- Piezometer/Inclinometer Tubing
- Perforated Zone

ATTERBERG LIMITS

- Liquid Limit
- Natural Water Content
- Plastic Limit

Recovery, % RQD, %

Gresham WWTP Phase I Expansion
Gresham, Oregon

LOG OF BORING B-9

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July 1997

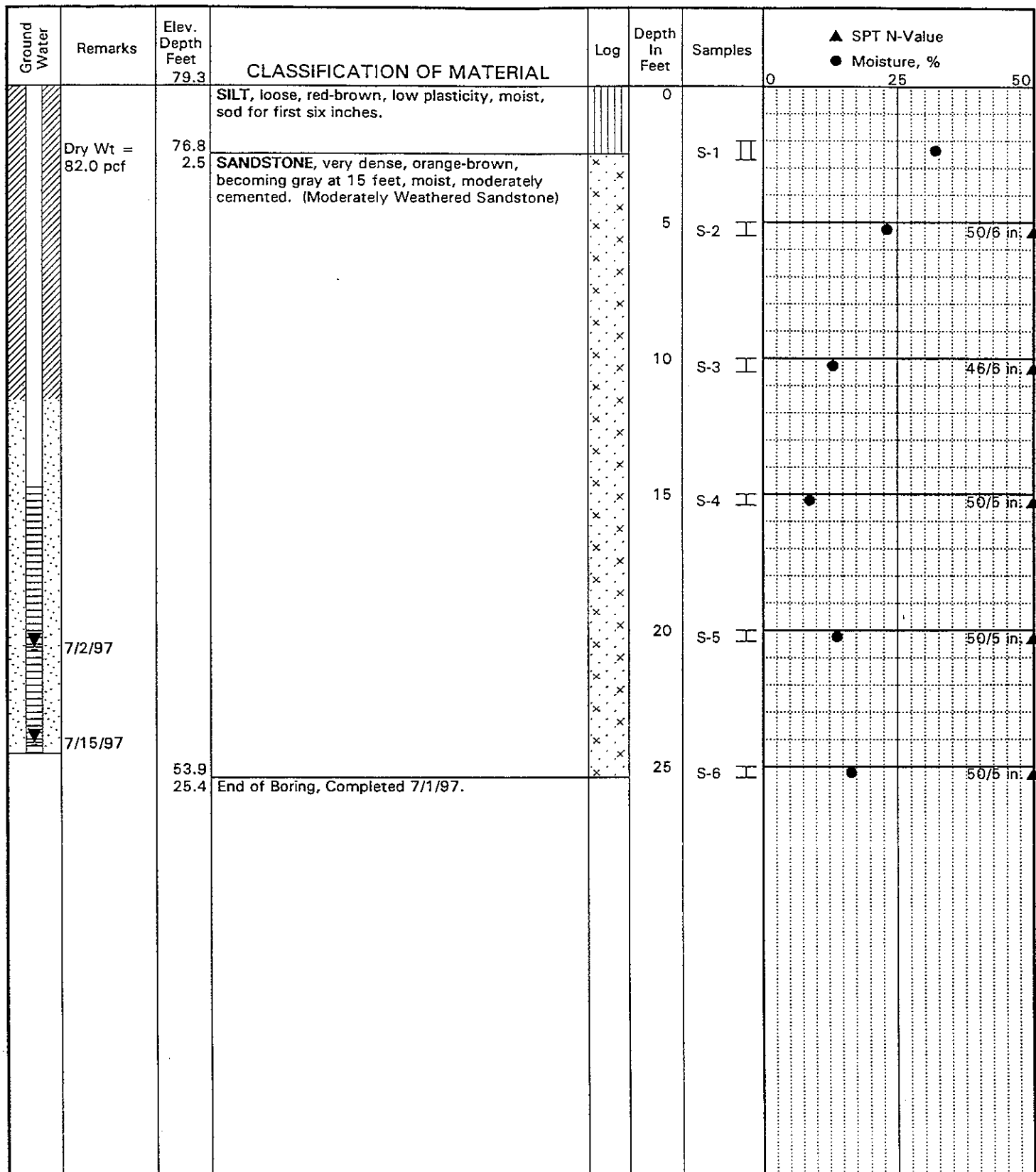
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FIG. 11

FHA

WLG GWWTP 7/19/97



LEGEND

- = 2.0" O.D. Split Spoon Sample
- = 3.0" O.D. Thin-Walled Sample
- = Sample Not Recovered
- ⊗ = Grab Sample: Drill Cuttings
- = Core Rock Sample

NOTE:

Lines between soil/rock units are approximate and transition may be gradual.

- Impervious Seal (Bentonite)
- Cement Grout
- Random Backfill
- Granular Backfill
- Ground Water Level on Date Shown
- Piezometer/Inclinometer Tubing
- Perforated Zone

ATTERBERG LIMITS

- Liquid Limit
- Natural Water Content
- Plastic Limit

0 50 100
Recovery, % RQD, %

Gresham WWTP Phase I Expansion
Gresham, Oregon

LOG OF BORING B-10

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FIG. 12

FHA

Sample Description

Classification of soils in this report is based on visual field and laboratory observations which include density/consistency, moisture condition, grain size, and plasticity estimates and should not be construed to imply field nor laboratory testing unless presented herein. ASTM D 2488 visual-manual identification methods were used as a guide. Major divisions are not necessarily an indicator of soil behavior, which is a function of fines content activity and loading rate.

Relative Density/Consistency

Soil density/consistency in borings is related primarily to the standard penetration resistance (N). Soil density/consistency in test pits and probes is estimated based on visual observation and is presented parenthetically on the logs.

SAND or GRAVEL Relative Density	N (Blows/Foot)	SILT or CLAY Consistency	N (Blows/Foot)
Very loose	0 to 4	Very soft	0 to 2
Loose	4 to 10	Soft	2 to 4
Medium dense	10 to 30	Medium stiff	4 to 8
Dense	30 to 50	Stiff	8 to 15
Very dense	>50	Very stiff	15 to 30
		Hard	>30

Moisture

Dry	Absence of moisture, dusty, dry to the touch
Moist	Damp but no visible water
Wet	Visible free water, usually soil is below water table

Soil Classification Chart

Major Divisions		Symbols		Typical Descriptions
		Graph	USCS	
Coarse Grained Soils More than 50% of Material Retained on No. 200 Sieve	Gravel and Gravelly Soils More than 50% of Coarse Fraction Retained on No. 4 Sieve	Clean Gravels (<5% fines)	GW	Well-Graded Gravel; Well-Graded Gravel with Sand
			GP	Poorly Graded Gravel; Poorly Graded Gravel with Sand
		Gravels (10% fines)	GW-GM	Well-Graded Gravel with Silt; Well-Graded Gravel with Silt and Sand
			GW-GC	Well-Graded Gravel with Clay; Well-Graded Gravel with Clay and Sand
			GP-GM	Poorly Graded Gravel with Silt; Poorly Graded Gravel with Silt and Sand
			GP-GC	Poorly Graded Gravel with Clay; Poorly Graded Gravel with Clay and Sand
	Gravels with Fines (>12% fines)		GM	Silty Gravel; Silty Gravel with Sand
			GC	Clayey Gravel; Clayey Gravel with Sand
	Sand and Sandy Soils More than 50% of Coarse Fraction Passing No. 4 Sieve	Sands with few Fines (<5% fines)	SW	Well-Graded Sand; Well-Graded Sand with Gravel
			SP	Poorly Graded Sand; Poorly Graded Sand with Gravel
		Sands (10% fines)	SW-SM	Well-Graded Sand with Silt Well-Graded Sand with Silt and Gravel
			SW-SC	Well-Graded Sand with Clay; Well-Graded Sand with Clay and Gravel
			SP-SM	Poorly Graded Sand with Silt; Poorly Graded Sand with Silt and Gravel
			SP-SC	Poorly Graded Sand with Clay; Poorly Graded Sand with Clay and Gravel
Fine Grained Soils More than 50% of Material Passing No. 200 Sieve	Silt		SM	Silty Sand; Silty Sand with Gravel
			SC	Clayey Sand; Clayey Sand with Gravel
	Clays		ML	Silt; Silt with Sand or Gravel; Sandy or Gravelly Silt
			MH	Elastic Silt; Elastic Silt with Sand or Gravel; Sandy or Gravelly Elastic Silt
			CL	Lean Clay; Lean Clay with Sand or Gravel; Sandy or Gravelly Lean Clay
			CH	Fat Clay; Fat Clay with Sand or Gravel; Sandy or Gravelly Fat Clay
Highly Organic	Organics		OL/OH	Organic Soil; Organic Soil with Sand or Gravel; Sandy or Gravelly Organic Soil
			PT	Peat - Decomposing Vegetation - Fibrous to Amorphous Texture

Minor Constituents

Estimated Percentage

Trace	<5
Few	5 - 10
Little	15 - 25
Some	30 - 45

Soil Test Symbols

%F	Percent Passing No. 200 Sieve
AL	Atterberg Limits
	Water Content in Percent
	Liquid Limit
	Natural
	Plastic Limit
CA	Chemical Analysis
CAUC	Consolidated Anisotropic Undrained Compression
CAUE	Consolidated Anisotropic Undrained Extension
CBR	California Bearing Ratio
CIDC	Consolidated Drained Isotropic Triaxial Compression
CIUC	Consolidated Isotropic Undrained Compression
CK0DC	Consolidated Drained k0 Triaxial Compression
CK0DSS	Consolidated k0 Undrained Direct Simple Shear
CK0UC	Consolidated k0 Undrained Compression
CK0UE	Consolidated k0 Undrained Extension
CRSCN	Constant Rate of Strain Consolidation
DSS	Direct Simple Shear
DT	In Situ Density
GS	Grain Size Classification
HYD	Hydrometer
ILCN	Incremental Load Consolidation
K0CN	k0 Consolidation
kc	Constant Head Permeability
kf	Falling Head Permeability
MD	Moisture Density Relationship
OC	Organic Content
OT	Tests by Others
P	Pressuremeter
PID	Photoionization Detector Reading
PP	Pocket Penetrometer
SG	Specific Gravity
TRS	Torsional Ring Shear
TV	Torvane
UC	Unconfined Compression
UUC	Unconsolidated Undrained Triaxial Compression
VS	Vane Shear
WC	Water Content

Groundwater Indicators

	Groundwater Level on Date or At Time of Drilling (ATD)
	Groundwater Seepage (Test Pits)

Sample Symbols

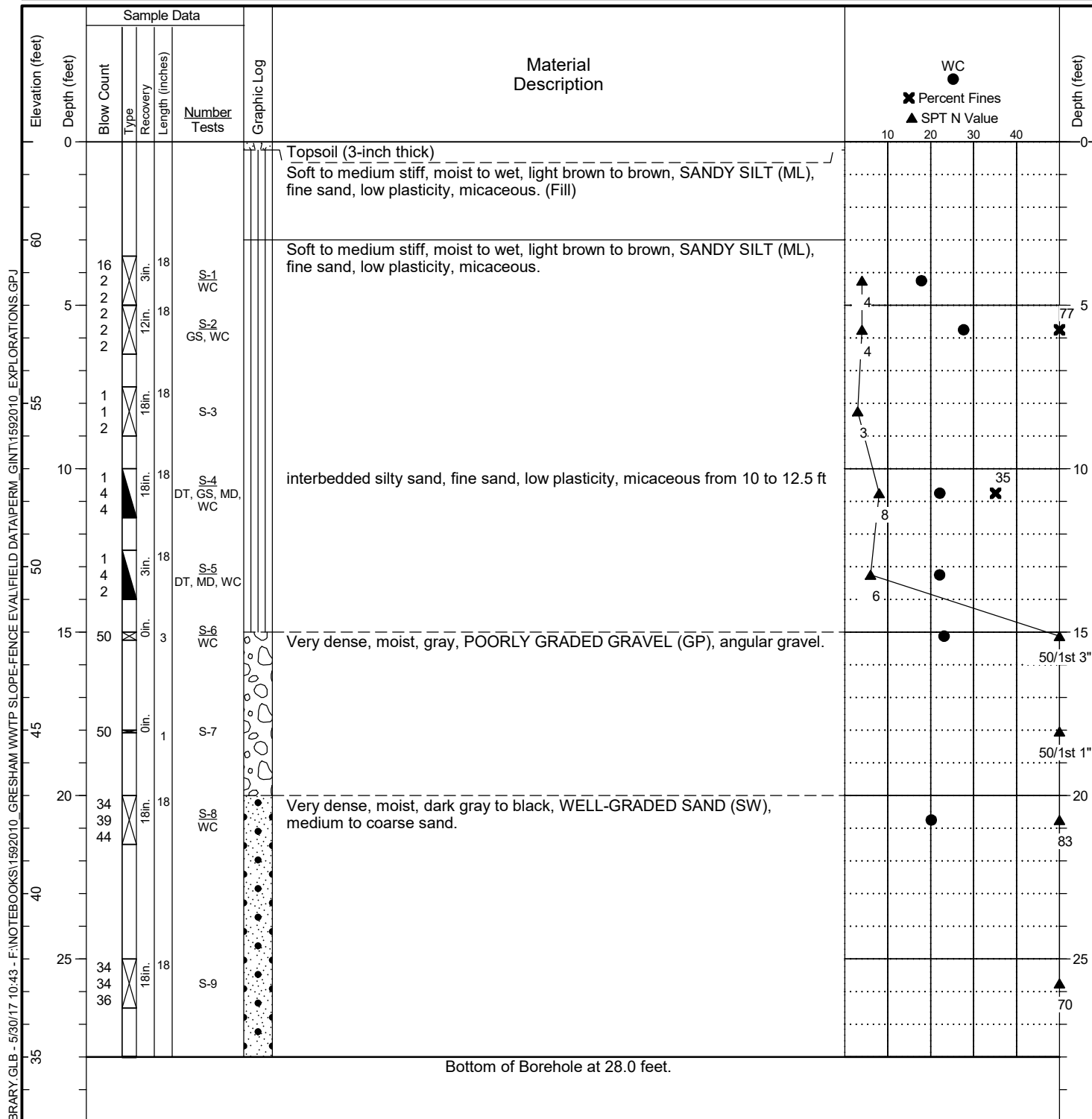
	1.5\"/>		Core Run		Grab
	3.0\"/>		Sonic Core		Cuttings
	Modified California Sampler		Thin-walled Sampler		

Well Symbols

Monument	
Surface Seal	
Bentonite Seal	
Well Casing	
Sand Pack	
Well Tip or Slotted Screen	
Slough	

Date Started: 4/24/17 Date Completed: 4/24/17
 Logged by: J. Robinson Checked by: T. Blackwood
 Location: N: 691,855.26 E: 7,700,762.15
 Ground Surface Elevation: 63 feet
 Horizontal Datum: OR State Plane N, NAD 83, ft.
 Vertical Datum: NAVD 88
 Comments:

Drilling Contractor/Crew: Western States Soil Conservation, Inc.
 Drilling Method: Mud Rotary
 Rig Model/Type: CME-75 / Truck-mounted
 Hammer Type: Auto-hammer
 Hammer Weight (pounds): 140 Hammer Drop Height (inches): 30
 Hammer Efficiency (%): Measured: 60 Estimated: 80%
 Auger Diameter: 3.625 inches Casing Diameter: NA
 Total Depth: 28 feet Depth to Ground Water: Not Identified



General Notes:

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Material descriptions and stratum lines are interpretive and actual changes may be gradual. Solid stratum lines indicate distinct contact between material strata or geologic units. Dashed stratum lines indicate gradual or approximate change between material strata or geologic units.
3. USCS designations are based on visual-manual identification (ASTM D 2488) unless otherwise supported by laboratory testing (ASTM D 2487).
4. Groundwater level, if indicated, is at time of drilling/excavation (ATD) or for date specified. Level may vary with time.

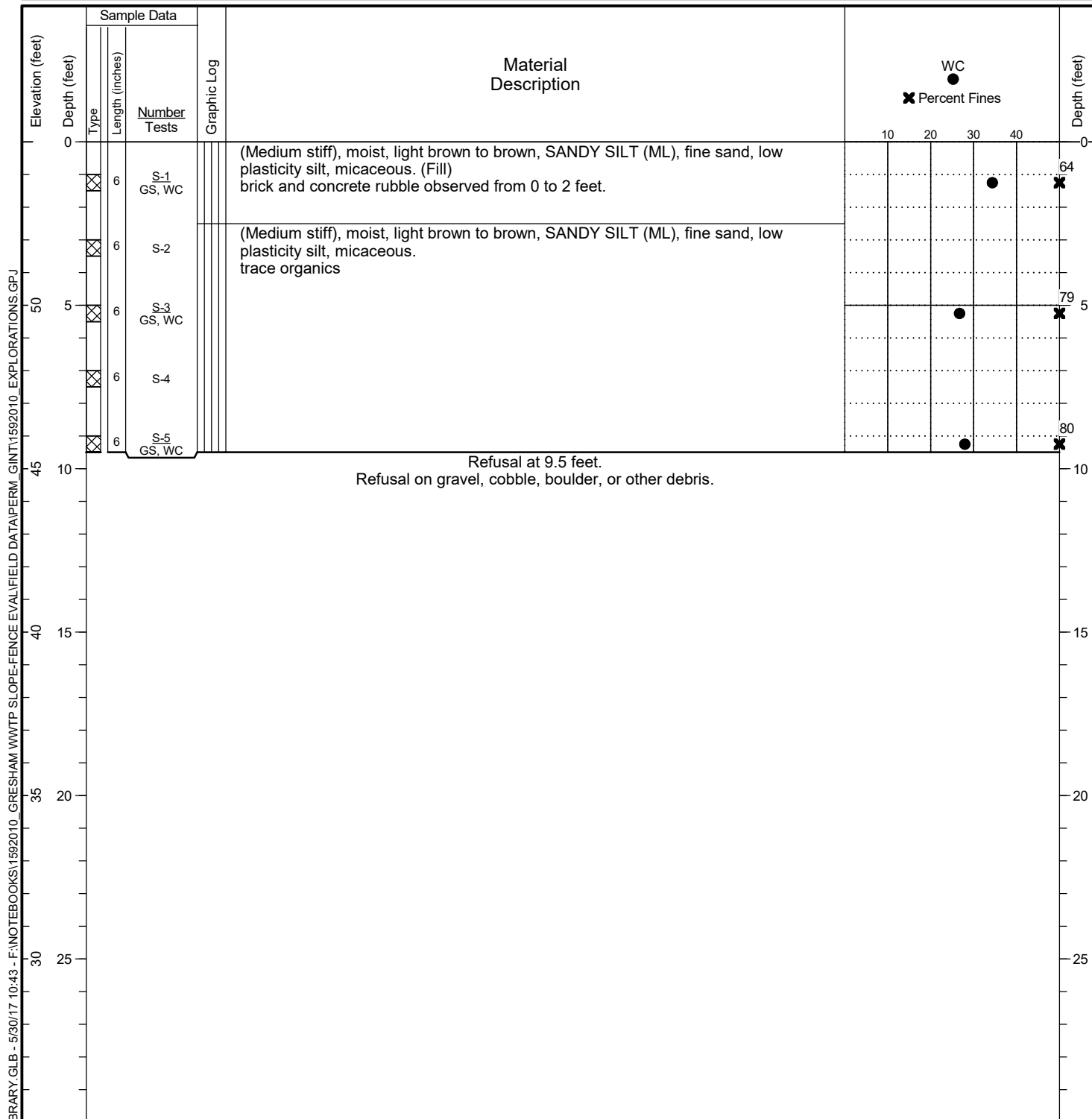


Project: Gresham WWTP Slope Evaluation
 Location: Gresham, Oregon
 Project No.: 15920-10

Boring Log
 HC-1

Figure A-2
 Sheet 1 of 1

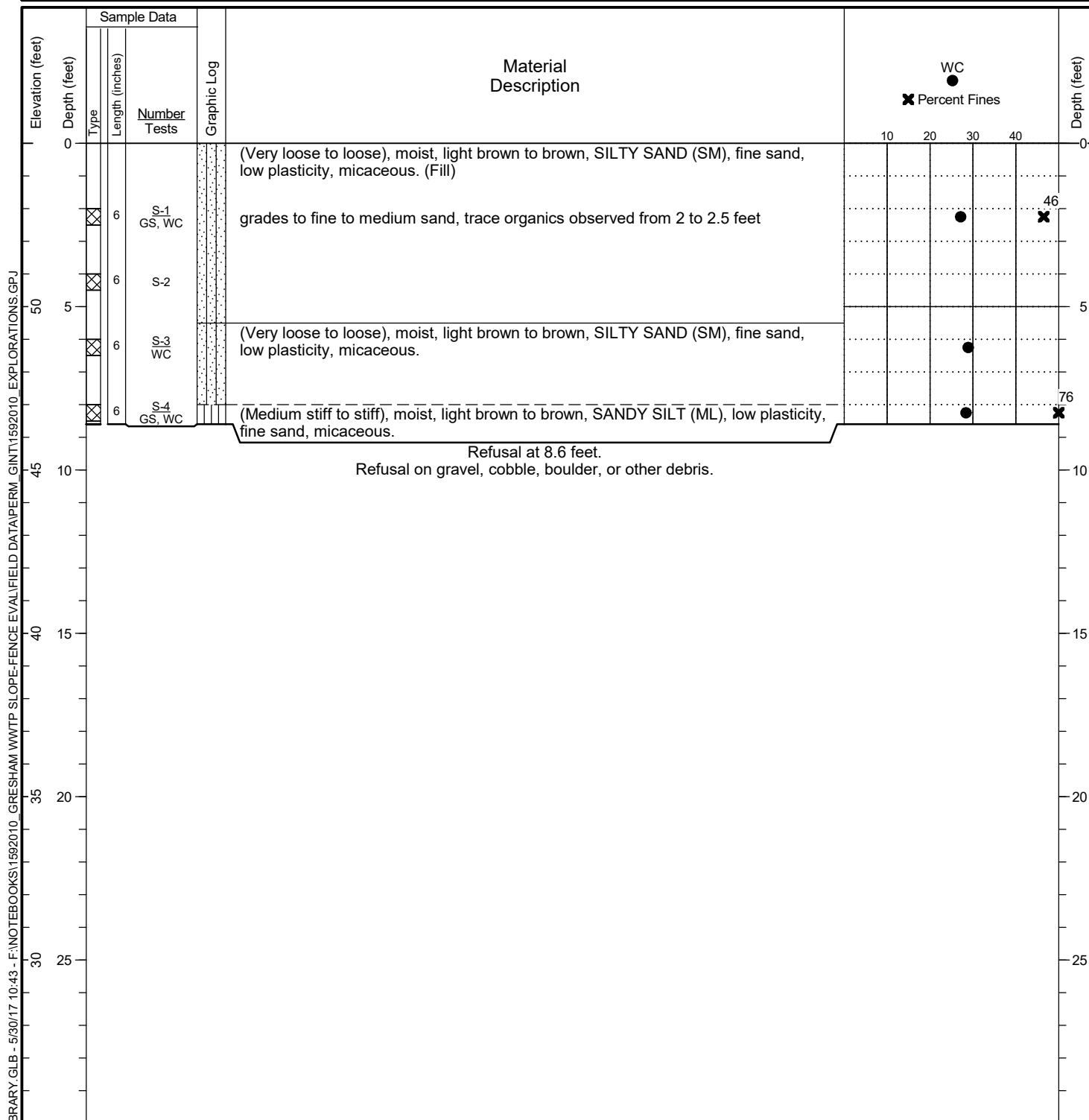
Date Started: 4/24/17	Date Completed: 4/24/17	Drilling Contractor/Crew: Hart Crowser
Logged by: J. Robinson	Checked by: T. Blackwood	Drilling Method: Hand Auger
Location: N: 691,895.73 E: 7,700,778.41		Rig Model/Type: NA
Ground Surface Elevation: 55 feet		Hammer Type: NA
Horizontal Datum: OR State Plane N, NAD 83, ft.		Hammer Weight (pounds): NA Hammer Drop Height (inches): NA
Vertical Datum: NAVD 88		Hammer Efficiency (%): Measured: NA Estimated: NA
Comments:		Auger Diameter: 4 inches Casing Diameter: NA
		Total Depth: 9.5 feet Depth to Ground Water: Not Identified



General Notes:

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Material descriptions and stratum lines are interpretive and actual changes may be gradual. Solid stratum lines indicate distinct contact between material strata or geologic units. Dashed stratum lines indicate gradual or approximate change between material strata or geologic units.
3. USCS designations are based on visual-manual identification (ASTM D 2488) unless otherwise supported by laboratory testing (ASTM D 2487).
4. Groundwater level, if indicated, is at time of drilling/excavation (ATD) or for date specified. Level may vary with time.

Date Started: 4/24/17	Date Completed: 4/24/17	Drilling Contractor/Crew: Hart Crowser
Logged by: J. Robinson	Checked by: T. Blackwood	Drilling Method: Hand Auger
Location: N: 691,903.99 E: 7,700,740.45		Rig Model/Type: NA
Ground Surface Elevation: 55 feet		Hammer Type: NA
Horizontal Datum: OR State Plane N, NAD 83, ft.		Hammer Weight (pounds): NA Hammer Drop Height (inches): NA
Vertical Datum: NAVD 88		Hammer Efficiency (%): Measured: NA Estimated: NA
Comments:		Auger Diameter: 4 inches Casing Diameter: NA
		Total Depth: 8.6 feet Depth to Ground Water: Not Identified



General Notes:

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Material descriptions and stratum lines are interpretive and actual changes may be gradual. Solid stratum lines indicate distinct contact between material strata or geologic units. Dashed stratum lines indicate gradual or approximate change between material strata or geologic units.
3. USCS designations are based on visual-manual identification (ASTM D 2488) unless otherwise supported by laboratory testing (ASTM D 2487).
4. Groundwater level, if indicated, is at time of drilling/excavation (ATD) or for date specified. Level may vary with time.



Project: Gresham WWTP Slope Evaluation
Location: Gresham, Oregon
Project No.: 15920-10

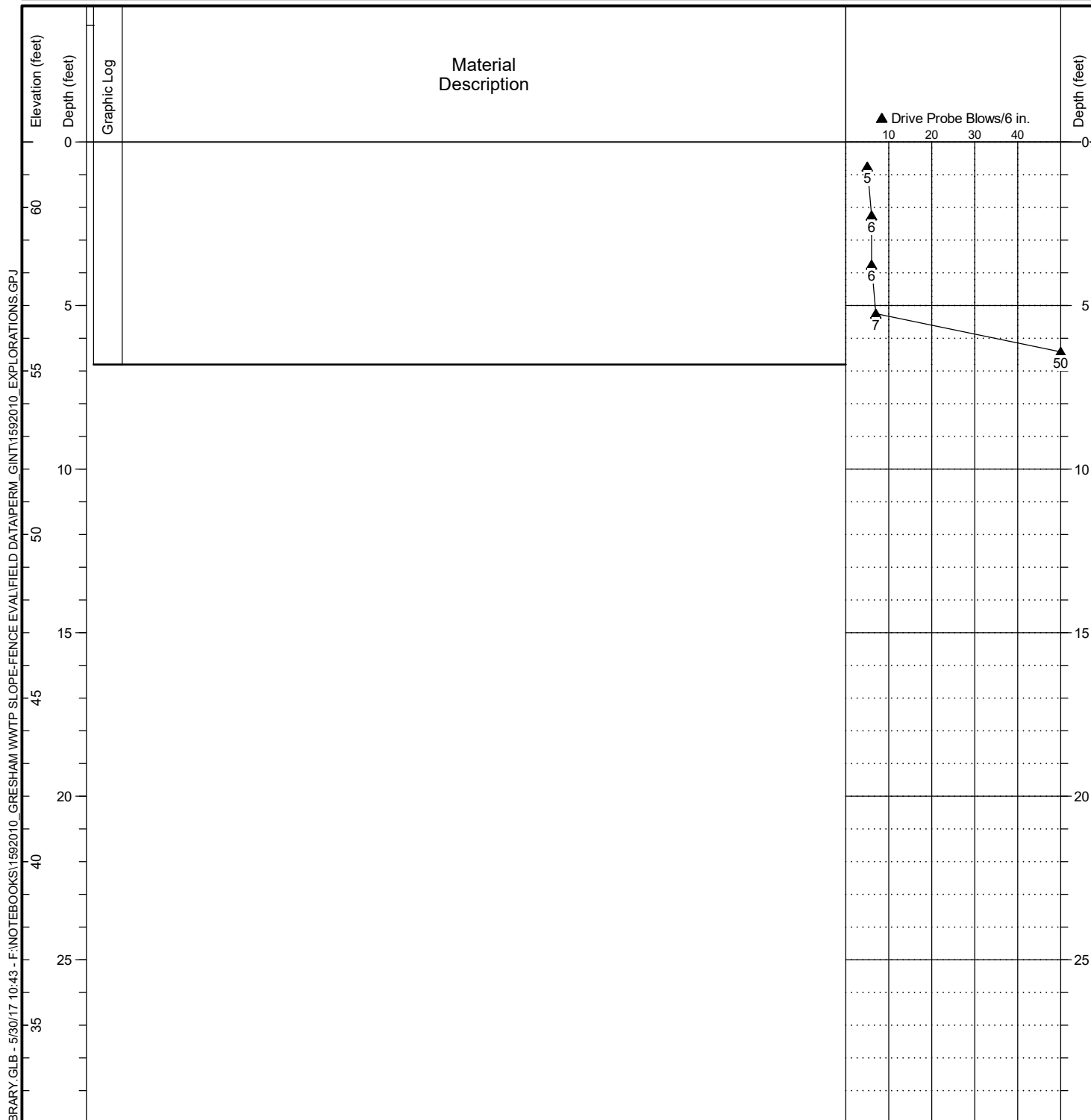
Hand-Auger Log
HA-2

Figure **A-4**
Sheet **1 of 1**

HC BORING LOG - F:\GINT\HC LIBRARY\GLB - 5/30/17 10:43 - F:\NOTEBOOKS\15920-10 - GRESHAM WWTP SLOPE-FENCE EVAL\FIELD DATA\PERM_GINT\15920-10_EXPLORATIONS.GPJ

Date Started: 5/9/17 Date Completed: 5/9/17
 Logged by: J. Robinson Checked by: T. Blackwood
 Location: N: 691,887.88 E: 7,700,733.91
 Ground Surface Elevation: 62 feet
 Horizontal Datum: OR State Plane N, NAD 83, ft.
 Vertical Datum: NAVD 88
 Comments: _____

Drilling Contractor/Crew: Hart Crowser
 Drilling Method: Drive Probe
 Rig Model/Type: USDA Forest Service Probe
 Hammer Type: Manual
 Hammer Weight (pounds): 12 Hammer Drop Height (inches): 39
 Hammer Efficiency (%): Measured: NA Estimated: NA
 Auger Diameter: 0.25 inches Casing Diameter: NA
 Total Depth: 6.8 feet Depth to Ground Water: Not Identified



General Notes:

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Material descriptions and stratum lines are interpretive and actual changes may be gradual. Solid stratum lines indicate distinct contact between material strata or geologic units. Dashed stratum lines indicate gradual or approximate change between material strata or geologic units.
3. USCS designations are based on visual-manual identification (ASTM D 2488) unless otherwise supported by laboratory testing (ASTM D 2487).
4. Groundwater level, if indicated, is at time of drilling/excavation (ATD) or for date specified. Level may vary with time.



Project: Gresham WWTP Slope Evaluation
 Location: Gresham, Oregon
 Project No.: 15920-10

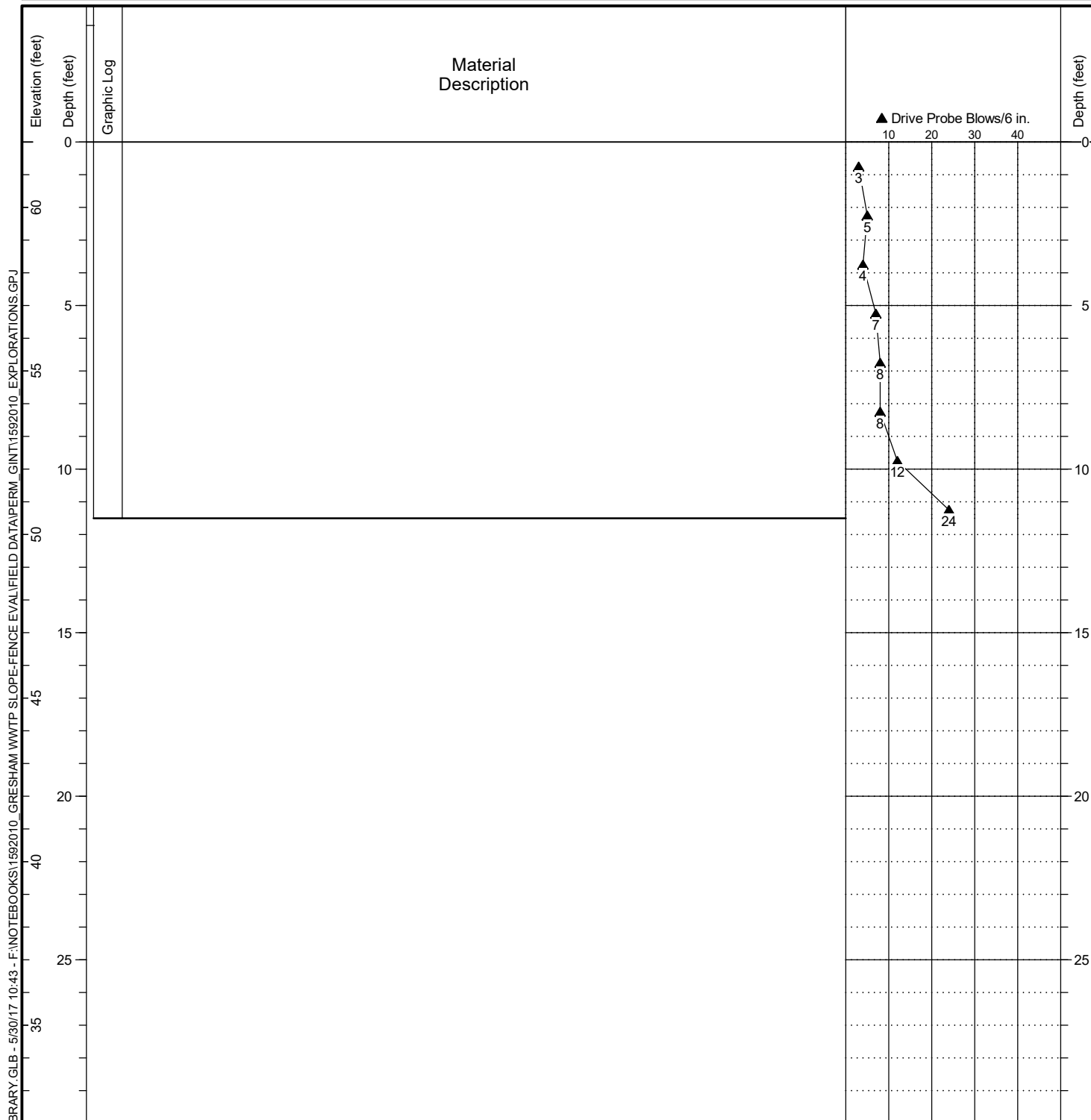
Drive Probe Log
DP-1

Figure **A-5**
 Sheet **1 of 1**

HC BORING LOG - F:\GINT\HC LIBRARY\GLB - 5/30/17 10:43 - F:\NOTEBOOKS\15920\10 - GRESHAM WWTP SLOPE-FENCE EVAL\FIELD DATA\PERM_GINT\15920\10 - EXPLORATIONS.GPJ

Date Started: 5/9/17 Date Completed: 5/9/17
 Logged by: J. Robinson Checked by: T. Blackwood
 Location: N: 691,885.31 E: 7,700,748.68
 Ground Surface Elevation: 62 feet
 Horizontal Datum: OR State Plane N, NAD 83, ft.
 Vertical Datum: NAVD 88
 Comments: _____

Drilling Contractor/Crew: Hart Crowser
 Drilling Method: Drive Probe
 Rig Model/Type: USDA Forest Service Probe
 Hammer Type: Manual
 Hammer Weight (pounds): 12 Hammer Drop Height (inches): 39
 Hammer Efficiency (%): Measured: NA Estimated: NA
 Auger Diameter: 0.25 inches Casing Diameter: NA
 Total Depth: 11.5 feet Depth to Ground Water: Not Identified



General Notes:

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Material descriptions and stratum lines are interpretive and actual changes may be gradual. Solid stratum lines indicate distinct contact between material strata or geologic units. Dashed stratum lines indicate gradual or approximate change between material strata or geologic units.
3. USCS designations are based on visual-manual identification (ASTM D 2488) unless otherwise supported by laboratory testing (ASTM D 2487).
4. Groundwater level, if indicated, is at time of drilling/excavation (ATD) or for date specified. Level may vary with time.



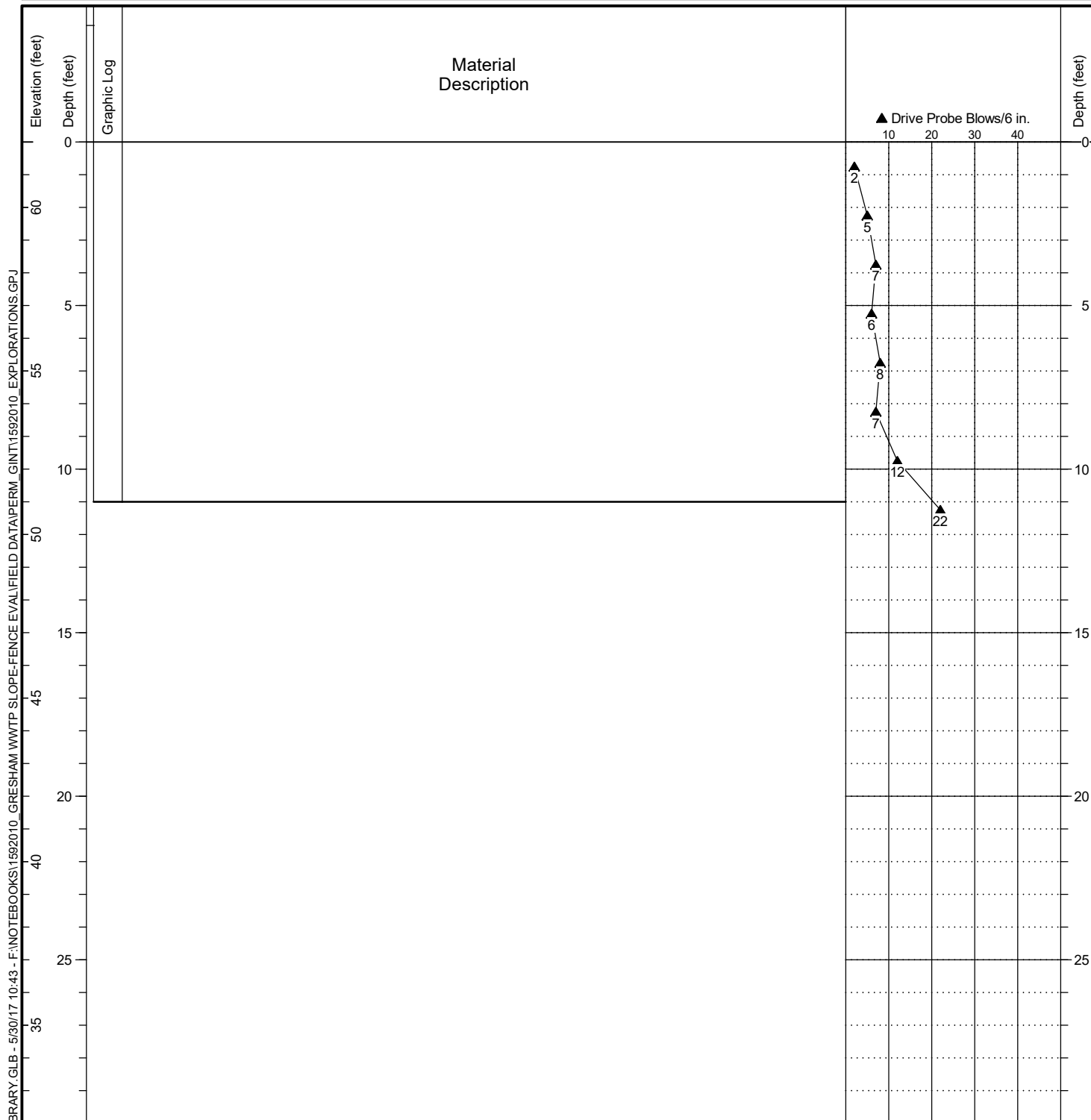
Project: Gresham WWTP Slope Evaluation
 Location: Gresham, Oregon
 Project No.: 15920-10

Drive Probe Log
DP-2

Figure **A-6**
 Sheet **1 of 1**

Date Started: 5/9/17 Date Completed: 5/9/17
 Logged by: J. Robinson Checked by: T. Blackwood
 Location: N: 691,881.84 E: 7,700,763.35
 Ground Surface Elevation: 62 feet
 Horizontal Datum: OR State Plane N, NAD 83, ft.
 Vertical Datum: NAVD 88
 Comments: _____

Drilling Contractor/Crew: Hart Crowser
 Drilling Method: Drive Probe
 Rig Model/Type: USDA Forest Service Probe
 Hammer Type: Manual
 Hammer Weight (pounds): 12 Hammer Drop Height (inches): 39
 Hammer Efficiency (%): Measured: NA Estimated: NA
 Auger Diameter: 0.25 inches Casing Diameter: NA
 Total Depth: 11 feet Depth to Ground Water: Not Identified



General Notes:

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Material descriptions and stratum lines are interpretive and actual changes may be gradual. Solid stratum lines indicate distinct contact between material strata or geologic units. Dashed stratum lines indicate gradual or approximate change between material strata or geologic units.
3. USCS designations are based on visual-manual identification (ASTM D 2488) unless otherwise supported by laboratory testing (ASTM D 2487).
4. Groundwater level, if indicated, is at time of drilling/excavation (ATD) or for date specified. Level may vary with time.



Project: Gresham WWTP Slope Evaluation
 Location: Gresham, Oregon
 Project No.: 15920-10

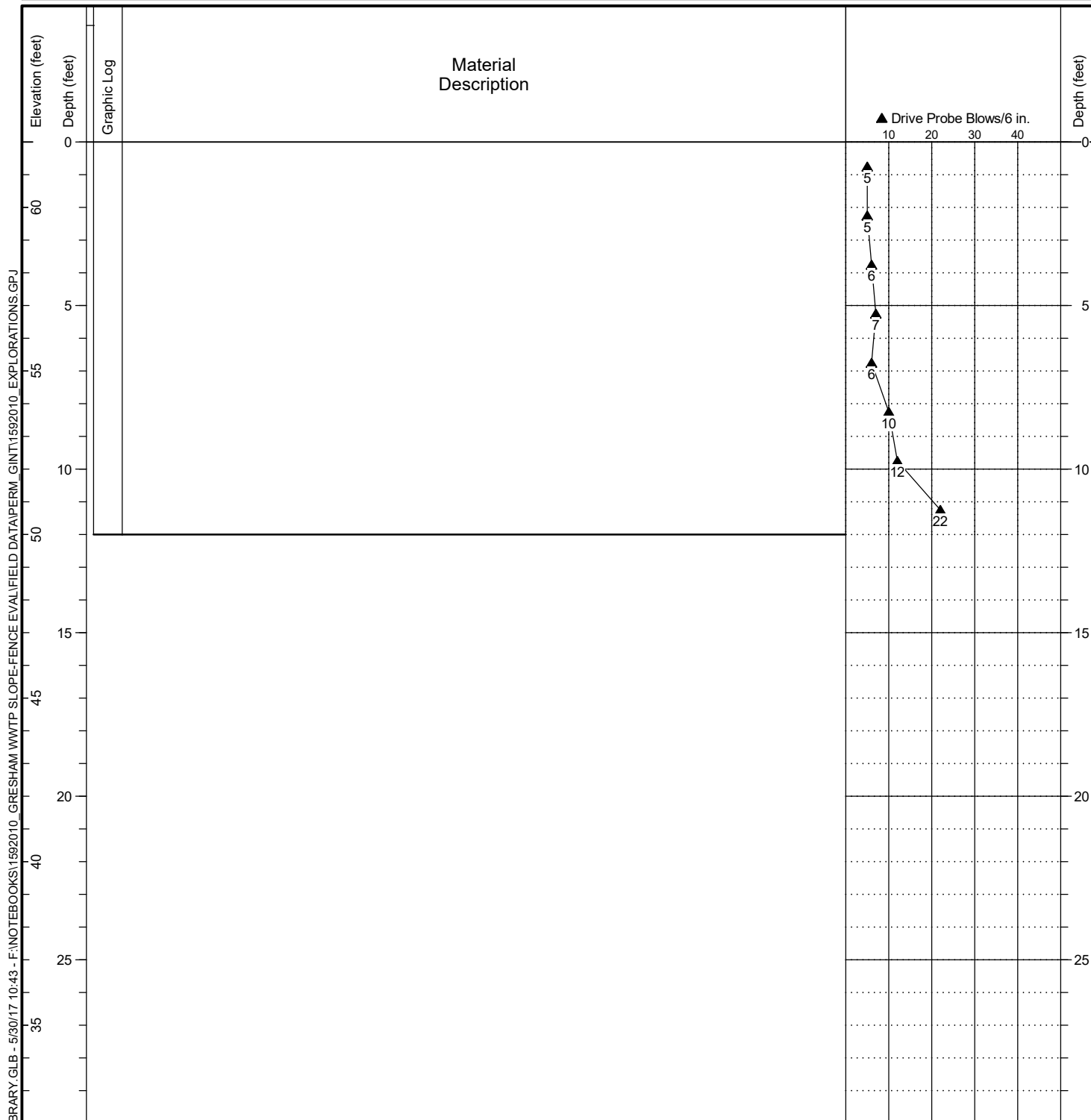
Drive Probe Log
DP-3

Figure **A-7**
 Sheet **1 of 1**

HC BORING LOG - F:\GINT\HC LIBRARY\GLB - 5/30/17 10:43 - F:\NOTEBOOKS\15920-10 - GRESHAM WWTP SLOPE-FENCE EVAL\FIELD DATA\PERM_GINT\15920-10_EXPLORATIONS.GPJ

Date Started: 5/9/17 Date Completed: 5/9/17
 Logged by: J. Robinson Checked by: T. Blackwood
 Location: N: 691,877.93 E: 7,700,776.94
 Ground Surface Elevation: 62 feet
 Horizontal Datum: OR State Plane N, NAD 83, ft.
 Vertical Datum: NAVD 88
 Comments: _____

Drilling Contractor/Crew: Hart Crowser
 Drilling Method: Drive Probe
 Rig Model/Type: USDA Forest Service Probe
 Hammer Type: Manual
 Hammer Weight (pounds): 12 Hammer Drop Height (inches): 39
 Hammer Efficiency (%): Measured: NA Estimated: NA
 Auger Diameter: 0.25 inches Casing Diameter: NA
 Total Depth: 12 feet Depth to Ground Water: Not Identified



General Notes:

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Material descriptions and stratum lines are interpretive and actual changes may be gradual. Solid stratum lines indicate distinct contact between material strata or geologic units. Dashed stratum lines indicate gradual or approximate change between material strata or geologic units.
3. USCS designations are based on visual-manual identification (ASTM D 2488) unless otherwise supported by laboratory testing (ASTM D 2487).
4. Groundwater level, if indicated, is at time of drilling/excavation (ATD) or for date specified. Level may vary with time.



Project: Gresham WWTP Slope Evaluation
 Location: Gresham, Oregon
 Project No.: 15920-10

Drive Probe Log
DP-4

Figure **A-8**
 Sheet **1 of 1**

2020 SW 4th Avenue, 3rd Floor
Portland, Oregon 97201
(503) 235-5000 F +1.214.638.0447
www.jacobs.com

Subject	Heating, Ventilation, and Air Conditioning, Plumbing, and Fire Protection
Project Name	City of Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project
Jacobs Project Number	D3621900
To	Rob Chapler/City of Gresham
From	Jim Sackinger, P.E.
Reviewed by	Patrick Rausch, P.E.
Date	March 7, 2023

1. Introduction

The purpose of this technical memorandum is to define requirements for; plumbing; heating, ventilation, and air conditioning (HVAC); and fire protection for the City of Gresham Wastewater Treatment Plant (WWTP) Anaerobic Digestion and Cogeneration Expansion Project.

2. Applicable Codes, Standards, and Regulations

The following codes and standards apply to this project:

- 2014 Oregon Structural Specialty Code
- 2014 Oregon Plumbing Specialty Code (OPSC)
- 2014 Oregon Fire Code
- National Fire Protection Association (NFPA) 820, Standard for Fire Protection in Wastewater Treatment and Collection Facilities, 2016 Edition
- ANSI Standard Z358.1, Emergency Eyewash and Shower Equipment
- Oregon Administrative Rules (OAR)
- Gresham Revised Codes

3. Design Criteria

3.1 Design Criteria - Heating, Ventilation, and Air Conditioning

3.1.1 Outdoor Temperatures

The project will be located in Gresham, Oregon. Outdoor (ambient) design conditions are based on design values from the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) 2017 *Handbook of Fundamentals* for a climatologically similar location.

- Project Location: Gresham, Oregon

- Latitude: 45.551N
- Longitude: 122.409W
- Elevation: 29 feet
- ASHRAE Weather Data Location: Troutdale Airport, Oregon
- Sensible Cooling Design: 90.8 degrees Fahrenheit (°F) dry bulb / 67.2°F mean coincident wet bulb (0.4 percent occurrence)
- Evaporative Cooling Design: 69.7°F wet bulb with an 86.2°F mean coincident dry bulb @ ASHRAE 0.4 percent annual
- Heating Design: 25.3°F (99.6 percent occurrence)

3.1.2 Indoor Heat Cool Vent

Indoor design temperatures and ventilation vary based on the spaces, per Table 1. Where no ventilation requirement is listed, room will be vented per the mechanical code. Note: These are example areas since the project scope is not yet clearly defined.

Table 1. Indoor Design Temperatures and Ventilation

Proposed

Facility	Room/Area	Heating/Cooling Type	Heating/Cooling Temperatures	NFPA 820 Ventilation Requirement
(20) Existing Digester Control Building	L001 Stairwell, L101 Stairwell/Hallway, L201 Stairwell	Exist AHU w/ HW coil	55°F heating/ NA cooling	6 ACH, 0.1 inch wc positive pressure
	L002 Sludge Pump Room	Exist AHU w/ HW coil	55°F heating/ NA cooling	6 ACH, neutral pressure
	L102 Cogeneration Room	Self-heat/vent cooled	NA heating/ 104°F cooling	6 ACH, neutral to positive pressure w/ louver relief
	L103 Electrical Room	Self-heat/AC cooled	NA heating/ 78°F cooling	100 CFM positive pressure
	L104 Boiler and AHU Room	Exist AHU w/ HW coil	55°F heating/ NA cooling	6 ACH, neutral to positive pressure w/ louver relief
	L202 Penthouse	Exist AHU w/ HW coil	55°F heating/ NA cooling	6 ACH, neutral pressure
(40) New Digester Control Building	L001 Sludge HR & dewatering Room	MAU w/ HW coil	55°F heating/ NA cooling	6 ACH, negative pressure
	L101 Boiler Room	MAU w/ HW coil	55°F heating/ NA cooling	6 ACH, neutral to positive pressure w/ louver relief
	L102 Electrical Room	Self-heat/AC cooled	NA heating/ 78°F cooling	100 CFM positive pressure
(50) New Cogen Building	L100, L101 Vestibules Cogeneration Room	Heated and air conditioned	55°F heating/ NA cooling	0.1 inch positive pressure

Table 1. Indoor Design Temperatures and Ventilation
Proposed

Facility	Room/Area	Heating/Cooling Type	Heating/Cooling Temperatures	NFPA 820 Ventilation Requirement
	L102 Workstation Room	Heated and air conditioned	68°F heating/ 76°F cooling	NR
	L103 Cogeneration Room	Self-heat/vent cooled	NA heating/ 104°F cooling	6 ACH, neutral to positive pressure w/ louver relief
	L104 Electrical Room	Self-heat/AC cooled	NA heating/ 78°F cooling	200 CFM positive pressure
	L105 Cogeneration Room	Self-heat/vent cooled	NA heating/ 104°F cooling	6 ACH, neutral to positive pressure w/ louver relief

ACH = air changes per hour; AHU = air-handling unit; CFM = cubic feet per minute; HW = hot water; MAU = makeup air unit; NA = not applicable; NR = no requirement; w/ = with; wc = water column.

3.1.3 Additional HVAC Design Issues for the Existing Digester Control Building

The Digester Control Building was constructed in 1987 and was remodeled in 2005 and 2014. The digester gas compressors have been removed, but the cogeneration room, boiler room, electrical room, and sludge pumping functions remain. There are several openings that will not comply with NFPA 820 unless revised.

The adjacent digesters have two classified envelopes per NFPA 820: a Class 1 Div 1 envelope that extends 5 feet from any wall and 10 feet above the highest point, and a Class 1 Div 2 envelope that extends another 5 feet from the walls and another 15 feet above the highest point. Described below are building openings within these envelopes that affect the electrical classification requirements inside the Control Building. Tags are as indicated on the 1987 Architectural and HVAC plans. Requirements per 2020 NFPA 820 Table 6.2.2(a), row 16a and 16b.

- Cogeneration room louver L/L05 is 3 feet 11 inches from the digester, meaning the cogeneration room should be Class 1 Div 1 electrically.
- Main entry door D/L10 is 1 foot 11 inches from the digester, meaning the entry and hall should be Class 1 Div 1 electrically.
- On the Upper level, entry door D/L21 is 7 feet 2 inches from the digester, meaning that entry and stairwell should be at least Class 1 Div 2 electrically.
- On the roof, three exhaust fans, PRV-L05, PRV-L06, and PRV-L07, are less than 5 feet from the digesters, causing the stairwell, pump room, boiler room, electrical room to be Class 1 Div 1 electrically.
- Air intake penthouse RH-L01 is less than 5 feet from the digester. This serves AHU-L01, which serves the entire building. This causes the entire building to be Class 1 Div 1 electrically.
- Regardless of clearances from the digesters, the Control building itself must be separated from gas handling equipment, and must have 6 ACH to be declassified. It appears to have this, but alarms and signage may need to be updated.

3.1.4 Actions Needed to Declassify the Existing Digester Control Building

The following is proposed:

- Move cogeneration room louver L/L05 so it is more than 10 feet 0 inches from the digester.

- Move main entry door D/L10 so it is more than 10 feet 0 inches from the digester.
- Move the upper level entry door D/L21 so it is more than 10 feet 0 inches from the digester.
- On the roof, regarding the three exhaust fans, PRV-L05, PRV-L06, and PRV-L07, it would not be practical to extend them above the classified envelope as they would then be 30 feet or more up in the air, requiring guy wires. Better to provide new ventilation system with openings more than 10 feet from the digesters.
- Air intake penthouse RH-L01 should be relocated so it is more than 10 feet 0 inches from the digester. This serves an old air handler, which may also benefit from replacement.
- Regardless of clearances from the digesters, the Control Building itself must be separated from gas handling equipment, and must have 6 ACH to be declassified. It appears to have this, but alarms and signage may need to be updated.

Additional actions may be required depending on what the building is used for. The NFPA restrictions on building opening locations reduce flexibility. However, the upper floor, where the gas compressors used to be, is currently unused. It has substantial wall and roof space outside the envelope. The space could be used for new ventilation equipment, or other uses with new ventilation equipment taking up a small portion of the space.

3.2 Plumbing

3.2.1 Storm Drainage Systems

Primary and secondary roof drainage systems will be provided for all flat roofed areas. Interior piping will be provided to discharge above grade to splash blocks.

All horizontal storm drainage piping within structures will be sized based on a slope of 1/8 inch per foot. To facilitate maintenance, cleanouts will be installed throughout the primary and secondary storm drain systems. Cleanouts will be the same size of pipe up to 4 inches, and for larger pipe sizes, the cleanouts will be 4 inches in size. Piping materials will be cast iron soil pipe with hubless joints.

3.2.2 Sanitary Drainage Systems

General floor drainage will be provided unless containment of hazardous chemicals is required. Drains will also be provided near the overhead doors to remove any water that enters the doors. Funnel receptors will be located adjacent to equipment with equipment drains. Where practical, receptors will be located to serve multiple equipment drains.

Any areas requiring secondary containment will be provided with containment curbs or pits and will drain to a dry sump within the containment area. A portable sump pump will be used to pump washdown water from the sumps to a bell-up or hub drain.

All plumbing fixtures and floor drains located on the floor at or above grade will discharge by gravity to the plant sanitary sewer. All floor drains, bell-up (hub) drains, and plumbing fixtures connected to the sanitary drainage system will be provided with traps and vents. Where individual vents cannot be provided for each trap due to physical constraints, a combination waste and vent system will be utilized for floor drains and funnel receptor drains. All other drains shall be individually vented.

3.2.3 Water Piping Systems

Potable water from the site distribution system will be supplied to the domestic water fixtures and emergency shower/eyewash fixtures. Where water pressure exceeds 80 pounds per square inch gauge, pressure reducing stations will be provided. Water metering equipment will be provided at each building supplied with potable water.

Reduced pressure principal backflow preventers will be provided on the water supply to nonpotable water systems. Vacuum breakers will be provided on hose faucets and wall hydrants served by the potable water system when a nonpotable water system is not available. Domestic hot and cold water will be provided to plumbing fixtures as required. A water heater and blending valve will be provided in the cold water supply to the emergency shower/eyewash fixtures to permit tepid water temperatures (60 to 100°F) to be supplied to the fixtures. Emergency shower/eyewash fixtures will be located where required.

Hose faucets will be provided in unfinished areas that may require periodic washdown. Frost-proof wall hydrants will be provided at intervals around the exterior of the structures. A nonpotable water system consisting of piping downstream of a backflow preventer on the potable water system will be piped to the equipment for water needs. Pressure reduction will be provided as necessary for each equipment water feed. Hose faucets and wall hydrants with integral vacuum breakers will be provided as necessary for washdown and irrigation needs in and around the structure.

3.2.4 Natural Gas Piping System

Natural gas piping and pressure regulation will be provided at the boiler room building for engine generator operation, building heat, and domestic and process water heaters as necessary.

3.2.5 Plumbing Fixtures

Water closet will be wall-mounted flushometer valve type. Water heaters located downstream from a backflow prevention device will be protected by use of an expansion tank.

In the new restroom in the dewatering area, a water closet (toilet), urinal, and lavatory will be provided in the restrooms as necessary; a janitor's sink and domestic water heater will be provided in the janitor's closet. No kitchen sinks are anticipated to be provided. A sample sink will be provided in the small lab area near the dewatering equipment.

In areas with hazardous chemical storage and use, emergency shower/eyewash fixtures will be provided as required

3.3 Fire Protection

Hydrant protection is required for the facility; however, hydrant spacing for the new facility will be adequate using existing hydrants. No new hydrants are required. Fire sprinklers do not appear to be required at this time.

4. References

American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE). 2017. *Handbook of Fundamentals*.

2020 SW 4th Avenue, 3rd Floor
Portland, Oregon 97201
(503) 235-5000 F +1.214.638.0447
www.jacobs.com

Subject	Mechanical
Project Name	City of Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project
Jacobs Project Number	D3621900
To	Rob Chapler/City of Gresham
From	Jason Krumsick, P.E.
Reviewed by	Darren Edwards
Date	March 7, 2023

1. Introduction

This technical memorandum (TM) describes the process mechanical design concepts to be used for the Gresham Wastewater Treatment Plant (WWTP) Anaerobic Digestion and Cogeneration Expansion Project.

2. Applicable Codes, Standards, and Regulations

The mechanical design will make use of many applicable industry standards and design guidance documents for piping, valves, and process equipment. Following is a list of the more significant resources for design and specification standards:

- America Water Works Association
- American Society of Mechanical Engineers
- American National Standards Institute (ANSI)
- Hydraulic Institute (HI)

3. Design Criteria

3.1 Layouts and Access

Certain conventions will be followed to make the facilities optimally functional, operable, and maintainable. The following guidelines will be observed when developing layouts for new facilities and modifying layouts within existing facilities. Existing facilities may require some deviation from these guidelines.

3.1.1 Equipment

- Typically, one type of equipment will be chosen as the basis of design and layout will be based on this selection. Where other manufacturers' products are also suitable, the layout will be checked to ensure that the arrangement does not preclude the use of these alternatives.

- All required space for equipment removal, replacement, and maintenance will be included in the layout on the drawings.
- Equipment and panels will be mounted on equipment pads to protect them from washdown.
- The minimum clearance on all sides, around rotating equipment greater than 10 horsepower, should be 4 feet.
- At least 4 feet of clearance should be left between the outermost extremities of adjacent pieces of equipment, or between a wall and a piece of equipment.
- Clearance in front of any other equipment face or panel requiring maintenance should be 4 feet.
- Pressure vessels should be at least 2 feet from the back wall and 3 feet apart. Sufficient space should be provided in front of the vessel for the face piping plus 4 feet.
- For pumps, compressors, and other rotating equipment where parallel units are provided, the orientation of the drive and the rotation should be identical.
- Pumps used for sludge pumping should be arranged to minimize the distance and number of bends through which the liquid must be conveyed to the pump suction.
- Adequate headroom should be provided for removal of vertical mixer shafts.
- Provide ladders and hatches to access and remove equipment.
- Motorized hoists, monorails, or cranes should be provided where equipment component weights exceed 2,000 pounds and/or when frequent lifting for maintenance is necessary.
- Adequate lifting headroom should be provided for all equipment. An allowance for sling length or lifting beams between equipment lift points and crane or hoist hooks also needs to be included.
- Lifting eyes should be provided, in accordance with the standard details, above all equipment not otherwise provided with a means of being lifted.
- Washdown stations should be placed in logical areas to facilitate cleanup and pipe flushing. Provide hose valves so that the maximum length of hose required is 50 feet.
- Service air (compressed air) connections should be provided for pneumatic tools at appropriate locations throughout the facilities.

3.1.2 Piping and Valves

- Piping should be located so that it is not a tripping hazard, a headbanger, or a barrier to equipment access.
- Minimal piping should be located above blowers, compressors, or pumps to facilitate lifting.
- In general, piping should be laid out close to walls where it can be easily supported, particularly in spaces with high ceilings.
- If piping must be run close to a wall but not supported from it, at least 2 feet of clearance should be left between the outermost pipe flange and the wall.
- A manual vent valve should be located on the highest point of every pipeline to be filled with liquid or to be hydrostatically tested, to permit purging of air from the pipeline while it is being filled with water.
- A manual drain valve should be located on the lowest point of every pipeline to permit water drainage.
- Flexible connections should be provided to permit easy assembly and disassembly of piping and connections to equipment.

- When laying out piping, the placement of anchors and expansion joints should be kept in mind—these must be located on the drawings.
- Eccentric reducers that are flat on top should be provided if piping reducers are required on the suction side of pumps.
- Wall penetrations should be perpendicular to the wall.
- An effort should be made to keep valves within operator reach (below 6 feet 8 inches). For any valve over 6 feet 8 inches above the operating floor, provide a chain wheel operator.
- Swing check valves should not be placed in vertical piping runs for solids-bearing fluids.
- An easy disassembly coupling or pipe joint should be installed within four diameters of all valves.
- Thrust restraint should be provided for sleeve and other couplings that are not capable of internal thrust restraint.
- Ample space for valve and gate actuators should be allowed.
- Adequate clearances should be provided for rising stem valves and gates.
- Sufficient straight runs should be provided for flow meters and other instrumentation and control elements.

3.2 Piping

The Piping Schedule, included in the drawings, consists of a tabulated listing of piping requirements by service flow stream. The function of the Piping Schedule is to present the requirements for pipe materials, test pressure and type, and any special requirements for piping systems. The schedule refers the contractor to the specification section governing each piping system. The selection of piping materials is based on corrosion criteria, cost factors, and durability considerations.

Cement-lined ductile iron (CLDI) pipe will be used for most wastewater and sludge applications. For scum and thickened sludge applications, pipes 4 inches or greater in diameter will use glass-lined ductile iron (GLDI). While CLDI and GLDI are available for pipes 3 inches in diameter, they are not commonly stocked. CLDI and GLDI are not available in sizes smaller than 3 inches. Therefore, stainless steel, Schedule 80 chlorinated polyvinyl chloride (CPVC), or glass-lined steel pipe will be used. Below 4 inches in diameter, potable and nonpotable water piping will be stainless steel or Schedule 80 polyvinyl chloride (PVC) due to the poor corrosion experience with copper on this site. All chemical piping will be PVC or CPVC. In addition to the materials noted above, buried process water, wastewater, and sludge services may use high-density polyethylene (HDPE) piping.

Mill-type steel piping generally is indicated only for exposed services not requiring a finished lining after field welding, such as the heating water system. Exposed ductile iron and steel piping will allow grooved joints, except joints mating to valves, meters, and pump nozzles with flanged joints.

PVC and CPVC piping is planned for all chemical services and will be painted for ultraviolet protection and for aesthetic value, whether indoors or outdoors. Water piping and liquid-filled instrumentation piping 2 inches and smaller that are located outdoors will be insulated and metal-clad for freeze protection.

Hydraulic thrust loads exist wherever piping is pressurized and where flexible joints are placed in piping for stress relief or to accommodate thermal expansion. The thrust load must be supported by pipe thrust anchors or joint thrust restraints. Project details and specifications will include thrust restraints for all piping and for piping flexible joints. Flexible joints are sleeve-type couplings, flanged coupling adapters, dismantling joints, bellows-type expansion joints, and bell-and-spigot-type joints. Thrust protection for buried piping will be provided by restrained joint systems rather than thrust blocking.

3.2.1 Pipe Supports

Specifications for piping supports will be written to require the contractor to design all pipe supports for piping through 24 inches in diameter. Contract drawings will show typical support types in appropriate views, with standard detail references, for the purpose of indicating a general approach to piping support: for example, to show piping being supported from the floor rather than from rods and hangers from the overhead structure. Pipe support design criteria, materials, and component manufacturer model numbers will not be shown on standard details, but will be referenced to the specifications and as indicated in the Area Classification and Materials Selection Table in the drawings. In general, stainless steel and fiberglass-reinforced polyester resin support materials will be used for corrosive areas and chemical service exposures. Galvanized steel support components will be specified for dry exposures.

Supports for all piping and foul air duct 30 inches or larger in diameter will be shown with specific details indicated and all supports located on the drawings. Supports must be provided at changes in direction and under, or adjacent to, heavy valve bodies and meter bodies. Future maintenance operations requiring removal and replacement of piping and valves need to be considered for selection of appropriate supports and their locations.

3.3 Valves

3.3.1 Depiction and Call-outs on Drawings

Specification valve type numbers will be called out on the drawings for any manually operated valves. Actuated and self-contained valves will be called out on a valve schedule. The valve schedule will identify valve types, actuator type, control functions, flow stream, maximum flow, maximum differential pressure, fail position and required travel time. Valves in the valve schedule will have instrumentation and control (I&C) tags and will be shown on the process mechanical drawings.

3.3.2 Valve Actuators

In general, electric actuators will be selected for isolation and modulation applications unless a fail-position is required. Except for small solenoid valves, all powered valve actuators will be furnished with a manual override to allow the valve to be operated in the event of an actuator failure. The general valve actuator types to be used in this project will be based on the criteria listed in Table 1.

Table 1. Valve Actuator Types

Valve Type/Action	Actuator Type
Open/close valve without failure position requirements	Electric motor or solenoid
Modulating valve without failure position requirements	Electric motor
Open/close valves 6 inches and larger	Electric motor - 480 volt
Open/close valves under 6 inches	Electric motor – 120 volt
Small valves with failure position requirements	Spring or solenoid
Large valves with failure position requirements	Pneumatic

Self-contained automatic valves include valves that automatically adjust to flow conditions and maintain a specific flow parameter (pressure reducing, backpressure sustaining, pressure relief, and so on). In general, these valves will be individually selected and specified for each application as required.

For valves located in classified hazardous locations, electrical power actuators will be explosion-proof type (National Electrical Manufacturers Association 7). Classified locations shall be as identified in National Fire Protection Association 820 and the National Electrical Code.

3.4 Gates

If gates are required within tanks as design progresses, Type 316 stainless steel fabricated full-aperture sealing slide gates (also known as sluice gates) will be specified. It is not anticipated that slide gates such as weir gates will be required for these facilities. All gates will be designed for a maximum leakage of 0.05 gallon per minute per lineal foot of seating perimeter. All sluice gates will be mounted on E- or F-section wall thimbles.

3.4.1 Operators

In general, gates and operators normally will be the rising-stem type to permit visual determination of gate position. All gates will be provided with enclosed, geared-type bench-stand or floor-stand operators with clear stem covers.

- **Manual Operators.** Manual operators will be crank operated. Maximum manual crank effort required to operate the gate will not exceed 40 pounds.
- **Motor-operated Floor Stands.** Gates will be equipped with permanently installed electric operators where automatic operation requires their use. Otherwise, manual operators will be installed. Motorized gate operators will be equipped with side-mounted hand wheels for manual operation.

3.5 Sump and Wet Well Design

Care must be taken to prevent unacceptable sump vortexing and related pump air entrainment. Also, pump sump conditions are critical to prevent damaging pump cavitation.

Sufficient wet well volume to provide system control stability is required for all pump installations. Improper wet well sizing can result in serious control problems. The following items are relevant recommendations:

- Wet well surface area should be sized to prevent excessively rapid motion (rising or falling) where continuous level control is being considered. Under any viable loading changes, a level rate of change of less than 0.25 foot per second is recommended.
- Another rule of thumb (recommended by the Hydraulic Institute) is to design the wet well so that the usable control volume (in gallons, volume between top and bottom of the control) is at least two times the maximum station pumping capacity (in gallons per minute).
- A dynamic analysis is recommended, if the above two criteria are not followed.
- Wet well volume for constant speed pumps should be sized to prevent pump cycling (starting) more frequently than can be facilitated by the drive motor. National Electrical Manufacturers Association MG-1 identifies appropriate minimum cycle times (start to start).

For the simple single-pump application, the minimum wet well volume (between start and stop) that will preclude pump cycling more frequently than the desired minimum period may be calculated as follows:

$$V = \frac{QP}{4}$$

Where:

- V = wet well working volume (cubic feet)
 Q = pump capacity (cubic feet per minute)

P = minimum cycle time, start to start (minutes)

- The level measurement location point should be in a region of low turbulence, wave action, or vortexing, or provided with a stilling well, to avoid a widely fluctuating or unstable level signal.

3.6 Pump Selection and Hydraulic Calculations

Hydraulic calculations must be prepared for all pump applications. Hydraulic calculations will be performed using Applied Flow Technologies (AFT) Fathom software.

Conversion of pump operating performance for fluids having viscosities different from the viscosity of water must be determined by the pump manufacturer.

Selected pump operating points should be centered near the pump's best efficiency point at the design condition. A rating point selected to the right of best efficiency flow will allow higher efficiency at reduced flow and speed. Caution must be exercised in selecting pump operating points at the extremes of the pump operating curve because of possible excessive pump shaft radial loading, reduced bearing life, and possible shaft failure. Variable-speed pumps should be selected such that the rated flow point on the performance curve is to the right of best efficiency flow if possible. This pump selection will result in a greater turndown ratio on variable speed and more efficient operation at reduced flow. No pump should be selected to operate at less than one-third of best efficiency flow on any speed performance curve.

Care must be taken in providing adequate overlap of pump performance when multiple parallel pump installations are provided. Proper pump sequencing requires that pumps have sufficient performance overlap to allow smooth transition by adding or dropping pumps in operation.

Clean water and thin sludge applications will use centrifugal pumps. Digester mixing pumps will be chopper pumps. Thicker sludge and polymer applications will use screw centrifugal or progressing cavity pumps.

3.6.1 Net Positive Suction Head

Net positive suction head available (NPSHA) is the system energy available to drive flow into the pump suction at the impeller eye. The equation used to calculate NPSHA is shown below. Specific design characteristics determine the net positive suction head required (NPSHR) by a given manufacturer's pump. NPSHA must exceed the NPSHR of the pump(s) under consideration. NPSHA is calculated as follows:

$$NPSHA = H_b \pm H_s - H_{sf} - H_{vp}$$

Where:

H_b = barometric absolute pressure at the liquid surface, feet

$-H_s$ = suction lift, feet

$+H_s$ = suction head, feet

H_{sf} = suction piping friction losses, feet (compute in accordance with Hydraulics Application Guidelines)

H_{vp} = vapor pressure of liquid being pumped, feet

Vapor pressure is usually insignificant except when pumping warm or hot water. Keep suction lines short and straight. Check the NPSHR of several pump manufacturers. The design engineer must provide adequate NPSHA plus a margin of safety because most pump manufacturer's NPSHR curves are based on the pump operation at 3 percent deterioration in head when operating on clean, clear water at the NPSHR value. This is the basis of pump testing for NPSHR in HI standards.

NPSH calculations for centrifugal and vertical pumps must comply with ANSI and HI requirements (ANSI/HI 9.6.1, *American National Standard for Centrifugal and Vertical Pumps for NPSH Margin*).

The standard provides calculation methods and safety factors. The minimum safety factor for positive displacement pumps is 30 percent (that is, $NPSHA/NPHSR = 1.3$).

3.7 Pump Seals

Pump seals will generally be specified as single mechanical type, or double mechanical type where seal water cannot be tolerated in the process stream. For clean water services, mechanical seals without flushing water will be specified. Seal water pressure will be approximately 3 to 5 pounds per square inch gauge higher than the seal box pressure. The pump manufacturer should be consulted for seal box pressure. For a rough approximation of seal box pressure, a minimum of one-half the pump differential pressure plus the pump suction pressure should be used. Standard details will be provided for both single and double mechanical seal water supply plumbing to a pump. Packing may be used for pumps in polymer service.

3.8 Equipment Hoisting and Conveying

All process equipment must be accessible, and practical means of lifting heavy components must be thought out as part of facility layout and coordination. Often, a portable gantry crane can be set up over pumps and drives for maintenance lifting. Load-rated lifting eyes can also be installed in new concrete structures if it is known where to locate them. Adequate lifting headroom must be provided for all equipment. An allowance for sling length or lifting beams between equipment lift points and crane or hoist hook also needs to be included. Monorails or a bridge crane will be used for the cogeneration engines.

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Subject	Site Civil and Yard Piping
Project Name	City of Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project
Jacobs Project Number	D3621900
To	Rob Chapler/City of Gresham
From	Ben Kosmatka
Reviewed by	Matthew Little, P.E.
Date	March 7, 2023

1. Introduction

The purpose of this memorandum is to present the basis of design for civil site work for the City of Gresham Wastewater Treatment Plant (WWTP) Anaerobic Digestion and Cogeneration Expansion Project. The civil elements include layout of facilities, site grading access, drainage erosion control and yard piping. The civil site work shall be designed using best practices reflective of the service area and compliant with all applicable contract standards. The design philosophy, standards, and criteria presented in this memorandum will be used to help guide the designers in their decisions and judgment through the course of the project.

2. Applicable Codes, Standards, and Regulations

- American Association of State Highway and Transportation Officials (AASHTO), Policy on the Geometric Design of Highways and Streets.
- Americans with Disabilities Act (ADA), Standards for Accessible Design 2010
- American Society for Testing and Materials (ASTM)
- City of Gresham, Public Works Standards 2019
- City of Gresham, Stormwater Management Manual, 2019
- National Fire Protection Association (NFPA)
- Oregon Fire Code (2022), Fire Code Application Guide, as adopted by Gresham Fire & Emergency Services.
- U.S. Department of Transportation Federal Highway Administration (FHWA), Manual on Uniform Traffic Control Devices (MUTCD), 2009 edition, Revision 3
- Oregon Department of Transportation (ODOT) Standard Specifications for Construction 2021

3. Project Site Description

The City of Gresham, Oregon, WWTP is located between Interstate 84 and the Columbia River about 12 miles east of downtown Portland. The Union Pacific Railroad is to the north of the treatment plant running

east to west. Rolling Hills mobile home and RV Park is to the east and an industrial warehouse facility to the west. Main access to the WWTP is from the south with access off of Sandy Boulevard. It was originally built in 1954 and major improvements were made in 1970, 1979, 1987, and 2001. The overall site is shown in Figure 1.



Aerial image © 2022 Google Earth

Figure 1. Gresham WWTP Existing Site

4. Existing Solids Facilities

The WWTP consists of the upper(southern portion) and lower(northern portion) plants and the plant is permitted for 15 million gallons per day annual average flow. Waste activated sludge (WAS) from the lower plant is combined with WAS and primary sludge from the upper plant and co-thickened. Lower plant primary sludge, primary scum, and upper plant primary scum are sent directly to digestion. Thickened sludge is pumped to primary and secondary mesophilic anaerobic digestion. The digested biosolids are pumped to the Solids Building for dewatering via belt filter presses. Dewatered sludge is hauled by truck offsite for land application.

5. New Facilities

The anaerobic digestion and cogeneration expansion generally is to include a new gas storage facility, anaerobic digester, waste gas burner, Digester Control Building, cogeneration facility, gas treatment facility, reclaimed natural gas storage, "food waste slurry" (FWS) receiving station and update to the biosolids storage facility.

Site civil work will include incorporation of topographical survey, site layout, grading, landscape, and access. Site electrical work is described in the Electrical Discipline Technical Memorandum. Site utilities will be developed in a further stage of design not in the scope of this phase. A site plan will be developed for this stage of design.

6. Roadwork Design

An asphalt driveway is planned to extend from existing roadway to the digester control building to match existing roadway. Another portion of driveway is to extend to an unloading pad to the north of the new

biosolids storage facility. The design vehicle used for this layout is an SU-30 truck. The standard road width for the driveway that extends to the new unloading pad is to match the original driveway extending to the solids storage facility of 24 feet. Where pavement is being replaced, during final design a verification of a pavement section is to be included.

7. Topographic Survey

A topographic survey scope is to be conducted and will be incorporated for this project. The survey should include the western half of the plant from north of the biosolids storage facility to Secondary Clarifier 4.

7.1 Horizontal and Vertical Control

The project coordinate system will be based on the following data:

Horizontal:

Datum: North American Datum 1983 (adjustment 2011)

Zone: Oregon State Plane, North Zone

Linear Units: International Foot

Vertical:

Datum: National Geodetic Vertical Datum of 1929 (NGVD 29)

8. Base Mapping

New topographical survey will be obtained for the area of work as described in the above Topographical Survey section. This information will be combined with overall site plan base mapping from record drawings and computer-aided drafting files provided by the City of Gresham.

An existing yard piping base map was provided by the City from their record drawings and CAD files. This predesign effort has identified two existing lines (a 30-inch-diameter PE line and an 8-inch-diameter WAS line) that will need to be relocated to accommodate the proposed design. A secondary effluent line to the Secondary Clarifier 4 will be protected and not in conflict with the design.

Potholing site investigations will be required during detailed design to confirm location and depth of the existing pipelines that the new design will either connect to or cross (either over or under). The yard piping design will need to be developed further before the scope of this potholing exercise can be confirmed. This activity should occur as soon as possible during the detailed design effort in order to allow the design team to respond to any unexpected conditions that are discovered.

9. Grading

Grading plans will show finish grade elevations of all new site work. Drainage arrows will be used to indicate direction of stormwater sheet flow, and slope arrows will be used to show gradient rates for slopes. Site will be graded to slope away from facilities at minimum 5 percent for the first 10 feet. Minimum cross slopes of 2 percent and minimum longitudinal slope of 0.5 percent will be applied to all roads. New roads will match existing grades at the project limits. Finish grade contours will be shown with 1-foot contour intervals, with control points and break lines indicated. Spot grades at grade changes and flowlines will be shown. Maximum cut and fill slopes for permanent grading will be 3:1.

10. Erosion Control

During construction, erosion control measures will be implemented in accordance with Oregon Department of Environmental Quality (DEQ) to prevent adverse environmental degradation that would affect adjacent owners. The erosion control measures will be tailored to the site to prevent sediment-laden water from leaving the site and will be appropriate during each phase of construction. Application for the

1200-CN permit will be through the City of Gresham with the disturbance being under 5 acres. The following erosion control measures will be used onsite:

- Site development considerations with construction scheduling
- Maintenance of buffer zones
- Dust control on disturbed areas and access roads
- Silt fence at limits of clearing
- Check dams to control velocity along ditches and long longitudinal grades
- Stabilization of construction entrance to all paved surfaces
- Catch basin/inlet protection
- Materials management with material delivery, storage, and waste management
- Vehicle and equipment management with construction practices, cleaning, fueling and maintenance
- Covered and maintained stockpile storage
- Management of dewatering flows

An onsite erosion control lead will monitor the condition of all installed erosion control measures on a regular basis and will adjust the approved erosion control plan to correct issues as they arise. All erosion control measures will be shown and implemented in accordance with the Oregon Department of Environmental Quality (DEQ).

11. Site Drainage

Site grading will provide adequate drainage away from facilities and transversable grades for vehicles. The City of Gresham stormwater management manual will be used to design any of stormwater drainage on the project site. Stormwater will be routed by surface flow to the nearest existing stormwater facility.

12. Site Security

The existing WWTP perimeter is secured with chain link fence. Where required to be removed for new facilities or roads, fencing will be replaced in kind. If required, manual gates will also be replaced. No automatic gates are included in this project.

13. Yard Piping

There are yard piping challenges that will be addressed with the new cogeneration facility layout and an aerial pipe bridge/rack is a design alternative. Remediation of the condensation in the gas line for a below grade pipe was the design criteria that brought about the design alternative to support the pipe aerial in a bridge/rack. The anticipated yard piping for the project will generally include:

- Heating water supply
- Heating water return
- Digester gas
- Natural gas
- Two 6-inch thickened sludge glass lined ductile iron (GLDI) pipe
- 6-inch primary sludge GLDI pipe
- 4-inch FOG GLDI pipe

- 4-inch or 6-inch EBS GLDI pipe
- Overflow(OF) from the new digester
- Potable water
- Non-potable
- Secondary effluent
- Mixed liquor
- Digested sludge
- 8-inch WAS
- Storm drainage

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Subject	Structural
Project Name	City of Gresham WWTP Anaerobic Digestion and Cogeneration Expansion Project
Jacobs Project Number	D3621900
To	Rob Chapler/City of Gresham
From	Michele McHenry, P.E., S.E.
Reviewed by	Rich Forrest, P.E., S.E.
Date	March 7, 2023

1. Introduction

The purpose of this section is to establish structural design criteria that will provide a uniform, efficient, and effective approach to the structural design for the Anaerobic Digestion and Cogeneration Expansion Project at the City of Gresham Wastewater Treatment Plant (WWTP). All new structures and modifications to existing structures will be designed to provide high performance, energy efficient, and low maintenance facilities. The design criteria presented in this memorandum will be the basis for the structural design of all the facilities included in the project.

2. Applicable Codes, Standards, and Regulations

The following codes, standards, regulations, and references will be considered as part of the design development. The latest edition of each code will be used unless a specific year is listed.

2.1 General

- 2022 Oregon Structural Specialty Code based on the 2021 International Building Code and City of Gresham amendments.
- American Society of Civil Engineers/Structural Engineering Institute (ASCE/SEI) 7-16, Minimum Design Loads for Buildings and Other Structures.
- ASCE/SEI 41-17, Seismic Evaluation and Retrofit of Existing Buildings.
- American Petroleum Institute (API) RP 686-2009, Recommended Practice for Machinery Installation and Installation Design.

2.2 Reinforced Concrete

- American Concrete Institute (ACI) 318-19, Building Code Requirements for Reinforced Concrete.
- ACI 350-20, Code Requirements for Environmental Engineering Concrete Structures.
- ACI 350.1-10, Specification for Tightness Testing of Environmental Engineering Concrete Containment Structures.

- ACI 350.3-20, Code Requirements for Seismic Analysis and Design of Liquid-Containing Concrete Structures.

2.3 Masonry

- The Masonry Society (TMS) 402-16, Building Code Requirements for Masonry Structures.
- TMS 602-16, Specification for Masonry Structures.

2.4 Steel

- American Institute of Steel Construction (AISC) 15th Edition *Steel Construction Manual*, including:
 - ANSI/AISC 360-16, Specification for Structural Steel Buildings.
 - Research Council on Structural Connections (RCSC) 2014 Specification for Structural Joints Using High-Strength Bolts.
- AISC 3rd Edition *Seismic Design Manual*, including:
 - ANSI/AISC 341-16, Seismic Provisions for Structural Steel Buildings.
- American Iron and Steel Institute (AISI) S100-20, North American Specification for the Design of Cold-Formed Steel Structural Members.
- AISI S240-20, North American Standard for Cold-Formed Steel Structural Framing.
- AISI S400-20, North American Standard for Seismic Design of Cold-Formed Steel Structural Systems.
- Steel Deck Institute (SDI) RD-2017, Standard for Steel Roof Deck.
- SDI QA/QC-2017, Standard for Quality Control and Quality Assurance for Installation of Steel Deck.

2.5 Stainless Steel

- ANSI/AISC 370-21, Specification for Structural Stainless Steel Buildings.
- AISC 313-21, Code of Standard Practice for Structural Stainless Steel Buildings.
- ASCE/SEI 8-02, Specification for the Design of Cold-Formed Stainless Steel Structural Members.

2.6 Aluminum

- Aluminum Association (AA) ADM-20, *Aluminum Design Manual*.

2.7 Welding

- American Welding Society (AWS) D1.1/D1.1M:2020, *Structural Welding Code – Steel*.
- AWS D1.2/D1.2M:2014, *Structural Welding Code – Aluminum*.
- AWS D1.3/D1.3M:2018, *Structural Welding Code – Sheet Steel*.
- AWS D1.4/D1.4M:2018, *Structural Welding Code – Steel Reinforcing Bars*.
- AWS D1.6/D1.6M:2017, *Structural Welding Code – Stainless Steel*.

2.8 Wood

- American Wood Council (AWC) NDS-2018, National Design Specification (NDS) for Wood Construction.
- AWC SDPWS-2021, Special Design Provisions for Wind and Seismic.

- APA - Engineered Wood Association (APA) ANSI 117-2020, Standard Specification for Structural Glued Laminated Timber of Softwood Species.
- ANSI/APA 190.1-2017, Structural Glued Laminated Timber.
- APA S475-20, Glued Laminated Beam Design Tables.
- APA S560-20, Field Notching and Drilling of Glued Laminated Timber Beams.
- APA T300-16, Glulam Connection Details.

2.9 Metal Fabrications

- National Association of Architectural Metal Manufacturers (NAAMM) MBG 531-17, *Metal Bar Grating Manual*.
- NAAMM MBG 532-19, *Heavy Duty Metal Bar Grating Manual*.
- ANSI-ASC A14.3-2018, *American National Standard for Ladders – Fixed – Safety Requirements*.

3. Design Criteria

3.1 General

In accordance with Oregon Structural Specialty Code (OSSC) Table 1604.5, wastewater treatment plants are classified as Risk Category III.

3.2 Dead Loads

The loads resulting from the weight of all fixed construction, equipment, fixtures, etc., such as walls, floors, roofs, equipment bases, and all permanent non-removable stationary construction, are considered to be dead loads. Numerical values used for these loads may be determined by either actual known weights of the respective items, or by documentation presented in the OSSC or other publications.

3.3 Live Loads

People Only Areas:

Corridors, Exits, and Stairs: 100 pounds per square foot (psf)
Access Only Platforms and Walkways: 60 psf

Process Areas: 200 psf

Electrical Areas: 300 psf

Light Storage Areas: 125 psf

Heavy Storage Areas: 250 psf

Roof Surfaces with Maintenance Access: 300 pounds concentrated load

Vehicle Access Areas: HL-93 AASHTO (American Association of State Highway and Transportation Officials)

3.4 Roof Live Load

Minimum roof live load shall be 20 psf. Loads will be increase where required assuming primary roof drains are plugged and water is at the overflow elevation.

3.5 Roof Collateral Load

The roof collateral load shall be 10 psf plus operating weight from any roof-mounted equipment. In process buildings, use a collateral load of 25 psf, unless there is a crane bay beneath the structure that would prohibit large amounts of process piping from being attached to roof members.

3.6 Snow Load

The ground snow load in accordance with OSSC Section 1608.2.2 is 11 psf, with 4 psf additional for every 100 feet in elevation gain above the modeled elevation of 200 feet. As elevations at the site do not exceed the modeled elevation, the ground snow load is set at 11 psf.

Exposure: Partially Exposed

Exposure Factor (C_e): 1.0

Thermal Factor (C_t): 1.0

Importance Factor (I_s): 1.1

Minimum Flat Roof Snow Load (p_m): $20I_s = 22$ psf

Rain-on-Snow Surcharge Load: 5 psf

Frost depth is set at 18 inches per the City of Gresham standards.

3.7 Seismic Design Criteria

ASCE 7 Mapped Spectral Acceleration Values for the site at latitude 45.546841, longitude -122.458648:

5% damped at short periods: $S_S = 0.882$ g

5% damped at 1 second period: $S_1 = 0.371$ g

ASCE 7 Mapped Peak Ground Acceleration: $PGA = 0.401$ g

Site Classification: D (default)

Short-Period Site Coefficient (F_a): 1.2

Long-Period Site Coefficient (F_v): null*

Site Coefficient for Peak Ground Acceleration (F_{PGA}): 1.2

Long-Period Transition Period (T_L): 16 seconds

Importance Factor (I_e): 1.25

Seismic Design Category: D

*Project structural design utilizes Exception 2 of ASCE 7 Section 11.4.8, with a site coefficient of $F_v=1.93$ per Table 11.4-2.

3.7.1 Effective Seismic Weight

Effective seismic weight shall consist of structure self-weight, known equipment operating weights, and other dead loads. For process areas, electrical rooms, and storage areas, the effective seismic weight shall also include 25 percent of the live load.

3.7.2 Seismic Performance Objectives

A seismic resilience plan was developed by Carollo Engineers in 2019 to evaluate the City of Gresham's wastewater system. The plan established two criteria for seismic design of new structures and also evaluated existing facilities against two different levels of seismic event. The two different events identified for evaluation and the performance objectives are as follows:

1. A magnitude 9.0 Cascadia-Subduction Zone (CSZ) earthquake. It was determined that the performance level for this seismic event should be to have structures designed for Immediate Occupancy, i.e., facility is safe to occupy after event, but some repairs may be required for continued operation of facilities.
2. Maximum Considered Earthquake (MCE) from American Society of Civil Engineers' (ASCE) code prescribed event. It was determined that the performance level for this seismic event should be to have structures designed for Life Safety, i.e., facility will retain some strength against collapse and should prevent loss of life, but may be damaged beyond repair.

Although the CSZ is a much larger seismic event, the epicenter is much further away from the site than the faults that would cause the MCE seismic event. Consequently, the ground accelerations experienced at the site from the CSZ event are roughly 40 percent of what would be expected from the MCE event. This results in a requirement to design the new facilities to resist the larger accelerations from the MCE (approximately the code requirement for Risk Category IV structures) and then check the structure and equipment for performance objectives against the smaller accelerations from the CSZ event. For this project, new and modified existing facilities will be designed to the Risk Category III building code criteria (approximately 83 percent of the MCE) and will be checked for the CSZ.

The resiliency plan also included a resiliency assessment of the existing facilities. The existing digesters and digester control building were identified as having structural and nonstructural seismic deficiencies. These deficiencies will need to be investigated in more detail and evaluated to determine if the City would like the design consultant to include these voluntary seismic upgrades as part of the solids facility improvements, or if these upgrades would be implemented under a separate capital project.

3.8 Wind Design Criteria

Basic Design Wind Speed (V , 3-second gust): 105 miles per hour (mph)

Allowable Stress Design Wind Speed (V_{asd}): 81 mph

Exposure Category: C

3.9 Fluid Loads

Refer to drawings for design liquid levels and top of base slab elevations. The design of the containment structures will include a check of cracking under normal loads. Sloshing loads during a seismic event will also be taken into account during the design. Only the available capacity of the member will be checked for seismic loads.

Basins will be designed for maximum fluid levels at overflow considering there will be no support from backfill where placed against the basin walls. Maximum loads from any combination of full or empty tank cells will be applied.

4. Material Standards

4.1 Reinforced Concrete

The materials recommended for the concrete on this project are as follows:

- Typical cast-in-place concrete including sidewalks and curbs shall have a minimum compressive strength of 4,000 pounds per square inch (psi) at 28 days (4,500 psi at 56 days for code-required freeze-thaw protection). Secondary elements such as pipe encasements, conduit encasements, and concrete fill shall have a minimum compressive strength of 4,000 psi at 28 days.
- Reinforcing steel shall conform to American Society for Testing and Materials (ASTM) A615, Grade 60. Reinforcing to be welded shall conform to ASTM A706.

4.2 Concrete Masonry Units

The materials recommended for the concrete masonry units on this project are as follows:

- All masonry will conform to ASTM C90, medium weight with a minimum compressive strength of 2,000 psi.
- All masonry assemblies will have a minimum compressive strength of 2,000 psi.
- Grout will conform to ASTM C476 coarse grout with a minimum 28-day compressive strength of 2,000 psi.
- Mortar will conform to ASTM C270, Type S.

4.3 Structural Steel

Table 1 summarizes the structural steel materials recommended for the project.

Table 1. Structural Steel Materials

Member Type	ASTM Reference	Yield Strength, Fy (ksi)
Steel W-shapes	A992	50
Other rolled members, plates and rods	A36	36
Steel pipe	A53, Type E or S, Grade B	35
Steel tubes	A500 Grade C	46 (round) 50 (rectangular)
Steel deck	A653, A1008, or A1063	40 (minimum)
Bolts for framing connections	F3125 Grade A325	-
Anchor Bolts, Wet Areas	A193, Type 316 Stainless Steel	-
Anchor Bolts, Dry Areas	A193, Type 304 or 316 Stainless Steel	-

ksi = thousand pounds per square inch.

4.4 Timber and Wood Construction

Beams, stringers, posts, and timbers will utilize Douglas Fir-Larch Select Structural. Planks will utilize Douglas Fir-Larch No. 1 or better. Other wood members including sills, blocking, and furring will utilize Douglas Fir-Larch No. 2. Glued laminated timber beams will be Douglas Fir-Larch or Hem-Fir grades specified with minimum allowable working stress values for loads of normal duration of 2,000 psi in bending, 1,400 psi in tension, and 1,700 psi in compression parallel to grain and a minimum modulus of elasticity (E) of 1,700,000 psi for dry conditions of use.

5. Special Inspection, Structural Observation, and Quality Assurance Plan

Owner-furnished Special Inspection will be required in accordance with Chapter 17 of the OSSC. Section 1704.3 requires the design professional in responsible charge to prepare a Statement of Special Inspections. This statement will incorporate the inspection requirements of Section 1704 for the following portions of the work:

- Concrete construction including reinforcing steel, anchors, and embeds

- Masonry construction including reinforcing steel, anchors, and embeds
- Structural steel
- Cold-formed steel deck
- High-strength bolts
- Structural welding
- Seismic force-resisting systems including structural wood fastening
- Mechanical and electrical components
- Grading, excavation, and filling

The Owner will employ a registered design professional to perform the Structural Observation in accordance with Section 1704.6 of the OSSC. The Structural Observation will include visual observation at significant construction stages and at the completion of structural systems. The design professional will provide a written statement to the building official following each visit, and at the conclusion of construction, acknowledging that all required site visits have been made and identifying any deficiencies that have not been resolved.

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HURST

BOILER & WELDING CO., INC.

AVAILABLE WITH LOW NOX

HURST SERIES EURO

3-PASS SCOTCH MARINE DESIGN
Low Profile, Wet Back Construction

HIGH PRESSURE BOILER

Capacities from 100 to 2000 BHP.
3348 to 66950 MBTU/HR.

STEAM

Pressures to 15-300 PSI.

HOT WATER

Section I and Section IV



**SKID MOUNTED
MODULAR PACKAGED**

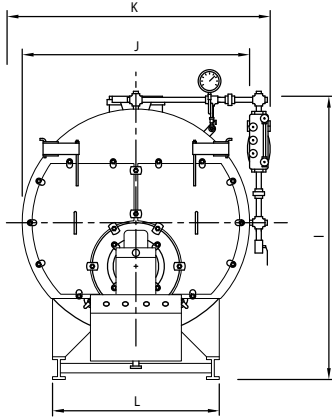
*"Large combustion chamber with
low heat release for complete combustion."*

HURST PERFORMANCE SERIES BOILERS

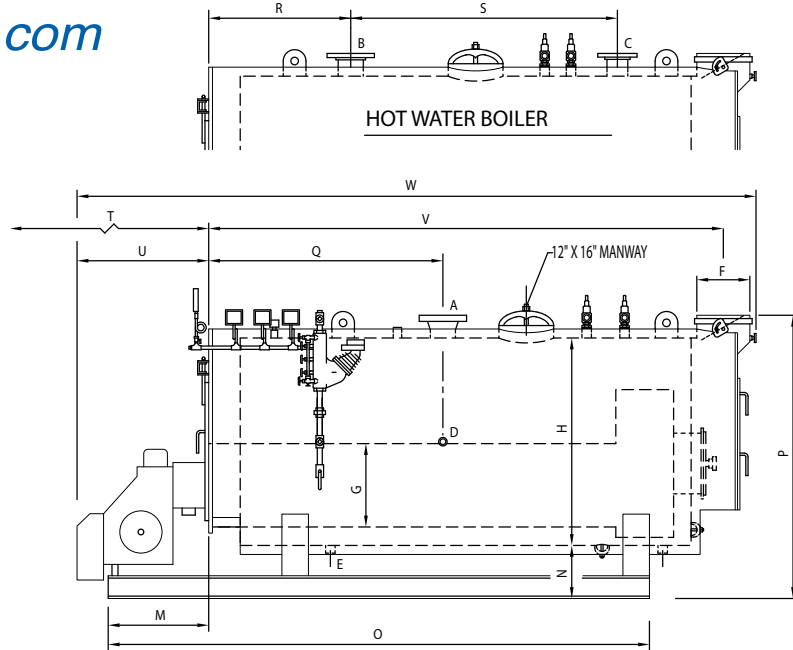
SERIES EURO



NOTE: THE 400 HP SIZE
HAS A REMOVABLE STACK
SECT'N. FOR SHIPPING
CONSULT FACTORY



FRONT VIEW



SIDE VIEW

BOILER SPECIFICATIONS

BOILER HORSEPOWER

			100	125	150	200	250	300	350	400
STEAM OUTPUT	FROM & @ 212°	LBS/HR	3450	4313	5175	6900	8625	10350	12075	13800
GROSS OUTPUT	@ 33,475 BTU/BHP	MBH	3348	4184	5021	6695	8369	10043	11716	13390
FIRING RATE GAS	1,000 BTU	CFH	4200	5250	6300	8400	10500	12600	14700	16800
FIRING RATE LP GAS	91,500 BTU	GPH	46	57	69	92	115	138	160	184
FIRING RATE OIL #2	140,000 BTU	GPH	29.9	37.4	45	60	75	90	105	120
FIRING RATE OIL #5 & #6	150,000 BTU	GPH	28	35	42	56	70	84	98	112

A	NOTE: 1 STEAM OUTLET SIZE	150 PSI	IN	4	4	4	4	6	6	6	A
A	NOTE: 2 STEAM OUTLET SIZE	15 PSI	IN	8	8	8	8	10	10	10	A
B	NOTE: 2 WATER SUPPLY SIZE	30 PSI	IN	8	8	8	8	10	10	10	B
C	NOTE: 2 WATER RETURN SIZE	30 PSI	IN	6	6	6	6	8	8	8	C
D	FEEDWATER CONNECTION		IN	1 1/4	1 1/4	1 1/4	1 1/2	1 1/2	2	2	D
E	BLOWDOWN CONNECTION (BTM)	HIGH PRESS.	IN	1 1/4	1 1/4	1 1/4	1 1/4	1 1/2	1 1/2	1 1/2	E
E	BLOWDOWN CONNECTION (BTM)	LOW PRESS. & HW	IN	1 1/2	1 1/2	2	2	2	2	2	E
F	STACK OUTLET SIZE O.D.		IN	14	14	16	16	18	20	20	F
G	FURNACE O.D.		IN	30	30	35 1/4	35 1/4	38	38	38	G
H	SHELL I.D.		IN	54	54	66	66	72	75 1/2	75 1/2	H
I	NOTE: 3 SUPPLY HEIGHT	150 PSI	IN	74 5/8	74 5/8	87 3/4	87 3/4	93 3/4	97 1/2	97 1/2	I
J	WIDTH WITHOUT TRIM		IN	60	60	73	73	78	83	83	J
K	WIDTH WITH TRIM		IN	67	67	80	80	87	89	89	K
L	SKID WIDTH		IN	44	44	51	51	57	60	60	L
M	END OF SKID FROM FRT. PLATE		IN	19 11/16	21 11/16	22 11/16	22 11/16	28 5/8	31 5/8	31 5/8	M
N	SHELL TO FLOOR		IN	14	14	15	15	15	15	14	N
O	SKID LENGTH		IN	120	134	159	165	180	200	206	O
P	STACK HEIGHT		IN	74 5/8	74 5/8	87 3/4	87 3/4	93 3/4	97 1/2	97 1/2	P
Q	STEAM OUTLET LOCATION	15 & 150 PSI	IN	55 13/16	55 13/16	63 13/16	63 13/16	67 7/8	82 7/8	82 7/8	Q
R	SUPPLY LOCATION		IN	35 13/16	35 13/16	39 13/16	39 13/16	45 7/8	50 7/8	50 7/8	R
S	RETURN LOCATION		IN	56	68	80	84	86	96	99	S
T	TUBE REMOVAL	FRONT	IN	111	123	144	150	161	176	182	T
U	BURNER PROJECTION	STANDARD BURNER	IN	32	35	35	35	48	52	52	U
V	STACK OUTLET		IN	119 13/16	131 13/16	153 13/16	159 13/16	171 7/8	187 7/8	195 7/8	V
W	APPROX. OVERALL LENGTH		IN	162	177	200	206	232	253	263	W
	OVERALL SHIPPING HEIGHT	30 & 150 PSI	IN	76	76	89	89	95	99	99	
	SHIPPING WEIGHT - HIGH PRESS.	150 PSI	LBS	8,300	9,000	13,500	14,650	17,250	20,500	21,000	
	WATER CAPACITY - STEAM	NWL	GALS	516	579	1025	967	1406	1538	1555	
	WATER CAPACITY - WATER	FLOODED	GALS	573	643	1222	1218	1648	1949	2022	
	BOILER HORSEPOWER			100	125	150	200	250	300	350	400

NOTE: 1 3" & ABOVE ARE 300# ANSI FLANGE.
NOTE: 2 4" & ABOVE ARE 150# ANSI FLANGE.
DIMENSIONS SUBJECT TO CHANGE WITHOUT NOTICE.

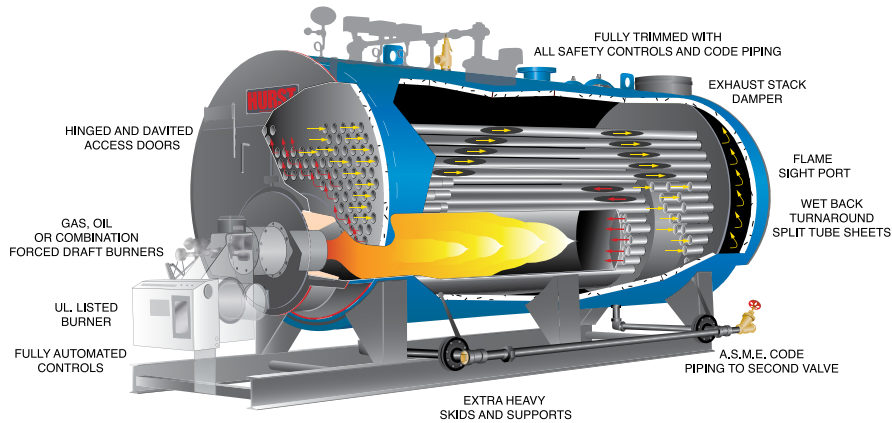
FOR SECTION-I HIGH PRESSURE STEAM - THIS CHART APPLICABLE FOR 50 PSI UP TO 300 PSI.
STEAM, AND LOW AND HIGH PRESSURE HOT WATER ONLY.
FOR STEAM PRESSURES BELOW 50 PSI. AND FOR SECTION-IV LOW PRESSURE STEAM BELOW 15 PSI.
CONSULT FACTORY FOR BOILER DIMENSIONS AND OR CERTIFIED DRAWINGS.

Inspected and
registered with the
National Board of
Boiler & Pressure
Vessel Inspectors.



Designed,
constructed and
stamped in
accordance with
the requirements
of the ASME
Boiler Codes.

CUT AWAY VIEW



THREE PASS FIRETUBE DESIGN

100-2000 BHP

Wetback Construction

Eliminates Refractory Rear Door & Baffles Between Flue Gas Passes

	500	600	700	750	800	900	1000	1200	1500	1800	2000
	17250	20700	24150	25875	27600	31050	34500	41400	51750	62100	69000
	16738	20085	23432	25106	26780	30128	33475	40170	50213	60255	66950
	21000	25200	29400	31500	33600	37800	42000	50400	63000	75600	84000
	230	275	320	344	368	413	460	550	688	826	918
	150	180	210	225	240	270	300	360	450	540	600
	140	168	196	210	224	252	280	336	420	504	560
A	6	8	8	8	8	8	8	10	10	*12	*12
A	10	12	12	12	12	14	14	14	14	*16	*16
B	10	12	12	12	12	12	12	14	14	*16	*16
C	8	8	10	10	10	12	12	14	14	*16	*16
D	2	2 1/2	2 1/2	2 1/2	2 1/2	2 1/2	2 1/2	2 1/2	2 1/2	2 1/2	2 1/2
E	1 1/2	1 1/2	2	2	2	2	2	2	2	2	2
E	2	2	2	2	2	2	2	2	2 1/2	2 1/2	2 1/2
F	24	28	34	34	34	34	34	38	42	*48	*48
G	50	54	56	56	60	60	60	60	62	66	66
H	96	102	108	108	112	112	112	126	136	142	142
I	121	127	133	133	137 1/4	137 1/4	137 1/4	152 1/4	162 1/2	162	162
J	102 3/4	108	115	115	119	119	119	133 1/2	144 1/2	149	149
K	108 1/4	113 1/4	124	124	136	136	136	139 1/2	150 3/4	161	161
L	76	78	86	86	92	92	92	108	114	124	124
M	31 5/8	52 5/8	46 5/8	46 5/8	36 5/8	52 1/2	51 1/2	55 5/8	59 5/8	70	76
N	18	18	18	18	18	18	18	18	18	16	16
O	212	240	228	228	228	264	288	294	320	336	354
P	122	128	134	134	138 1/4	138 1/4	138 1/4	152 1/4	162 1/2	162	162
Q	96 7/8	96 3/8	89 7/8	90 1/2	101 3/8	122	116	122 3/8	135 7/8	134	140
R	60 3/8	66 3/8	60 7/8	60 7/8	63	68	75	75	74	74	74
S	162 3/8	168 3/8	162 7/8	162 7/8	165	188	206	206	218	218	230
T	195	202	196	196	209	231	253	281	281	281	293
U	65	66	66	70	70	75	75	84	84	96	96
V	208 7/8	217 7/8	214 3/8	214 3/8	225 7/8	249 1/2	271 1/2	273 1/2	302 7/8	307	319
W	279	290	299 3/8	303 3/8	312	343 1/2	365 1/2	379	405	429	441
	122	128	134	138 1/4	138 1/4	138 1/4	138 1/4	152 1/4	162 1/2	164	164
	35,000	38,000	43,000	44,200	49,500	53,750	57,500	72,000	89,000	*89,000	*92,000
	2390	2688	3405	3348	3590	4015	4443	5855	7176	5855	7165
	3453	3983	4290	4233	4823	5152	5697	7980	10,386	7980	10,532
	500	600	700	750	800	900	1000	1200	1500	1800	2000

* NOTE: 1800 & 2000 HP WEIGHTS DO NOT INCLUDE BURNER OR REFRACTORY HEAD RING.

* NOTE: STUDDER OUTLET FLG'S ON 400 HP, 1800-2000 HP.

BOILER DESIGN: Three-Pass "Scotch Marine" Firetube design with stress relieving "Wetback" construction. Pressure designs for steam are 15-300 psi. 100-600 hp. 250 psi. max. for 700-1500 hp. and 200 psi. max. for 1800-2000 hp.

Hot Water pressures models are from 30-160 psi. High pressure, high temperature Section I hot water boilers available.

Factory assembled with trim, tested, ASME code, UL, and CSD-1 standards.

STEAM MODEL TRIM: Safety relief valve, operating pressure control, high limit pressure control with manual reset, steam pressure gauge with syphon, combination pump control and low water cut-off with gauge glass assembly and drain valve, auxiliary low water cut-off with manual reset.

HOT WATER MODEL TRIM: Safety relief valve, operating temperature control, high limit temperature control with manual reset, combination pressure & temperature gauge, low water cut-off control with manual reset.

BURNER: Matched UL listed "forced draft" power burners with factory pre-piped, wired and tested fuel configurations for natural gas, propane (LP) gas, No. 2 (diesel) oil, or combination of both gas/oil.

HURST PERFORMANCE SERIES BOILERS

STANDARD FEATURES

- Boiler is of the three-pass, scotch type, built and stamped in accordance with the requirements of the ASME Code, and listed by the National Board of Boilers and Pressure Vessel Inspectors.
- Large combustion chamber with low heat release for complete combustion.
- Smoke box is rear-mounted with slip-on stack connector.
- Access to fireside is accomplished with hinged and davited front and rear doors. Flame observation ports are located on front and rear.
- Openings for vessel cleanout and inspection of waterside are provided with 3" x 4" hand holes, and 12" x 16" manway access.
- Insulated with 2" high density mineral wool, lagged with 22 gauge grip jacketing, baked on finish to resist chipping and fading.
- Firetubes are rolled and beaded on power boilers, expanded and flared on low pressure boilers.
- Supports include lifting lugs securely welded to the top of shell; structural steel support legs on skids support the boiler so that special foundations are not required.

Stress Relieving "Wetback" Construction for Extra-Long Life

Standard Steam Trim

- Operating & high limit pressure control
- Modulating pressure control (when appl.)
- Water column with gauge glass, combination low water cut-off & pump control
- Probe Aux, L.W.C.O.
Steam pressure gauge, syphon & test cock
- Water column drain valve
- Safety relief valve(s) per ASME Code

Standard Water Trim

- Operating & high limit temperature control
- Modulating temperature control (when appl.)
- Probe type low water cut-off control
- Combination pressure & temperature gauge
- Hot water return baffle for shock resistance
- Safety relief valve(s) per ASME Code

HBC-09503
07/2014



hurstboiler.com

HURST BOILER & Welding Co., Inc.

100 Boilermaker Lane • Coolidge, GA 31738-0530
Tel: (229) 346-3545 • Fax: (229) 346-3874
email: info@hurstboiler.com

–weishaupt–

product

Information on Ultra Low NO_x gas burners



Ultra Low NO_x emissions

WM-G10 ZM-PLN and WM-G20 ZM-PLN monarch® burners (290 – 10,240 MBH)

A new class of emissions: Ultra-Low NO_x



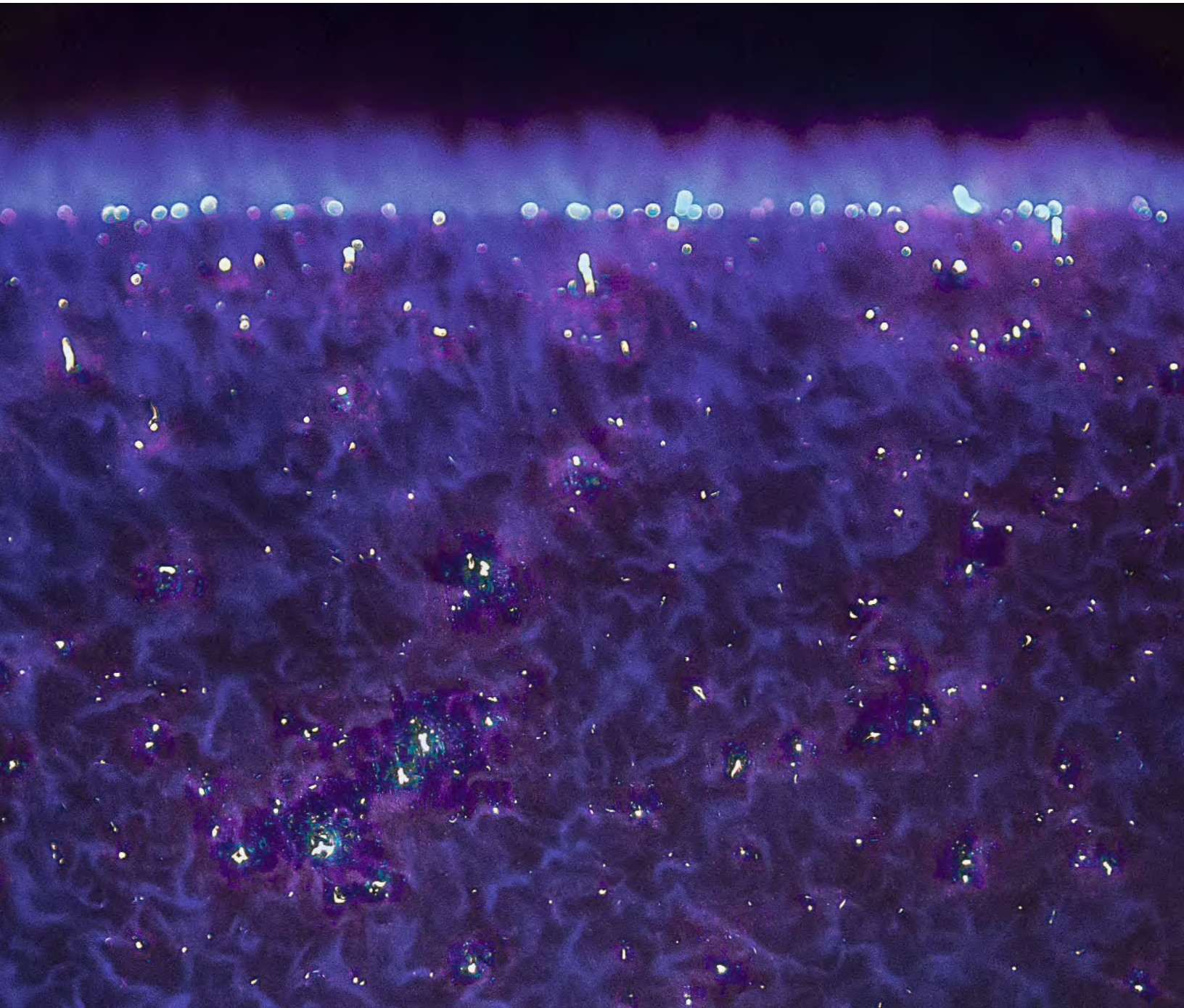
Test-firing chambers for medium and large-sized burners at the Weishaupt Research & Development Centre

For more than six decades, Weishaupt's monarch® series burners have been used on a wide variety of heat generators and industrial plant, and their success has helped establishing Weishaupt's outstanding reputation.

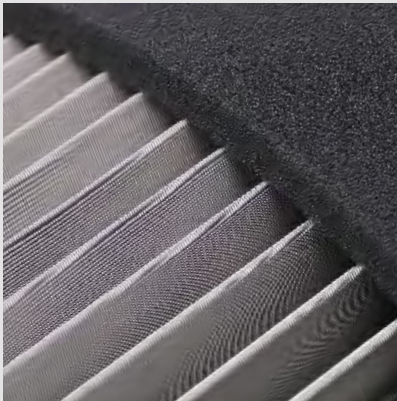
The PLN-version burners are ready for use in situations where the very lowest of emission levels are being demanded. PLN stands for Premix Low NO_x – a system that combines premixing with surface-stabilized combustion.

A further advantage of this type of combustion system is that it can be utilized on appliances with particularly small combustion chambers.

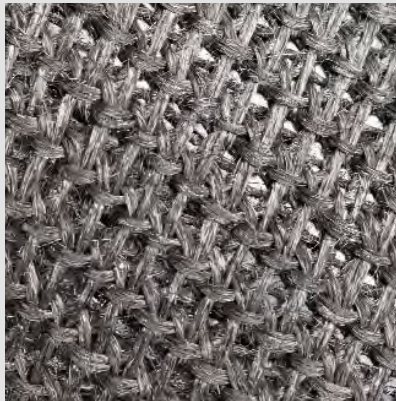
Homogeneous, surface-stabilized combustion



Weishaupt premix technology for extremely low NO_x emission



The metal gauze air filter is protected from dust by an additional foam pre-filter sleeve



A microweave mat made from a high-quality alloy permits the right amount of gas / air mix to pass



Weishaupt PLN-version burners can also be used in very small combustion chambers

Everywhere in the world, emission limits are becoming more and more stringent, with a focus on NO_x emissions in particular. Weishaupt has therefore developed a new generation of burners designed to fulfil these demands.

Weishaupt burners have always been particularly efficient and environmentally friendly. Premix burner technology is used to achieve NO_x emissions below 15 ppm and even lower.

Premixing followed by surface-stabilized combustion has been state of the art for many years in small condensing boilers. It is environmentally friendly, reliable and efficient. Extending these benefits to typical heat generators with larger outputs was the developmental goal for the PLN-version burners.

Special gas / air mix

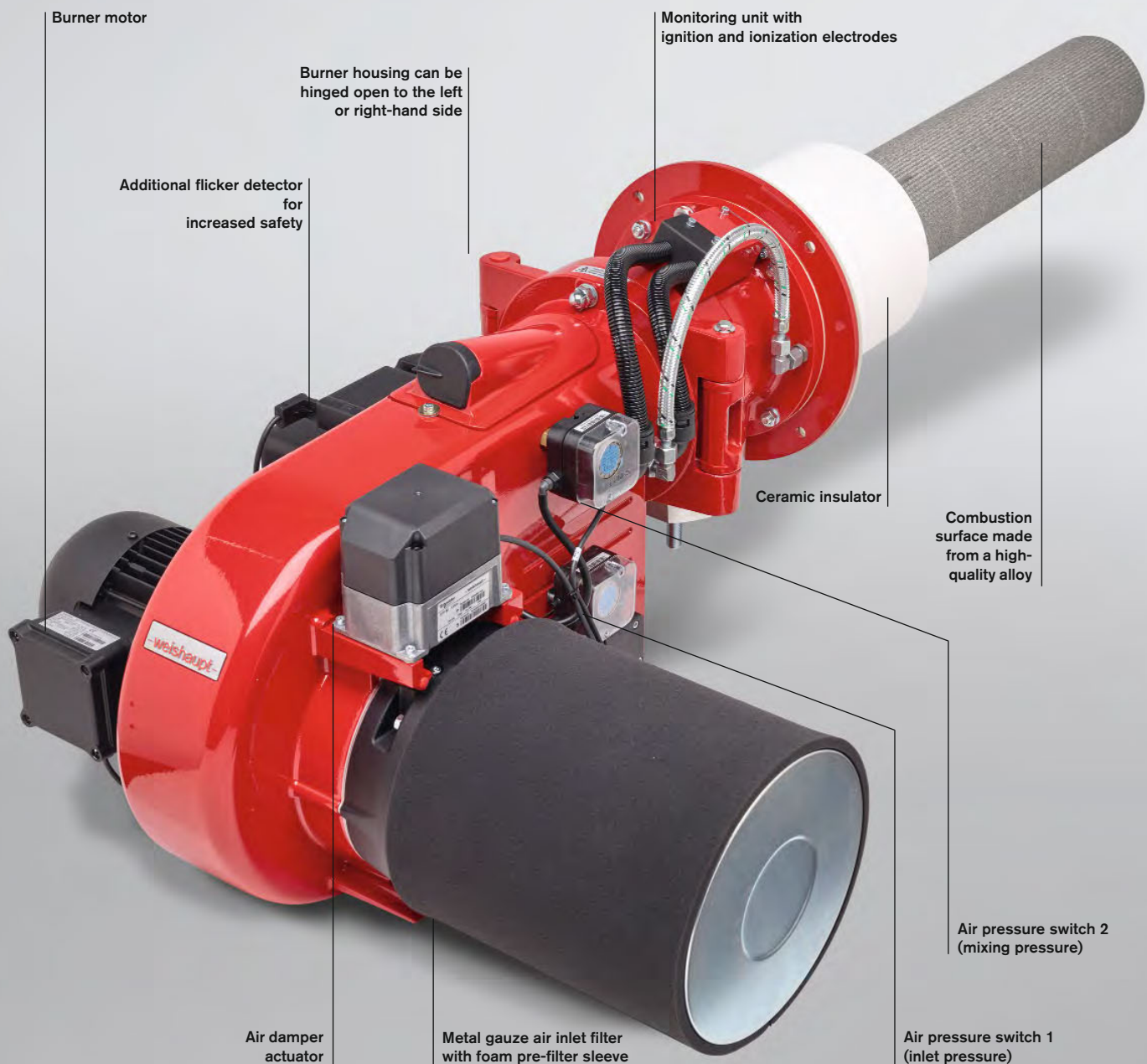
Stabilized surface combustion relies on an homogeneous gas / air mixture. For that reason, a completely new mixing assembly was developed for the PLN-version burners. A key feature is the separated feed of gas and air, the two media are not mixed together upstream the burner tube. A uniform mixture is created by the gas flow through the distributor and the combustion air that has been set in rotation by the swirl plate.

Stabilized surface combustion

The gas / air mix, which is under pressure, permeates the microweave alloy mat and combusts on its surface. The flame carpet thereby created has flame temperatures below 2,190 F (1,200 °C) and so the formation of thermal NO_x is inhibited. Single digit NO_x emission levels are now also a reality for medium-capacity burners.

One substantial benefit of this technology is to be found in the combustion chamber requirements. These can be considerably smaller than those found in typical boilers.

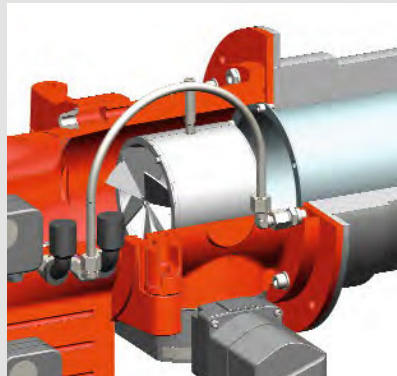
Weishaupt's PLN-version premix burners also have similar turndowns to their forced-draft siblings. The electronic compound regulation provided by the W-FM combustion manager can achieve turndown ratios of 7:1 with these burners.



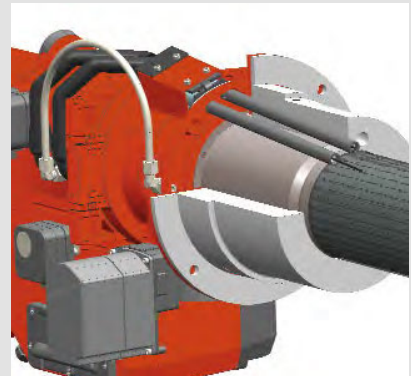
Simple and safe from installation to operation



Aerodynamically designed air damper assembly



The special mixing of gas and air ensures reliable ignition behaviour



A ceramic insulator provides optimal heat shielding to the mixing assembly and electrode unit

Ignition and monitoring

The ignition electrode and the ionization electrode (flamerod) are assembled together as a unit. The electrodes are fed through the ceramic insulator for protection against heat and they are also air cooled.

Optimal safety and reliability

The PLN-version burners are equipped with two monitoring systems. An ionization electrode monitors the flame on combustion surface, while a flame flicker detector secures the premix chamber and the burner tube.

Continuous monitoring

The air volume and the condition of the air filter are continuously monitored during burner operation by an additional air pressure switch. The necessary air volume is thereby always guaranteed.

Clean combustion air

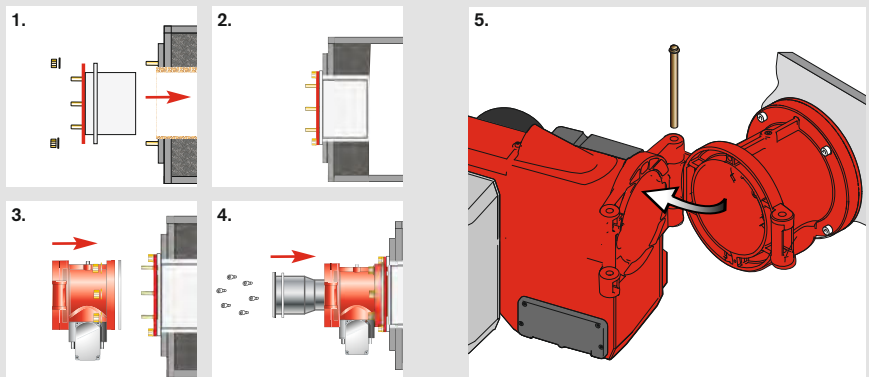
The combustion surface's alloy microweave mat can only distribute the gas /air mixture evenly if its pores are not blocked by particles. For this purpose Weishaupt therefore employs a special metal gauze air filter. An additional pre-filter sleeve is used to keep larger dust particles away from combustion surface. The foam pre-filter sleeve can be washed or replaced as required.

Simple installation / easy servicing

During installation, the burner flange should be mounted first to the heat exchanger, then combustion tube can be inserted afterwards. Burner combustion tube can be removed without completely dismounting the burner from the heat exchanger.

The burner is installed in five easy steps:

1. Installation of the ceramic insulator.
2. Check insertion depth and insulation between the burner and the refractory
3. Mount burner's hinged flange.
4. Insert the combustion surface.
(optional installation tool is available)
5. Mount burner to the hinged flange.



The burner hinges a full 90°, enabling the combustion surface to be removed through the mounted burner flange

Digital

Digital combustion management means optimum combustion figures, excellent repeatability and easy of use.

Weishaupt PLN-version gas burners are equipped as standard with electronic ratio controller and digital combustion management. Modern combustion technologies demand a precise and continually reproducible dosing of fuel and combustion air. This optimizes combustion efficiency and saves fuel.

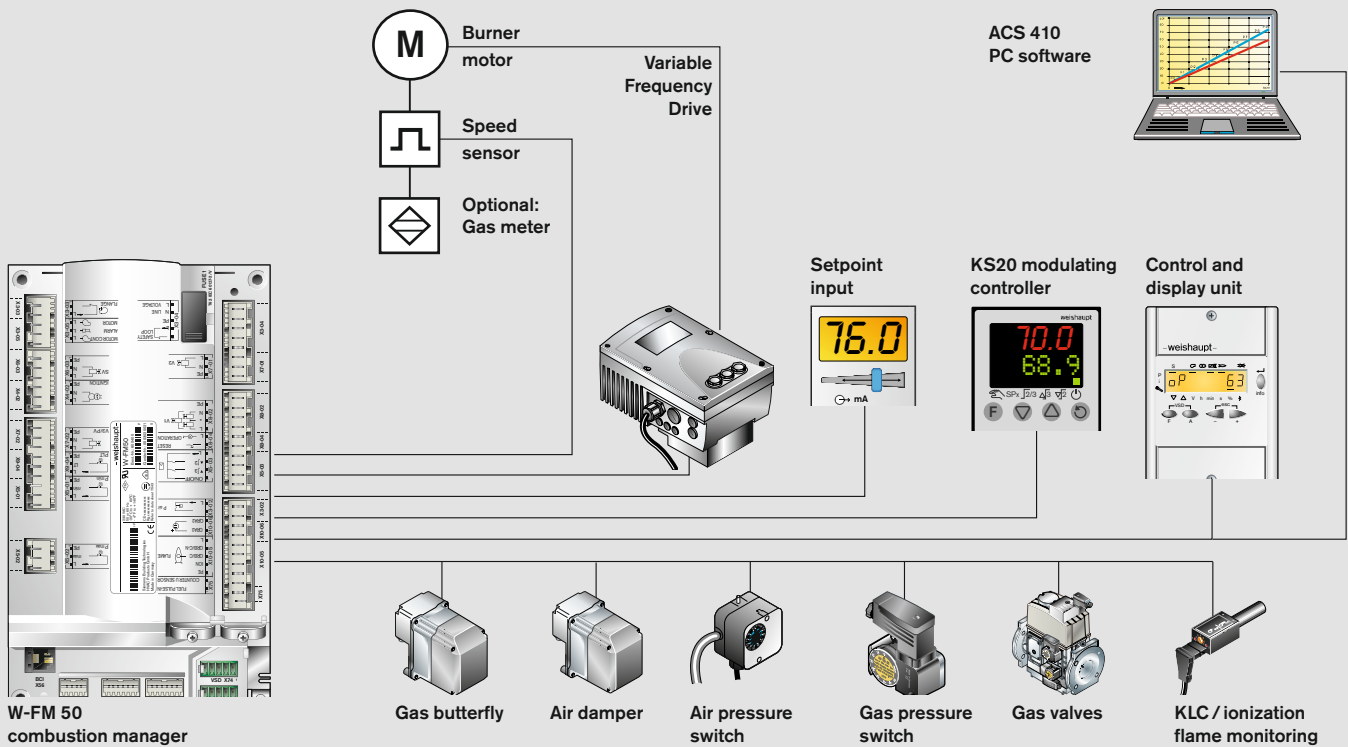
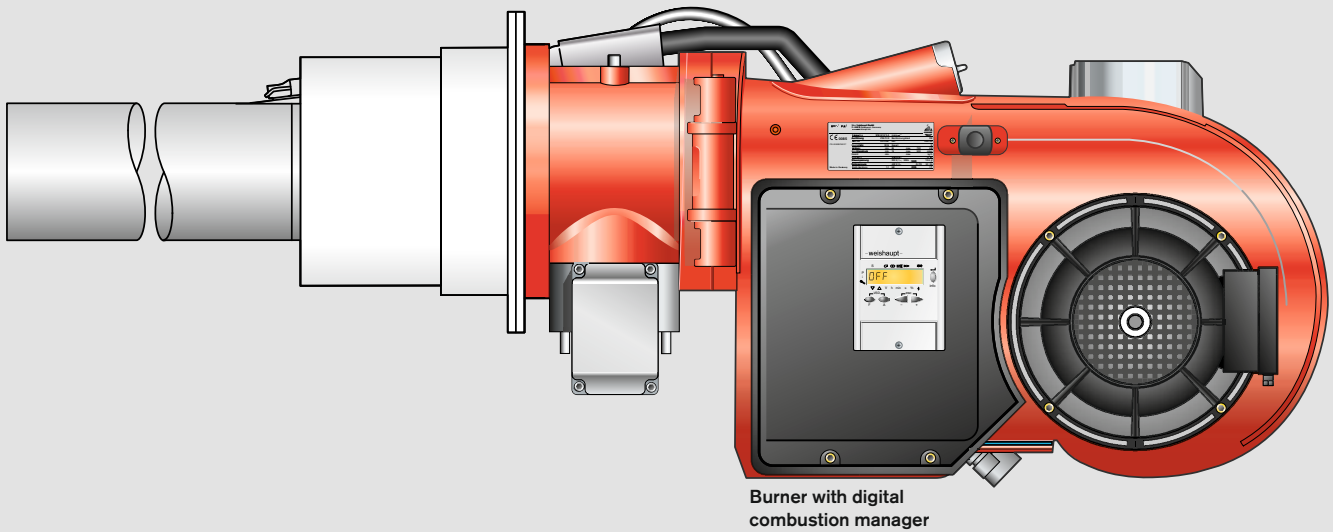
Simple operation

Burner's setting and control are carried out via a control and display unit. The display and control unit is directly connected to the combustion manager allowing direct access to parameter settings. The control and display unit depending on the combustion manager, employs either a language-neutral display or a clear text display with a choice of languages.

Variable speed drive reduces electrical consumption and facilitates a soft start of the combustion air fan. The use of VFD also reduces noise emissions by a considerable amount.

Features – digital combustion management	W-FM 50	W-FM 100	W-FM 200
Single-fuel operation	●	●	●
Intermittent firing	●	●	●
Continuous firing >24 h	●	●	●
Variable frequency drive	●	–	●
O ₂ module	–	–	●
ION/KLC flame sensor for continuous firing	●	●	●
Maximum number of actuators	2	4	6
Integrated PID controller with automatic adaption. Pt / Ni temperature sensor, 0/2–10 V, and 0/4–20 mA inputs for temperature / pressure	–	○	●
0/2–10 V and 0/4–20 mA setpoint input for temperature / pressure	–	○	●
Configurable 0/4–20 mA analogue output	–	○	●
Language-neutral ABE control unit	●	–	–
ABE control unit with multiple languages support	–	●	●
Removable ABE control unit (max. length of connecting line)	65 ft / 20 m	325 ft/ 100 m	325 ft/ 100 m
Fuel consumption meter (switchable)	● ¹⁾	–	●
Combustion efficiency display	–	–	●
Modbus RTU interface	●	●	●
PC-supported commissioning	●	●	●

● Standard ○ Optional ¹⁾ Not in conjunction with VFD



Specifications, control and burner nomenclature

Suitable fuels

Natural gas
Propane

Different type of fuel requires written confirmation from Weishaupt Corporation.

Applications

Weishaupt PLN-version burners are suitable for intermittent and continuous firing on:

- Installation on heat exchanger
- Hot water boiler
- Steam boiler and high pressure hot water boiler
- Intermittent and continuous operation
- Hot air generator ¹⁾

The combustion air must be free from any aggressive substances (Halogen, Chloride, Fluoride, etc) and contamination (dust, building materials, vapours, etc). For many cases an external air ducting to the burner is recommended as an option.

Permissible ambient conditions:

- Ambient temperature
 - 10 to +40 °C (14 to 104F)
 - 15 to +40 °C (5 to 104F)
- Air humidity: max. 80 % relative humidity, no condensation
- Suitable only for indoor operation
- For installation in unheated rooms under some circumstances special solutions are required (contact Weishaupt)

Any discrepancy from the above described applications requires written confirmation from Weishaupt Corporation. The maintenance interval could be shortened according to conditions where the burners are installed.

Approvals

The PLN series burners are in compliance with most European and North American applicable standards.

Control

Weishaupt PLN-version burners are suitable for sliding-two-stage or modulating operation, depending on the type of modulating controller. Throughout its operating range burner's output is matched to the heat demand.

These multiple control options make the WM series burners universally adaptable to various applications. Thus results in a smooth, trouble free start and reliable operation.

Installation position

The burner is suitable for horizontal and vertical mounting on the heat generator. The manufacturer's instructions should be observed.

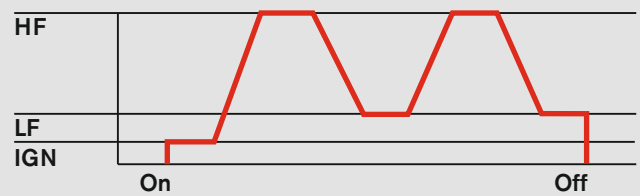
¹⁾ Please inquire

Operation with gas

Sliding-two-stage or modulating operation (ZM)

- Stepping motors adjust the capacity between low and high fire depending on the heat demand
- There is a gradual change between both operating points. There are no sudden, large changes in fuel throughput.
- Controller options:
 - W-FM 50 in conjunction with modulating controller
 - W-FM 100 with integral load controller
 - W-FM 200

sliding two stage



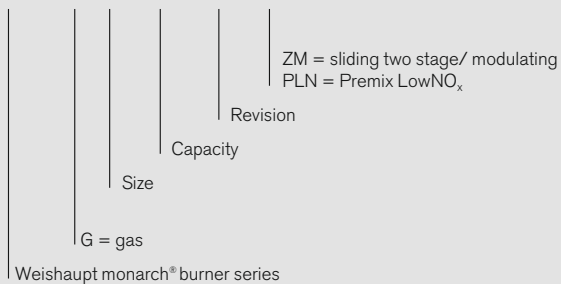
modulating



HF = Highfire
LF = Lowfire
IGN = Ignition

Nomenclatures

WM – G 10 / 3 –A ZM-PLN



Burner selection

WM-G10, version ZM-PLN

Burner model WM-G10/2-A ZM-PLN

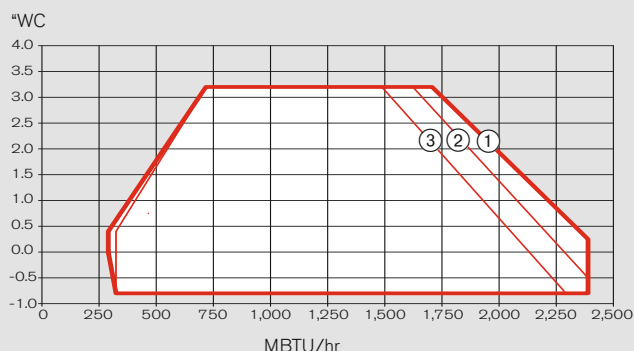
Combustion head WM10/2-PLN

Capacity MBTU/h Natural gas

290 – 2,390

Propane

325 – 2,390



— Natural gas
— Propane

Burner model WM-G10/4-A ZM-PLN

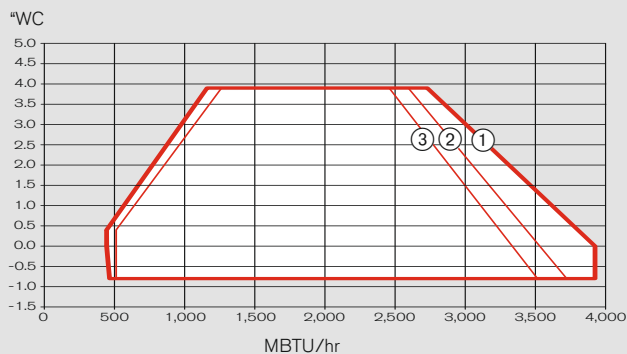
Combustion head WM10/3+4-PLN

Capacity MBTU/h Natural gas

445 – 3,925

Propane

515 – 3,925



Burner order numbers

Burner model	Version	Order No.
WM-G10/2-A	ZM-PLN	217 124 10
WM-G10/3-A	ZM-PLN	217 125 10
WM-G10/4-A	ZM-PLN	217 126 11

Burner model WM-G10/3-A ZM-PLN

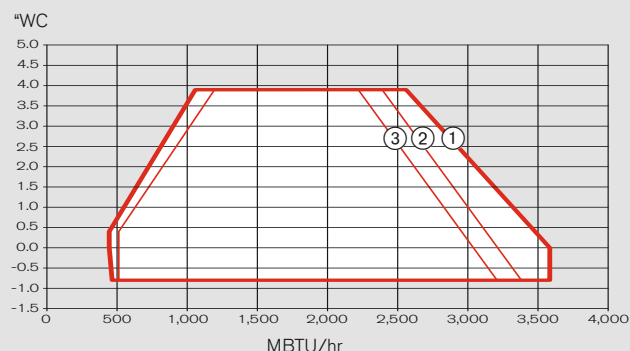
Combustion head WM10/3+4-PLN

Capacity MBTU/h Natural gas

445 – 3,585

Propane

515 – 3,585



The firing rates are based on an installation altitude of 0 ft (0 m). A reduction of burner capacity of 1 % for every 325 ft (100 m) should be taken into consideration in case of installation altitude above 0 ft.

Voltages and frequencies:

The burners are equipped with three phase motor in 208 - 600 V, 60 Hz as standard. Different voltage and frequency are available upon request.

Standard burner motor:

Insulation class F, protection IP 54.

Determining load point dependent on excess air
(See example on page 19)

	NO _x [ppm]		Setting		P _F factor ¹⁾
	N. Gas	P. Gas	O ₂ ²⁾	λ ²⁾	
①	30	75	5 %	1.28	1.24
②	15	30	7 %	1.46	1.61
③	9	–	8 %	1.56	1.84

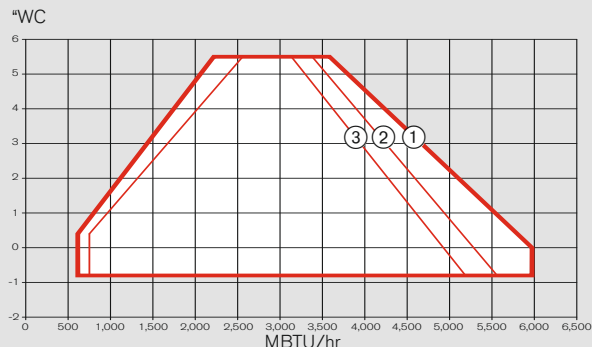
¹⁾ The correction factor is based on the combustion chamber resistance (P_F) at 3 % O₂

²⁾ Excess air and O₂ values are approximate only and may vary depending on site conditions.

Burner selection

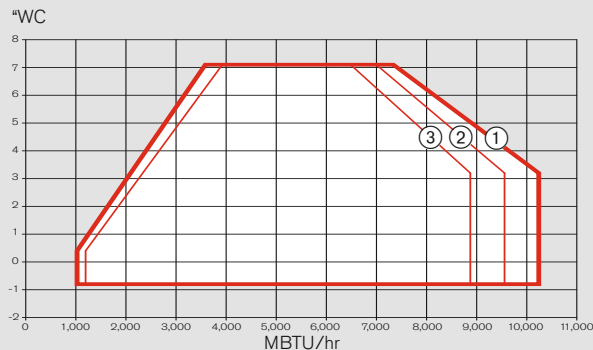
WM-G20, version ZM-PLN

Burner model WM-G20/2-A ZM-PLN
Combustion head WM-G20/2 PLN
Capacity MBTU/h Natural gas 615 – 5,970
 Propane 750 – 5,970



— Natural gas
 — Propane

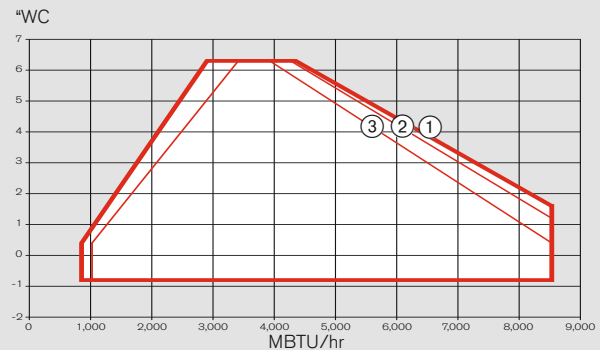
Burner model WM-G20/4-A ZM-PLN
Combustion head WM-G20/4 PLN
Capacity MBTU/h Natural gas 1,024 – 10,240
 Propane 1,195 – 10,240



Burner order numbers

Burner model	Version	Order No.
WM-G20/2-A	ZM-PLN	217 221 11
WM-G20/3-A	ZM-PLN	217 222 11
WM-G20/4-A	ZM-PLN	217 223 11

Burner model WM-G20/3-A ZM-PLN
Combustion head WM-G20/3 PLN
Capacity MBTU/h Natural gas 853 – 8,530
 Propane 1,025 – 8,530



The firing rates are based on an installation altitude of 0 ft (0 m). A reduction of burner capacity of 1 % for every 325 ft (100 m) should be taken into consideration in case of installation altitude above 0 ft.

Voltages and frequencies:

The burners are equipped with three phase motor in 208 - 600 V, 60 Hz as standard. Different voltage and frequency are available upon request.

Standard burner motor:

Insulation class F, protection IP 54.

Determining load point dependent on excess air
 (See example on page 19)

	NO _x [ppm]		Setting		P _F factor ¹⁾
	N. Gas	P. Gas	O ₂ ²⁾	λ ²⁾	
①	30	75	5 %	1.28	1.24
②	15	30	7 %	1.46	1.61
③	9	–	8 %	1.56	1.84

¹⁾ The correction factor is based on the combustion chamber resistance (P_F) at 3 % O₂.

²⁾ Excess air and O₂ values are approximate only and may vary depending on site conditions.

Example of calculation

Standard scope of supply

Determining the load point with regard to the required level of NO_x emissions

Example:

Burner firing rate

3,000 MBH

Combustion chamber resistance:

● Per appliance's manufacturer, with 3 % O₂

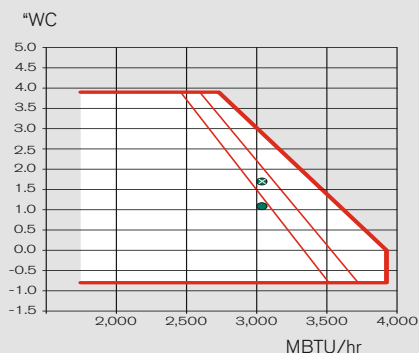
1.0"w.c.

⊗ For 15 ppm of NO_x, with 7 % O₂

1.6"w.c.

Installation altitude

sea level



Determining load point dependent on excess air

	NO _x [ppm]		Setting	P _F factor ¹⁾
	N. Gas	P. Gas	O ₂ ²⁾ λ ²⁾	
①	30	75	5 %	1.28
②	15	30	7 %	1.61
③	9	–	8 %	1.84

¹⁾ The correction factor is based on the combustion chamber resistance (P_F) at 3 % O₂.

²⁾ Excess air and O₂ values are approximate only and may vary depending on site conditions.

NO_x reference conditions:

Air temperature

t_a = 68F (20 °C)

Air humidity

x = 70 gr/lb (10 g/kg)

Natural gas

Cal = 1,000 BTU/cu-ft

Propane

Cal = 2,500 BTU/cu-ft

- Evaluation at each operating point
- No averaging
- No measurement uncertainty/ tolerance
- 3 pass heat exchanger

Description	WM-G10 ZM-PLN	WM-G20 ZM-PLN
Burner housing, hinged flange, housing cover, Weishaupt burner motor, air inlet housing, fan wheel, combustion head, ignition unit, ignition cable, ignition electrodes, combustion manager with display and operating unit, flame sensor, actuators, flange gasket, limit switch on hinged flange, mounting studs	●	●
Digital combustion manager W-FM 50 W-FM 100/ 200	● ○	● ○
Two main gas safety shut off valves	●	●
Gas butterfly valve	●	●
Air pressure switch	●	●
Low and high gas pressure switches	●	●
Actuators for electronic fuel air ratio controller W-FM: Air damper stepping motor Gas butterfly valve stepping motor	● ●	● ●
IP 54 protection	●	●

● Standard
○ Optional

Technical data

Gas burners		WM-G10/2-A ZM-PLN	WM-G10/3-A ZM-PLN	WM-G10/4-A ZM-PLN
Burner motor	Weishaupt model	WM-D 90/90-2/1K0	WM-D 90/110-2/1K5	WM-D 90/110-2/1K9
Rated power	HP (kW)	1.3 (1)	2.13 (1.6)	2.5 (1.9)
Full load amps (FLA)	A (@460 V)	2.0	3.1	3.2
Motor fuse (YΔ start)	A minimum	10A (external)	15A (external)	15A (externally)
Speed (60 Hz)	rpm	3,500	3,500	3,120 (55 Hz)
Combustion manager	model	W-FM50/ W-FM100	W-FM50/ W-FM100	W-FM50/ W-FM100
Flame monitoring	model	ION	ION	ION
Air/ gas actuator	model	SQM33/ SQM45	SQM33/ SQM45	SQM33/ SQM45
Weight (excl. gas train)	lbs (kg)	163 (74)	165 (75)	165 (75)

Gas burners		WM-G20/2-A ZM-PLN	WM-G20/3-A ZM-PLN	WM-G20/4-A ZM-PLN
Burner motor	Weishaupt model	WM-D 112/140-2/3K0	WM-D 112/170-2/4K5	WM-D 112/170-2/7K0
Rated power	HP (kW)	4.2 (3.2)	6.7 (5.0)	9.3 (7.0)
Full load amps (FLA)	A (@460 V)	6.2	8.7	15
Motor fuse (YΔ start)	A minimum	25A (external)	30A (external)	40A (external)
Speed (60 Hz)	rpm	3,540	3,530	3,520
Combustion manager	model	W-FM50/ W-FM100	W-FM50/ W-FM100	W-FM50/ W-FM100
Flame monitoring	model	ION	ION	ION
Air/ gas actuator	model	SQM33/ SQM45	SQM33/ SQM45	SQM33/ SQM45
Weight (excl. gas train)	lbs (kg)	209 (95)	220 (100)	242 (110)

Voltages and frequencies:

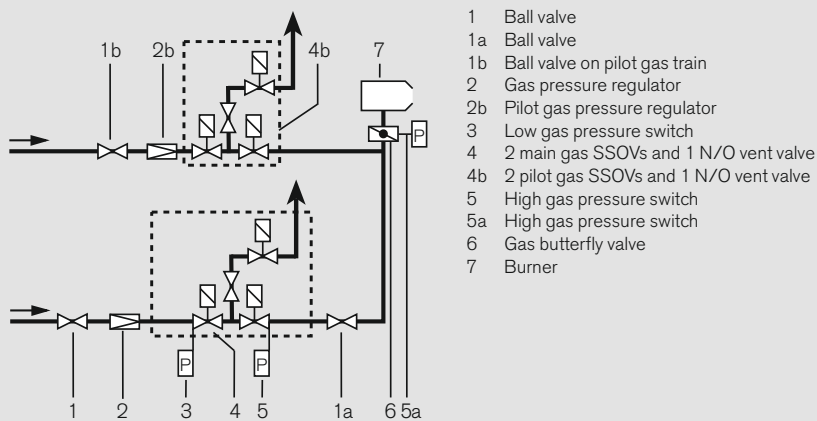
The burners are equipped with three phase motor in 208 - 600 V, 60 Hz as standard.
Different voltage and frequency are available upon request.

Standard burner motor:

Insulation class F, protection IP 54.

Fuel systems

Gas train schematic*



* The above schematic shows typical gas train configuration only. The actual gas train configuration shipped with burner might differ depending on applicable codes/ regulation and application.

Gas train arrangement

For boiler with hinged door the gas train must be installed on the opposite side of the boiler door hinge.

Gas train installation

Gas train must be mounted tension free. Do not compensate misalignment by over tightening. Distance between burner and gas valves should be as small as possible. Pay attention to the correct gas flow direction.

Gas train support

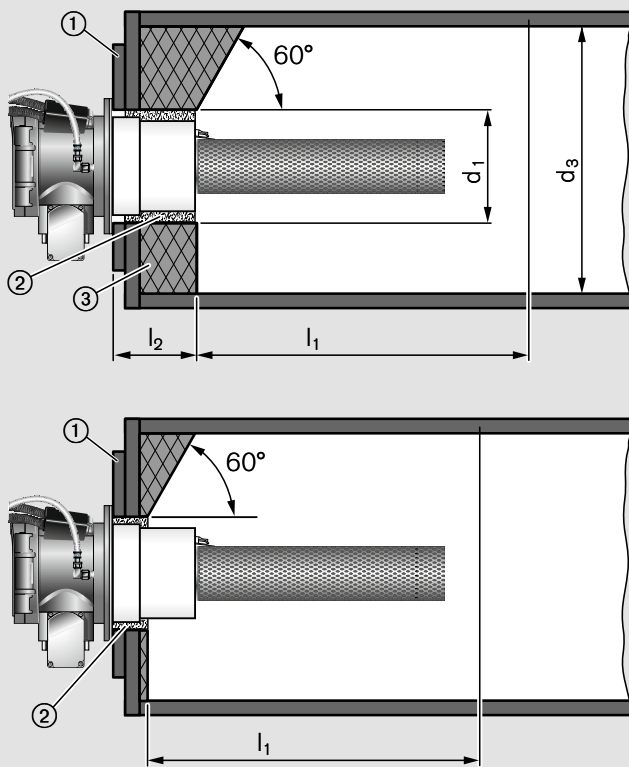
The gas train must be fixed and supported securely. They must not be allowed to vibrate during operation. Support suitable for the site should be fitted during installation.

Gas meter

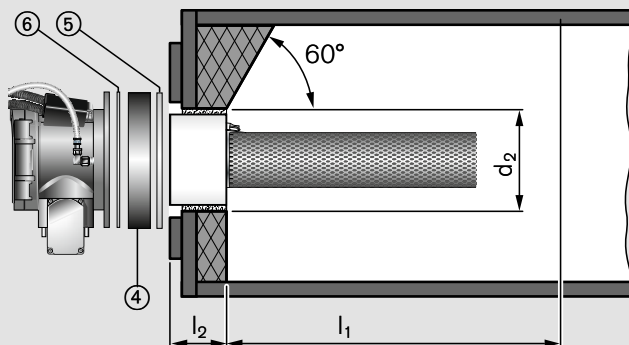
For commissioning a gas meter is required to verify exact gas consumption.

Dimensions

Appliance without spacer ring



Appliance with spacer ring



Minimum combustion chamber sizes

WM-G10 ZM-PLN

d ₁	Minimum boiler opening without spacer ring	10.2" (260 mm)
d ₂	Minimum boiler opening with spacer ring	9.6" (244 mm)
d ₃	Minimum combustion chamber diameter	13.8" (350 mm)
l ₁	Minimum combustion chamber length	
	WM10/2	33.1" (840 mm)
	WM10/3	47.2" (1,200 mm)
	WM10/4	47.2" (1,200 mm)
l ₂	Maximum boiler door depth, including refractory / insulation,	
	without spacer ring	8.7" (220 mm)
	with spacer ring and gasket	5.7" (145 mm)

WM-G20 ZM-PLN

d ₁	Minimum boiler opening without spacer ring	14.6" (370 mm)
d ₂	Minimum boiler opening with spacer ring	13.6" (345 mm)
d ₃	Minimum combustion chamber diameter	17.7" (450 mm)
l ₁	Minimum combustion chamber length	
	WM20/2	48.4" (1,230 mm)
	WM20/3	64.2" (1,630 mm)
	WM20/4	72" (1,830 mm)
l ₂	Maximum boiler door depth, including refractory / insulation,	
	without spacer ring	8.7" (220 mm)
	with spacer ring and gasket	5.7" (145 mm)

Legend

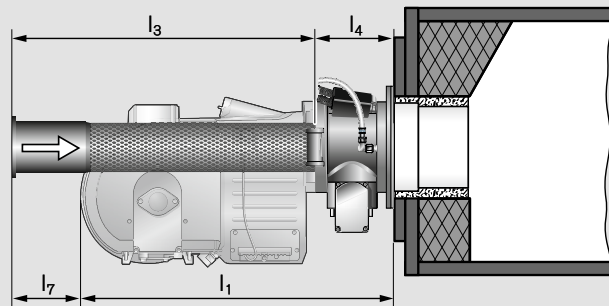
- ① Mounting plate
(WM-G20 ZM-PLN: Depth ≥ 5/16" (8 mm) for installations with spacer ring)
- ② Gap
- ③ Refractory / insulation
- ④ Spacer ring, WM-G10 ZM-PLN: 2.9" (74 mm)
Spacer ring, WM-G20 ZM-PLN: 2.8" (72 mm)
(Optional for boilers with narrow burner opening)
- ⑤ Flange gasket: 5/16" (8 mm)
- ⑥ Gasket WM-G10 ZM-PLN: 1/16" (2 mm)
Gasket WM-G20 ZM-PLN: 5/16" (8 mm)

Note:

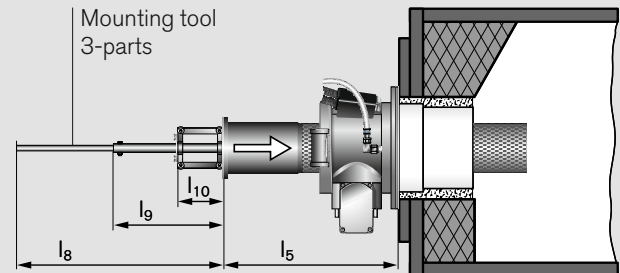
The boiler door refractory / insulation may be tapered (≥ 60°).

Installation and removal of burner's tubes Dimensions for WM-G10 and WM-G20 ZM-PLN

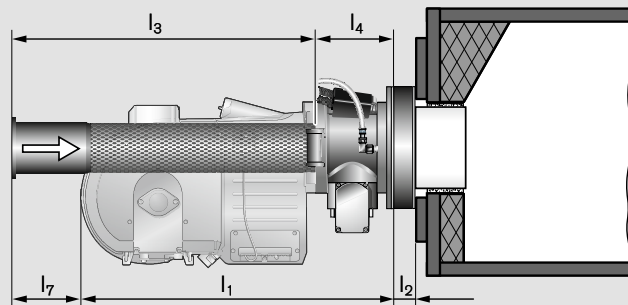
WM-G ZM-PLN without spacer ring



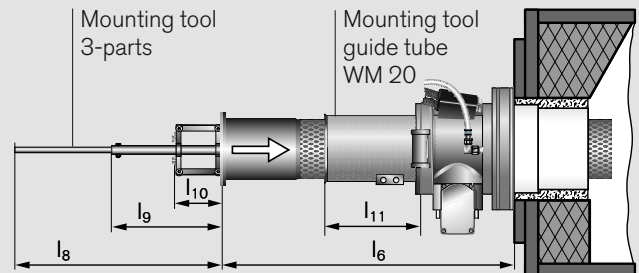
Mounting tool – minimum space requirement
w/o spacer ring



WM-G ZM-PLN with spacer ring



Mounting tool – minimum space requirement
with spacer ring



Burner model	Dimensions in inches (top) and mm (bottom)										
	l ₁	l ₂	l ₃	l ₄	l ₅	l ₆	l ₇	l ₈	l ₉	l ₁₀	l ₁₁
WM-G10/2-A ZM-PLN	32.8 833	2.9 74	33.5 852	8.2 208	41.7 1060	44.6 1134	8.9 227	23.0 585	12.0 305	6.1 155	–
WM-G10/3-A ZM-PLN	32.8 833	2.9 74	47.9 1216	8.2 208	56.1 1424	59.0 1498	23.3 591	23.0 585	12.0 305	6.1 155	–
WM-G10/4-A ZM-PLN	32.8 833	2.9 74	47.9 1216	8.2 208	56.1 1424	59.0 1498	23.3 591	23.0 585	12.0 305	6.1 155	–
WM-G20/2-A ZM-PLN	39.8 1010	2.8 72	41.1 1044	9.4 238	62.7 1592	65.5 1664	22.9 582	23.0 585	12.0 305	6.1 155	12.2 310
WM-G20/3-A ZM-PLN	39.8 1010	2.8 72	56.9 1444	9.4 238	78.4 1992	81.3 2064	38.7 982	23.0 585	12.0 305	6.1 155	12.2 310
WM-G20/4-A ZM-PLN	39.8 1010	2.8 72	64.6 1640	9.4 238	86.1 2188	89.0 2260	46.4 1178	23.0 585	12.0 305	6.1 155	12.2 310

– weishaupt –

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Regular maintenance reduces heating costs and environmental pollution. Only a properly adjusted burner can save energy and be environmentally friendly. Behind each Weishaupt burner stands the whole Weishaupt customer service organization. The outstanding efforts made in maintenance and service justify the enormous trust placed in Weishaupt's burners, for at Weishaupt, product and customer service belong together.

Weishaupt customer service is there for you all year round. Whenever you need help, be it the supply of spare parts, technical advice or a site visit. We are there when you need us.

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Diesel generator set QST30 series engine

680 kW - 1000 kW 60 Hz



Description

Cummins® commercial generator sets are fully integrated power generation systems providing optimum performance, reliability and versatility for stationary Standby and Prime power applications.

Features

Cummins heavy-duty engine - Rugged 4-cycle, industrial diesel delivers reliable power, low emissions and fast response to load changes.

Alternator - Several alternator sizes offer selectable motor starting capability with low reactance 2/3 pitch windings, low waveform distortion with non-linear loads and fault clearing short-circuit capability.

Permanent Magnet Generator (PMG) - Offers enhanced motor starting and fault clearing short circuit capability.

Circuit breakers - Option for manually-and/or electrically-operated circuit breakers.

Control system - The PowerCommand® electronic control is standard equipment and provides total generator set system integration including automatic remote starting/stopping, precise frequency and voltage regulation, alarm and status message display, AmpSentry™ protection, output metering, auto-shutdown at fault detection and NFPA 110 Level 1 compliance.

Masterless Paralleling - An optional electrically operated circuit breaker can be added for a simple masterless paralleling solution.

Cooling system - Standard integral set-mounted radiator system, designed and tested for rated ambient temperatures, simplifies facility design requirements for rejected heat.

NFPA - The generator set accepts full rated load in a single step in accordance with NFPA 110 for Level 1 systems.

Warranty and service - Backed by a comprehensive warranty and worldwide distributor network.

Model	Standby rating	Prime rating	Continuous rating	Data sheets
	60 Hz kW (kVA)	60 Hz kW (kVA)	60 Hz kW (kVA)	60 Hz
DQFAA	750 (938)	680 (850)		D-3329
DQFAB	800 (1000)	725 (907)		D-3330
DQFAC	900 (1125)	818 (1023)		D-3331
DQFAD	1000 (1250)	900 (1125)		D-3332

Generator set specifications

Performance Class	Genset models have been tested in accordance with ISO 8528-5. Consult factory for transient performance information.
Voltage regulation, no load to full load	± 0.5%
Random voltage variation	± 0.5%
Frequency regulation	Isochronous
Random frequency variation	± 0.25%
Electromagnetic Compatibility Performance	Emissions to EN 61000-6-2:2005 Immunity to EN 61000-6-4:2007+A1:2011

Engine specifications

Bore	140 mm (5.51 in.)
Stroke	165.0 mm (6.5 in.)
Displacement	30.5 L (1860 in ³)
Cylinder block	Cast iron, V 12 cylinder
Battery capacity	1600 amps minimum at ambient temperature of -18 °C to 0 °C (0 °F to 32 °F)
Battery charging alternator	35 amps
Starting voltage	24 volt, negative ground
Fuel system	Direct injection: number 2 diesel fuel, fuel filter, automatic electric fuel shutoff
Fuel filter	Triple element, 10 micron filtration, spin-on fuel filters with water separator
Air cleaner type	Dry replaceable element
Lube oil filter type(s)	Four spin-on, combination full flow filter and bypass filters
Standard cooling system	High ambient radiator

Alternator specifications

Design	Brushless, 4 pole, drip-proof, revolving field
Stator	2/3 pitch
Rotor	Single bearing flexible discs
Insulation system	Class H on low and medium voltage, Class F on high voltage
Standard temperature rise	125 °C Standby at 40 °C ambient
Exciter type	PMG (Permanent Magnet Generator)
Phase rotation	A (U), B (V), C (W)
Alternator cooling	Direct drive centrifugal blower fan
AC waveform Total Harmonic Distortion (THDV)	< 5% no load to full linear load, < 3% for any single harmonic

Available voltages

60 Hz Line – Neutral/Line - Line

- | | | | |
|-----------|-----------|-----------|-----------|
| • 120/208 | • 220/380 | • 240/416 | • 347/600 |
| • 139/240 | • 230/400 | • 277/480 | |

Note: Consult factory for other voltages.

Generator set options

Engine

- 208/240/480 V coolant heater for ambient above 4.5 °C (40 °F)
- 208/240/480 V coolant heater for ambient below 4.5 °C (40 °F)

Control panel

- PowerCommand 3.3 with Masterless Load Demand (MLD)
- Run relay package
- Ground fault indication
- Paralleling configuration

- Remote fault signal package
- Exhaust gas temperature sensor
- 120/240 V 100 W control anti-condensation heater

Alternator

- 80 °C rise
- 105 °C rise
- 125 °C rise
- 120/240 V 300 W anti-condensation heater
- Temperature sensor - RTDs, 2-phase

- Temperature sensor – alternator bearing RTD
- Differential current transformers

Exhaust system

- Critical grade exhaust silencer
- Exhaust packages
- Industrial grade exhaust silencer
- Residential grade exhaust silencer

Cooling system

- High ambient 50 °C radiator

Generator set

- AC entrance box
- Battery
- Battery rack with hold-down - floor standing
- Circuit breaker - set mounted
- Disconnect switch - set mounted
- PowerCommand network
- Remote annunciator panel
- Spring isolators
- 2 year warranty
- 5 year warranty
- 10 year major components warranty

Note: Some options may not be available on all models - consult factory for availability.

PowerCommand 3.3 Control System



An integrated microprocessor based generator set control system providing voltage regulation, engine protection, alternator protection, operator interface and isochronous governing. Refer to document S-1570 for more detailed information on the control.

AmpSentry – Includes integral AmpSentry protection, which provides a full range of alternator protection functions that are matched to the alternator provided.

Power management – Control function provides battery monitoring and testing features and smart starting control system.

Advanced control methodology – Three phase sensing, full wave rectified voltage regulation, with a PWM output for stable operation with all load types.

Communications interface – Control comes standard with PCCNet and Modbus® interface.

Service - InPower™ PC-based service tool available for detailed diagnostics, setup, data logging and fault simulation.

Easily upgradeable – PowerCommand controls are designed with common control interfaces.

Reliable design – The control system is designed for reliable operation in harsh environment.

Multi-language support

Operator panel features

Operator/display functions

- Displays paralleling breaker status
- Provides direct control of the paralleling breaker
- 320 x 240 pixels graphic LED backlight LCD

- Auto, manual, start, stop, fault reset and lamp test/panel lamp switches
- Alpha-numeric display with pushbuttons
- LED lamps indicating generator set running, remote start, not in auto, common shutdown, common warning, manual run mode, auto mode and stop

Paralleling control functions

- First Start Sensor System selects first generator set to close to bus
- Phase Lock Loop Synchronizer with voltage matching
- Sync check relay
- Isochronous kW and kVar load sharing
- Load govern control for utility paralleling
- Extended Paralleling (Base Load/Peak Shave) Mode
- Digital power transfer control, for use with a breaker pair to provide open transition, closed transition, ramping closed transition, peaking and base load functions,
- Alternator data
- Line-to-Neutral and Line-to-Line AC volts
- 3-phase AC current
- Frequency
- kW, kVar, power factor kVA (three phase and total)
- Engine data
- DC voltage
- Engine speed
- Lube oil pressure and temperature
- Coolant temperature
- Comprehensive FAE data (where applicable)
- Other data
- Genset model data
- Start attempts, starts, running hours, kW hours
- Load profile (operating hours at % load in 5% increments)
- Fault history
- Data logging and fault simulation (requires InPower)

For more information contact your local Cummins distributor or visit power.cummins.com

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Standard control functions

Digital governing

- Integrated digital electronic isochronous governor
- Temperature dynamic governing

Digital voltage regulation

- Integrated digital electronic voltage regulator
- 3-phase, 4-wire Line-to-Line sensing
- Configurable torque matching

AmpSentry AC protection

- AmpSentry protective relay
- Over current and short circuit shutdown
- Over current warning
- Single and three phase fault regulation
- Over and under voltage shutdown
- Over and under frequency shutdown
- Overload warning with alarm contact
- Reverse power and reverse Var shutdown
- Field overload shutdown

Engine protection

- Battery voltage monitoring, protection and testing
- Overspeed shutdown
- Low oil pressure warning and shutdown
- High coolant temperature warning and shutdown
- Low coolant level warning or shutdown
- Low coolant temperature warning
- Fail to start (overcrank) shutdown
- Fail to crank shutdown
- Cranking lockout
- Sensor failure indication
- Low fuel level warning or shutdown
- Fuel-in-rupture-basin warning or shutdown
- Full authority electronic engine protection

Control functions

- Time delay start and cool down
- Real time clock for fault and event time stamping
- Exerciser clock and time of day start/stop
- Data logging
- Cycle cranking
- Load shed
- Configurable inputs and outputs (4)
- Remote emergency stop

Options

- Auxiliary output relays (2)

Ratings definitions

Emergency Standby Power (ESP):

Applicable for supplying power continuously to varying electrical loads for the duration of power interruption of a reliable utility source. Emergency Standby Power (ESP) is in accordance with ISO 8528 and ISO 3046-1, obtained and corrected in accordance with ISO 15550.

Limited-Time Running Power (LTP):

Applicable for supplying power to a constant electrical load for limited hours. Limited-Time running Power (LTP) is in accordance with ISO 8528.

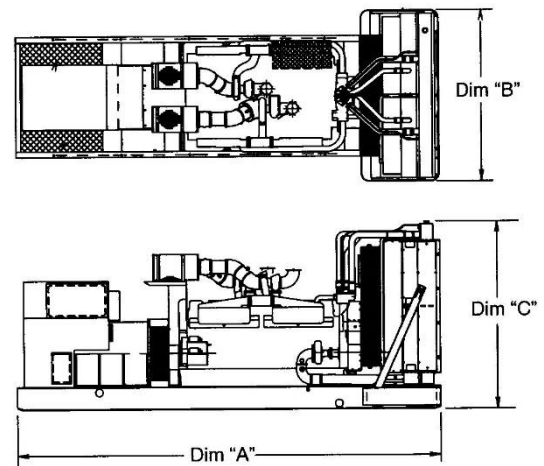
Prime Power (PRP):

Applicable for supplying power to varying electrical load for unlimited hours. Prime Power (PRP) is in accordance with ISO 8528. Ten percent overload capability is available in accordance with ISO 3046-1. Data shown above represents gross engine performance and capabilities as per ISO 3046-1, obtained and corrected in accordance with ISO 15550.

Base Load (Continuous) Power (COP):

Applicable for supplying power continuously to a constant load up to the full output rating for unlimited hours. No sustained overload capability is available for this rating. Consult authorized distributor for rating. (Equivalent to Continuous Power in accordance with ISO 8528 and ISO 3046-1, obtained and corrected in accordance with ISO 15550).

This rating is not applicable to all generator set models.



- This outline drawing is for reference only. See respective model data sheet for specific model outline drawing number.

For more information contact your local Cummins distributor or visit power.cummins.com

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Model	Dim 'A' mm (in.)	Dim 'B' mm (in.)	Dim 'C' mm (in.)	Set Weight dry* (lb)	Set Weight wet* (lb)
DQFAA	4287 (168.8)	1990 (78.3)	2355 (92.7)	6671 (14707)	6969 (15363)
DQFAB	4287 (168.8)	1990 (78.3)	2355 (92.7)	6894 (15199)	7192 (15855)
DQFAC	4287 (168.8)	1990 (78.3)	2355 (92.7)	7373 (16254)	7670 (16910)
DQFAD	4287 (168.8)	1990 (78.3)	2355 (92.7)	7631 (16824)	7929 (17480)

* Weights represent a set with standard features. See outline drawings for weights of other configurations.

Codes and standards

Codes or standards compliance may not be available with all model configurations – consult factory for availability.

ISO 9001 ISO 14001 ISO 45001	This product was manufactured in a facility whose quality management system is certified to ISO 9001 and its Health Safety Environmental Management Systems certified to ISO 14001 and ISO 45001.		This product is listed to UL 2200, Stationary Engine Generator Assemblies.
	The Prototype Test Support (PTS) program verifies the performance integrity of the generator set design. Cummins products bearing the PTS symbol meet the prototype test requirements of NFPA 110 for Level 1 systems.	U.S. EPA	Engine certified to Stationary Emergency U.S. EPA New Source Performance Standards, 40 CFR 60 subpart IIII Tier 2 exhaust emission levels. U.S. applications must be applied per this EPA regulation.
	All genset models are available as CSA certified to CSA C22.2 No.100	International Building Code	The generator set package is available certified for seismic application in accordance with International Building Code.

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Exemption 4: CBI

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Heat Transfer That Exceeds Expectations

A photograph of a worker in a blue uniform holding a white hard hat. The worker is standing in an industrial facility with complex piping, valves, and machinery in the background. The lighting is bright, and the overall scene conveys a sense of industrial safety and efficiency.

ACCU-THERM® PLATE HEAT EXCHANGERS

MUELLER

Performance Guaranteed

Heating and cooling processes can be difficult tasks that require time and money. Whether you are looking to conserve energy, save floor space, or make your operation more efficient, Mueller Accu-Therm® has helped improve operations in a number of different industries. Paul Mueller Company's Accu-Therm plate heat exchangers are designed to provide you worry-free, highly efficient heat transfer performance - whether you are processing simple fluids, viscous solutions, or particulates.

Every Mueller Accu-Therm unit receives rigorous quality inspections for leaks and pressure capabilities. We factor in safety, precision, maintenance and the needs of the application being performed. Combining these aspects into the design will be evident in your final product and for years to come. If your plate heat exchanger does not operate according to your exact specifications, our service technicians will make the necessary adjustments immediately.



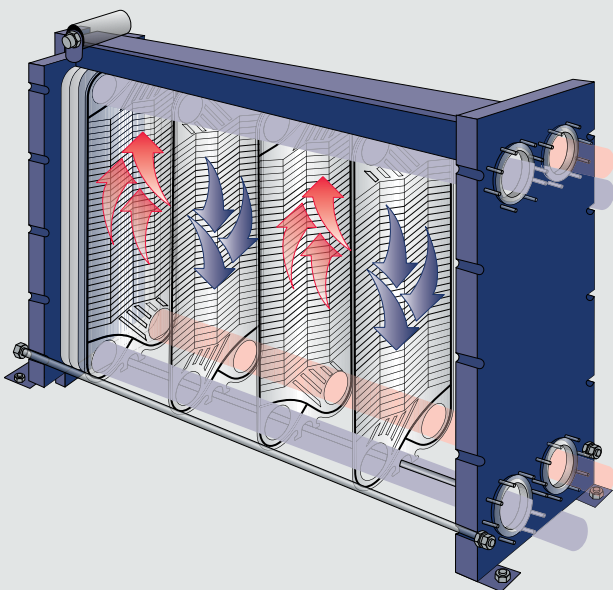


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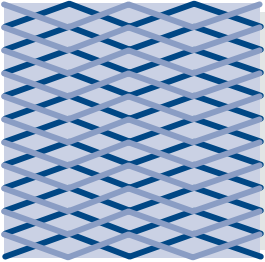
How Does Mueller Accu-Therm® Work?

An Accu-Therm Plate Heat Exchanger (PHE) consists of a series of embossed heat transfer plates with gaskets around the perimeter of every plate to contain pressure and control the flow of each medium. They can be designed for multiple fluids or thermal requirements in a single frame. Gasketed plates are assembled in a pack, mounted on upper and lower guide rails, and compressed between two end-frames with compression bolts.



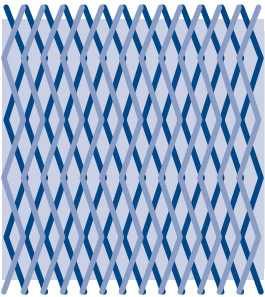
1. Fluids enter the PHE through end-frame connections and are distributed to the plates through portholes in the plates.
2. Directed by the gaskets, the fluid to be heated or cooled flows down one side of each plate, while the heating or cooling medium flows in the opposite direction on the other side of the plate.
3. The temperature difference created by these opposite flows results in the closest possible approach temperature for maximum heat transfer efficiency.
4. The heated or cooled fluid exits the PHE through end-frame connections.

Plate Patterns



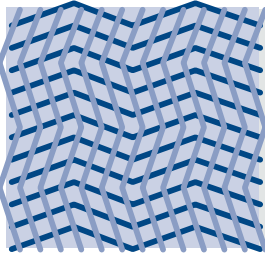
Horizontal (H)

Horizontal herringbone embossing. Highest heat transfer coefficients and pressure drop.



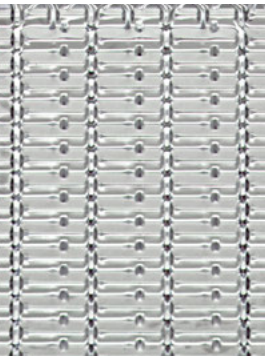
Vertical (V)

Vertical herringbone embossing. Slightly lower heat transfer coefficients and pressure drops.



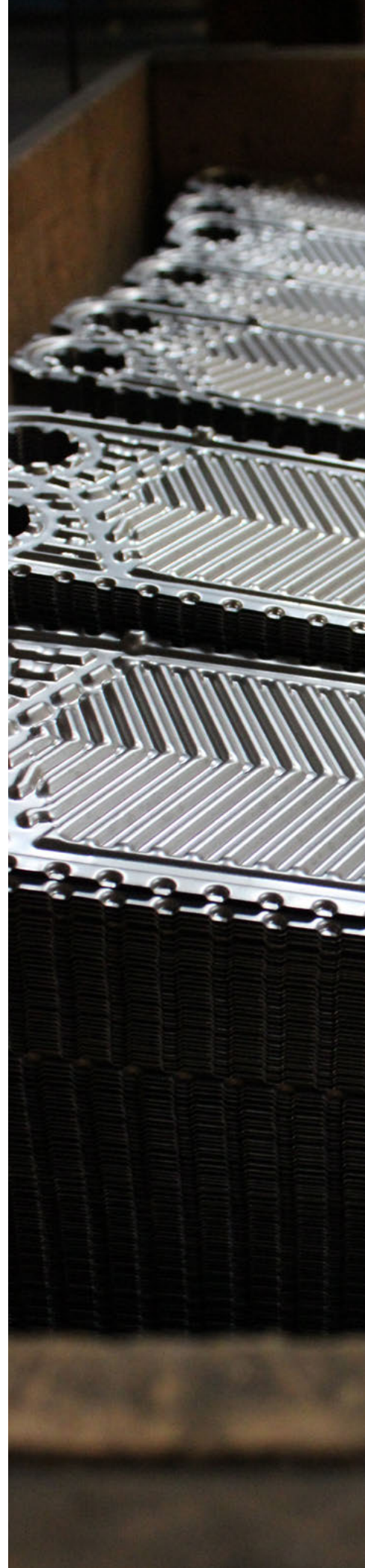
Combination (H/V)

A combination of H and V plates for an intermediate range of heat transfer coefficients and pressure drop.



Free-Flow

Open fluid-flow channel, ideal for viscous products, slurries, and effluent streams that contain particles and fibers which can block the flow channels and plug up conventional heat exchangers.



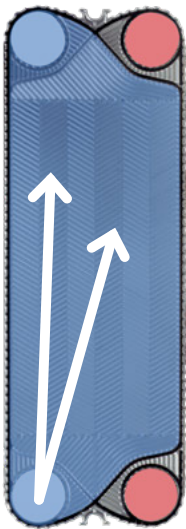
Gaskets

Mueller Accu-Therm plate heat exchangers provide efficient heat transfer by design. They can be designed for multiple fluids or thermal requirements in a single frame. The flow to individual passages between plates is controlled by alternate placement of port gaskets. Within the heat exchanger, the fluid to be heated (or cooled) flows down one side of each plate, while the heating (or cooling) medium flows in the opposite direction on the other side of the plate without cross contamination.

MATERIALS OF CONSTRUCTION:

- Nitrile (NBR)
- Ethylene Propylene Rubber
- Silicone
- Viton®/FKM
- Butyl (resin cured)

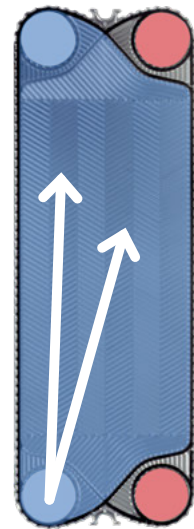
FIRST FLOW PLATE



SECOND FLOW PLATE



THIRD FLOW PLATE



Replacement Parts

When replacement parts are needed for your plate heat exchanger, contact our responsive team to get your equipment operating at maximum efficiency. Visit paulmueller.com/heat-transfer-parts and fill out the form to receive a quote or more information about replacement parts including:

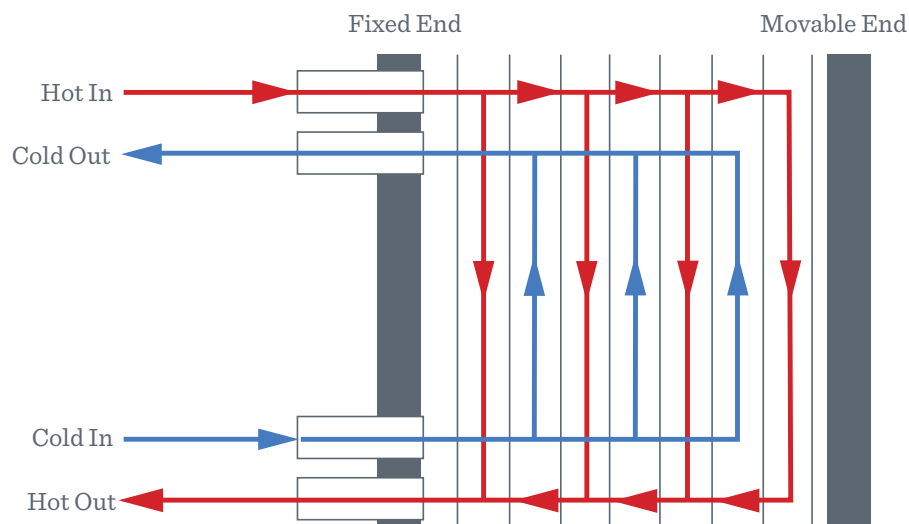
- Plate and gasket pack
- Loose gaskets
- Plate assemblies
- Port rings
- Boot liners
- Compression bolts
- Upper and lower guide bars
- Fixable and movable frames

Configurations

While hot and cold fluids flow in opposite directions across a single plate, the flow pattern between plates can vary. Plate heat exchanger flow patterns can be single or multi-pass.

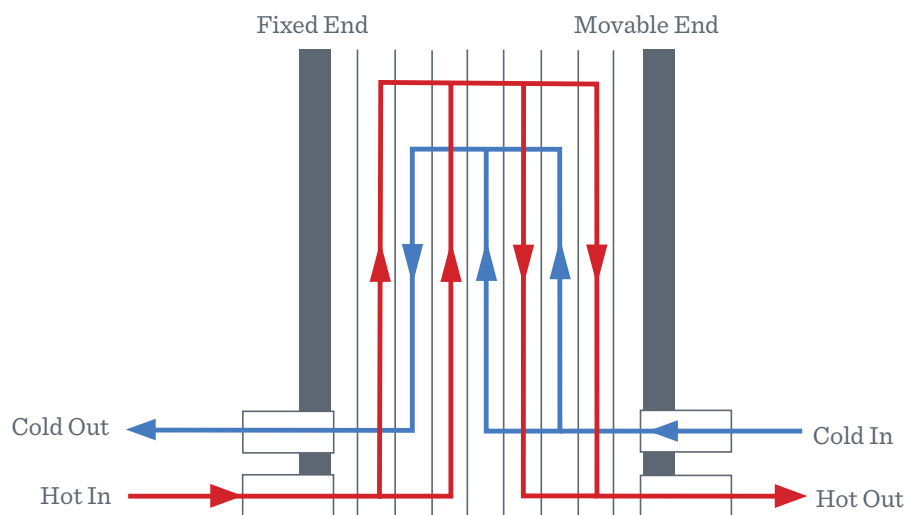
Single Pass

A single pass arrangement means each fluid flows in the same respective direction across all the plates in the unit. Single pass units are suitable for most applications.



Multi-Pass

A multi-pass arrangement is designed so fluids can change their respective flow directions. Extremely close temperatures or large temperature differences may call for a multi-pass configuration.



Types of Plate Heat Exchangers

Accu-Therm Plate Heat Exchanger

Accu-Therm Plate Heat Exchangers can be found in a wide variety of industries for a multitude of applications. Compact size, ease of maintenance, and high efficiency make them ideal for nearly any heating or cooling task. Available in an extensive range of sizes, alloys, and frame configurations to meet your needs in industries like HVAC, Chemical, Oil & Gas, and more.



Sanitary Plate Heat Exchanger

The sanitary Accu-Therm plate heat exchanger is designed to meet a variety of sanitary process applications such as Brewing, Dairy, and Food Processing. It meets or surpasses the most stringent sanitary requirements.



PHE FRAME TYPES

B FRAME - For larger units or for applications where it is desirable to have heat transfer plates hanging from the upper guide bar.

C FRAME - These compact, cantilever-type frames are ideal for use where space is limited.

F FRAME - Intermediate-size frame.

Semi-Welded Plate Heat Exchanger

Paul Mueller Company's semi-welded plate heat exchanger is ideal for solution chilling and refrigerant condensing in refrigeration applications.

Semi-Welded applications typically use refrigerant or fluid that is corrosive to gasket materials on the welded side of the heat exchanger. The welded cassettes are designed for optimum gasket sealing. Higher pressures improve the sealing of the gaskets.

The plate pack is built utilizing welding cassettes (two plates welded together). The refrigerant side is contained within the welded portion of the cassette to include welding of the solution port. Gaskets are used to seal the secondary side, which makes the plate pack easy to disassemble and clean.



Brazed Plate Heat Exchanger

Paul Mueller Company offers an extensive range of brazed plate heat exchangers, large and small, to meet your application and the program is constantly being expanded. Many of these units are available in stock and can be shipped the next day in most cases. There is also a network of stocking distributors which can give you immediate access to things you need right away.



MATERIALS OF CONSTRUCTION:

- 304 and 316 Stainless Steel
- Hastelloy®
- Titanium
- Avesta SMO 254®
- Nickel
- Incolo

Features & Benefits



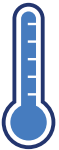
EFFICIENCY

- “U” values of 1,500 and greater are possible
- Accu-Therm plates promote high turbulence at low fluid velocities
- High turbulence results in very high heat transfer coefficients
- **Multiple Duties with a Single Unit:** Heat or cool two or more fluids within the same unit by installing intermediate divider sections
- **More Heat Transfer surface:** Up to 25,000 sq. ft. of heat transfer surface in a single exchanger



LOWER COSTS

- More economical than other types of heat exchangers due to the higher thermal efficiency and lower manufacturing costs



CLOSER APPROACH TEMPERATURES

- Approach temperatures of 2 to 3°F are possible because of the true counterflow and high heat transfer efficiency of the plates



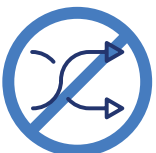
EASE OF CLEANING AND MAINTENANCE

- Simply remove the compression bolts and slide away the moveable end frame to inspect 100% of the Accu-Therm heat transfer surface
- Easy and economical to clean-in-place (CIP)



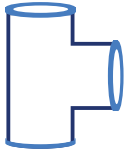
EXPANDABLE

- Adjust the unit's thermal performance by adding or removing plates



CROSS CONTAMINATION ELIMINATED

- Each medium is individually gasketed
- The space between gaskets is vented to atmosphere



CONNECTIONS

- Studded ports are standard and can be fully lined to protect against erosion and corrosion of the frame
- Lap-joint, weld-neck, ferrule, and victaulic connections are also available
- Connections can be mixed and matched to suit individual needs



COMPACT AND LIGHTWEIGHT

- In comparison to shell and tube heat exchangers, PHE's of similar capacity require only $\frac{1}{5}$ to $\frac{1}{2}$ the floor space
- Lighter in total weight than equivalent heat exchangers because of reduced liquid volume and more efficient surface area for a given application



HIGH FLOW RATES

- Flows up to 24,000 gpm
- Port diameters up to 16"



INSPECTION AND TESTING

- Rigorous quality assurance inspections
- Each circuit independently tested at full design pressure
- ASME registration available



REDUCED FOULING

- High turbulence, uniform fluid distribution, smooth plate surface, and high shear stresses reduce fouling



SHROUDS

- Optional OSHA-approved plate pack shrouds are available in attractive and durable embossed aluminum or 2B stainless steel to protect personnel

How to Troubleshoot a Plate Heat Exchanger

Plate Heat Exchangers are an integral part of your system, so when issues arise, it's important to determine whether the problem is a one-time complication or an inherent flaw in your system. Resolving any issue begins with identifying the symptoms of your under-performing heat exchanger. The most common of these symptoms are:

- Increased pressure drop from inlet to outlet
- Loss of heat transfer efficiency
- Loss of flow and performance
- Process fluid leakage

Pressure drop, transfer efficiency, and flow loss typically result from plate fouling while process fluid leakage usually develops from gasket failure. However, gasket failure or the more rare case of plate cracks can lead to any of these symptoms. Taking the simple steps to determine the underlying cause is essential.

Gasket Failure

When troubleshooting PHEs, the easiest problem to identify is gasket failure. When a gasket fails, pressure forces fluid through the leak and it drips out of the PHE from the offending gasket, making it easy to locate. To resolve this issue, disassemble the PHE and remove both the plate with the failed gasket and an adjacent plate (to keep the flow pattern intact). If spare gaskets are available, simply replace the failed gasket, reassemble, tighten your PHE to specification, and put it back in service. If replacement parts are unavailable and downtime is not an option, the PHE can be closed and put back into service until new gaskets arrive. Operating with two fewer plates will only slightly impact performance. It's important to use caution when tightening a PHE with missing plates. Information on safe reassembly can be found in your manual or provided by the manufacturer.

The most common causes of a failed gasket are incompatible fluids and/or excessive pressure. Make sure your pressures are within specifications, your system is free of potential water hammers, and the gaskets are rated for your materials. If gaskets develop holes, your fluid is likely too hot or too corrosive and the gaskets should be replaced with those more suited to your process.

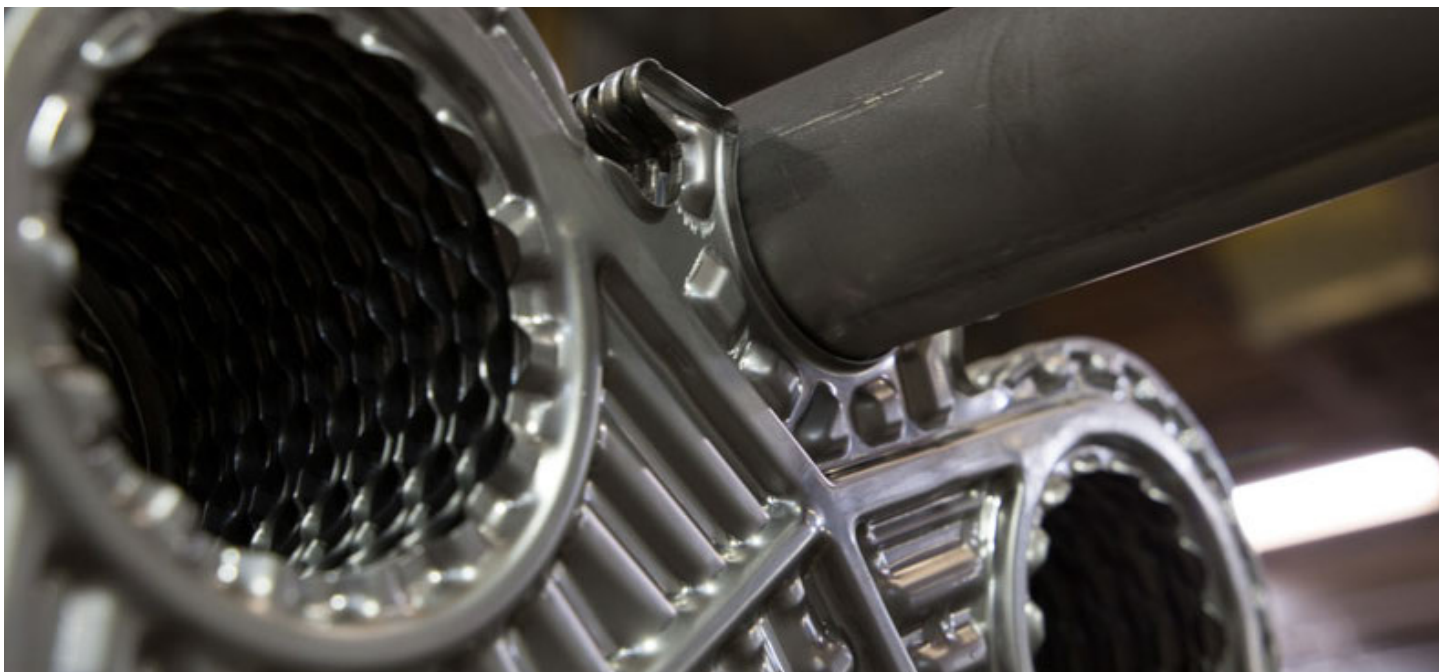
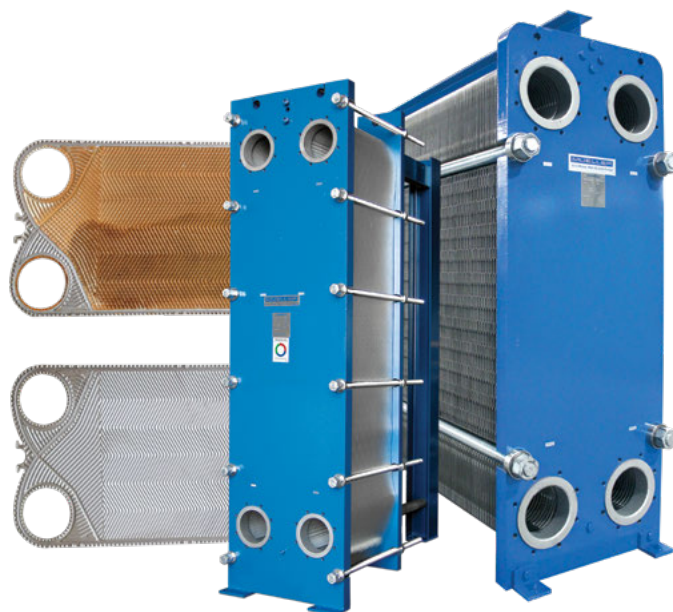


Plate Fouling and Corrosion

Plate fouling is a common issue with PHEs, but is preventable with a proper maintenance and cleaning schedule. Regular visual examinations are important—make sure the plate pack is tightened to specification, the carrying and guide bars are lubricated, and the gaskets are undamaged. Check the pressure gauges to ensure the pressure drop is within the expected limits. The best option for preventing plate fouling is cleaning your PHE regularly either through a clean-in-place (CIP) process or disassembly and manual cleaning. A CIP process involves draining both sides of the PHE and flushing them with water or a compatible cleaning agent to remove debris or build-up. In some cases, manual cleaning of the PHE may be required. Manual cleaning of plates can be done without removing them from the frame. Cleaning agents, a high pressure washer, and a soft bristle brush are recommended for proper manual cleaning of plates.

Routine cleaning and maintenance of your PHE are excellent preventative practices to avoid plate fouling or other issues that cause equipment to fail. For more information or questions regarding maintenance habits, contact one of our representatives at Paul Mueller Company.



Delivery of your PHE

Mueller Transportation Inc., a subsidiary of Paul Mueller Company, has the capability to deliver equipment by our own fleet of trucks and experienced drivers.

Seamless Equipment Transportation

Crafting your new equipment is just one piece of the project. Mueller Transportation Inc. provides complete oversight, care, and delivery of your equipment, no matter the shape or size. Safety and on-time delivery are top priorities as we make the transition from our manufacturing floor to your front door.

Hassle Free

Our team of specialized drivers and installers take full responsibility of your equipment through delivery, installation, and beyond. With more than 100 years of combined service and experience in the industry, Mueller Transportation minimizes risk and keeps your project on track.



Services

Heat Transfer Installation

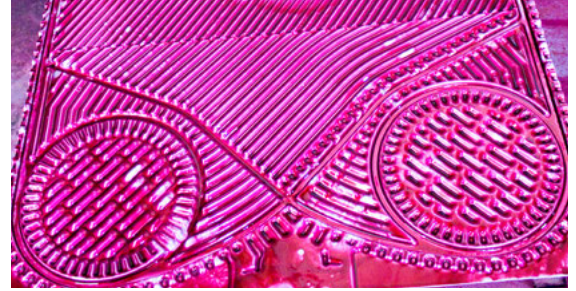
Whether you need a new heat transfer system installed or your existing system modified, our Paul Mueller Company service technicians have the necessary experience to deliver your energy source where you need it most.

Depending on your specific application, we can help you engineer the most efficient heat transfer solution for your equipment and provide installation. With our expertise, we can ensure that your heat transfer system is keeping your process at the right temperatures.



Dye Penetrant Testing

To ensure the reliability and effectiveness of our plate heat exchangers, we utilize dye penetrant testing. This non-destructive method of testing allows for hygienic and thorough detection of potential defects such as leaks, cracks, and pinholes. By detecting these defects early, you can avoid equipment failure, cross-contamination of your products, and ultimately, loss of production time. We offer this service on any manufacturer's plate heat exchanger.



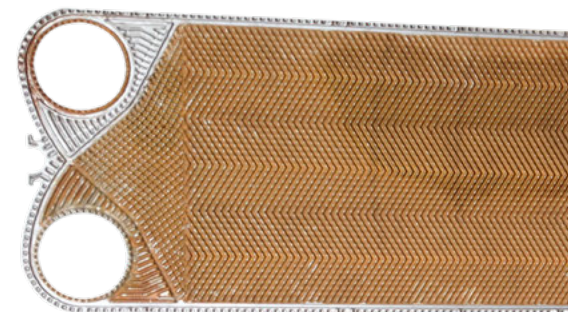
Modifications

As your processing needs change, it may become necessary for modifications to be made to your plate heat exchangers. No matter what heating or cooling requirements you may have, our field service team is fully equipped to make the transition that you need. With our expertise, we can get any manufacturer's heat exchanger functioning exactly the way your process requires.



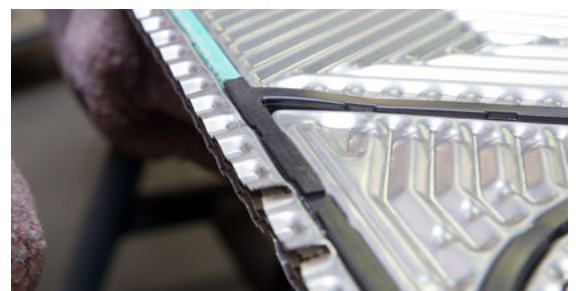
Fouling Removal

When debris and unwanted substances accumulate on the surfaces of your plate heat exchangers and cause fouling, your operational process can rapidly lose efficiency or even halt altogether. Our field service team is equipped with the expertise to quickly and efficiently remove fouling. With proven techniques, we ensure that your downtime is reduced and that your process gets back on track.



Leak Repair

Our expert team of technicians can identify and repair leaks in your plate heat exchangers so your process is back up and running at optimal efficiency.



Consult with Our Experts

THE AMERICAS

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contact@paulmueller.com

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info@paulmueller.com

Netherlands Service
088-683 0010

ASIA PACIFIC

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Unit 601, Empire Tower
26-28 Ham Nghi Street
District 1
Ho Chi Minh City, Vietnam
+84 982 071 506
infomuellerasia@paulmueller.com

Heat Transfer Manufacturing Representative Locator

Nearly 100 Paul Mueller Company representatives across the globe are trained, knowledgeable, and ready to provide a solution to your heat transfer needs.

Our online interactive tool displays our heat transfer representative names, locations, contact information, and directions. To speak to the representative nearest you, visit:

paulmueller.com/heat-transfer-representatives

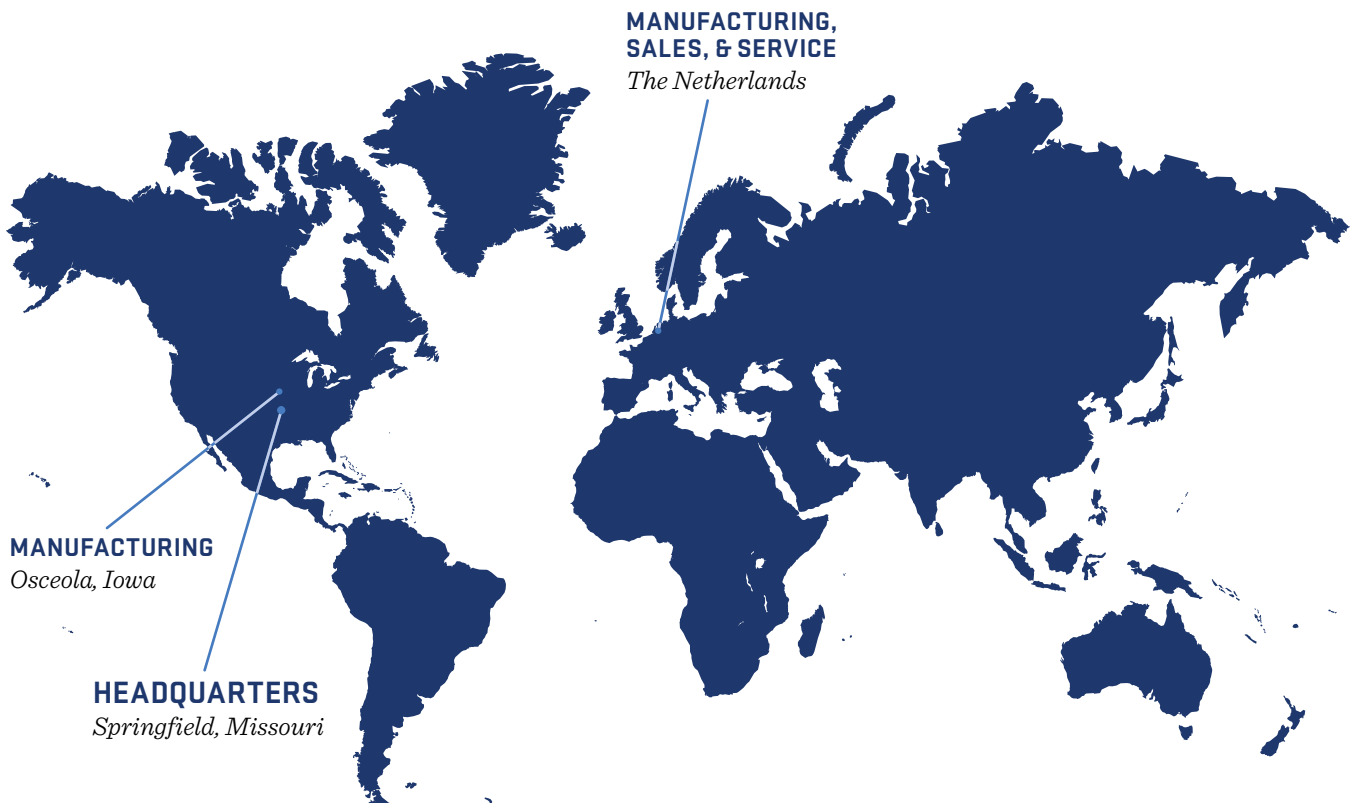


PAUL MUELLER COMPANY



PAUL MUELLER, OUR FOUNDER

At Paul Mueller Company, we are united by a belief that the only quality that matters is quality that works for life. With every piece of processing equipment we build, our goal is to have lasting impact. This collective vision has led us from a small sheet metal shop to a global supplier of heating, cooling, processing, and storage solutions. Our equipment allows engineers, brewers, and food producers to keep operations running as intended. Whether our equipment is used to cool a ship engine or process a refreshing beverage, we are making an impact across the globe.



contact@paulmueller.com

1-800-MUELLER | WWW.PAULMUELLER.COM

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