City of Mesa, Arizona

FOOD TO ENERGY CO-DIGESTION FEASIBILITY STUDY

Anaerobic Digestion Capabilities Concept Memorandum

FINAL

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CONTENTS

APPENDICES

ACRONYMS AND ABBREVIATIONS

AOC	Abnormal Operating Conditions
ASU	Arizona State University
BMP	Biochemical Methane Potential
Cf	Cubic Feet
CH_4	Methane
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_2e	CO_2 emissions equivalents
COD	Chemical Oxygen Demand
CFR	Code of Federal Regulations
DGE	diesel gallon equivalence
DIGs	Anaerobic Digesters
dtpd	Dry tons per day
EPA	Environmental Protection Agency
FOG	Fat, Oil, and Grease
fps	Feet Per Second
GBTs	Gravity Belt Thickeners
GHG	Greenhouse Gas
gpm	gallons per minute
gpd	gallons per day
H_2S	Hydrogen Sulfide
HHV	Higher Heating Value
HP	horsepower
kWh	kilowatt hour
lbs	pounds
mmBtu	One Million British Thermal Units
MT	metric tons
NG	Natural Gas
NH_4-N	Ammonia Nitrogen
NWWRP	Northwest Water Reclamation Plant
OLR	Organic Loading Rate
O&M	Operations and Maintenance
OSW	Organic Solid Waste
PS	Primary Sludge
PSA	Pressure Swing Absorption
psig	pounds per square inch
RIN	Renewable Index Number
RNG	Renewable Natural Gas
SCFH	Standard Cubic Feet per Hour
SCFM	standard Cubic Feet per minute
sCOD	Soluble Chemical Oxygen Demand
SRT	Solids Retention Time
TAS	Thickened Waste Activated Sludge
tCOD	Total Chemical Oxygen Demand
TKN	Total Kjeldahl Nitrogen
TOX	Thermal Oxidizer
tpd	tons per day
TS	Total Solids
TSS	Total Suspended Solids
VS	Volatile Solids
VSS	Volatile Suspended Solids
VSR	Volatile Solids Reduction
WAS	Waste Activated Sludge
wt	wet tons

1 INTRODUCTION

The objective of this Anaerobic Digestion Capabilities Concept Memorandum is to evaluate the feasibility of implementing co-digestion of organic waste feedstock, such as commercial food waste, or organic solid waste (OSW) and/or fats, oils, and grease (FOG), with municipal wastewater sludge at the Northwest Water Reclamation Plant (NWWRP) in Mesa, Arizona. The two anaerobic digesters at NWWRP have excess organic solids loading capacity and therefore have the potential to accept additional organic waste that would otherwise go to landfills. Acceptance of this waste will also increase biogas production which could be used for generating electricity and/or the production of renewable natural gas (RNG). The City of Mesa owns and operates a local natural gas distribution piping network and solid waste collection fleet utilizing CNG trucks, creating a favorable partnership opportunity to pursue this co-digestion project.

In order to evaluate NWWRP's co-digestion capabilities, an interactive Mass and Energy Flow Model (Flow Model) was developed – a tool that dynamically and holistically tracks flows of solids and energy in its various forms throughout the treatment processes. Multiple scenarios were evaluated in the model to determine optimal and operationally friendly loading rates for OSW and FOG and how resulting biogas can be best utilized. The following five sets of scenarios were examined:

Set 1: Co-generation without Mixed HSW organic slurry addition

Set 2: Co-generation with Mixed HSW organic slurry addition

Set 3: RNG Generation with Mixed HSW organic slurry addition

Set 4: Co-generation and RNG Generation with Mixed HSW organic slurry addition

Set 5: Participation in the Low Carbon Fuel Standard (LCFS) Program

The scenarios evaluated examine the optimal amount of mixed HSW organic slurry loading to digesters to conform with operational best practices to limit digester loading rates and deliver pumpable material to NWWRP. Another important variable was examined as to whether just one or both digesters should be accepting imported organic feedstocks, as accepting imported waste in just one digester could preserve partial D3 RIN classification; for further information explaining D3 versus D5 RIN classifications, refer to 'Tech Memo 6 – Biogas Utilization & Project Incentives'. Another variable evaluated was the biogas utilization options of generating electricity with a CHP system or producing RNG via a new biogas upgrading system. The scenarios are evaluated based on annualized savings which includes both annualized capital costs and annual O&M considerations. Also quantified for each scenario is the Scope 2 greenhouse gas (GHG) emission reduction, which gives insight into the optimization of energy use and sustainability benefits of each scenario. The purpose is to both determine the design sizing parameters for the pre-processing facility proposed at the City's Center Street Yard and to identify the most beneficial end use for the biogas produced at NWWRP.

2 EXISTING CONDITIONS

Available plant data, field information obtained from site visits, and discussions with plant operational staff were used to quantify parameters of existing solids and energy processes. The processes considered are those included in the Flow Model, which starts at the solids generating processes (primary and secondary clarifiers) and traces the solids and energy flows to final end use of biosolids and biogas. Liquid process stream attributes of the plant and energy usages due to pumping are not incorporated into this analysis, however nutrient recycling loads from side streams was considered. The following sections provide a summary of the existing processes and corresponding input parameters to the Flow Model.

2.1 Primary and Waste Activated Sludge

Primary sludge (PS) is pumped from the primary clarifiers and the waste activated sludge (WAS) is pumped from the secondary clarifiers into a blend tank, located in the Solids Handling Building. The Plant previously operated both a PS wet well and an WAS wet well in parallel. However, due to the volume of sludge flows, the WAS storage tank was found to have sufficient blending volume for all sludge flows and the PS storage tank was taken out of regular use.

Daily and monthly flow data for both PS and WAS were provided by Plant staff, as well combined flow of PS and WAS into the blend tank. Daily and monthly data was provided on the % Total Solids (TS), TS loading, % Volatile Solids (VS), and VS loading for the combined PS and WAS flow into the Blend Tank. From these values, average solids loading of PS and WAS were generated as shown in Table 1.

Table 1. Average Primary Sludge and Waste Activate Sludge Parameters

Parameter	Primary Sludge (PS)	Waste Activated Sludge (WAS)	Unit
Flow	260,900	112,100	gallons/day
Total solids	1.0%	0.8%	%
Total Solids	21,400	7,200	lbs/day
Volatile Solids	79%	79%	%
Volatile Solids	17,000	5,700	lbs/day

2.2 Sludge Thickening

The Plant typically operates one centrifuge continuously, seven days per week. The design hydraulic loading of each centrifuge is 500 gpm and NWWRP staff stated that the centrifuges are currently running at half capacity. The centrifuge thickened sludge is discharged to a thickened sludge well below and then pumped by progressive cavity thickened sludge pumps to the digesters via the sludge heating and recirculation line. Table 2 shows the estimated sludge parameters in and out of the thickening centrifuges. The TS feed to the two digesters occur in alternating batch operations where 600 gallons are pumped to one of the two digesters then valving alternates and 600 gallons are pumped to the other digester. The alternating digester feeding process is continuous.

At times, the TS batch feed is increased to 1,000 gallons to coincide with Caterpillar generator peak-shaving operations (Genset Operations) so as to produce additional biogas and extend the biogas runtime to about 5 hours before Genset operations are switched to natural gas fuel for the remainder of the 12-hour peak-shaving period. The sludge loads as summarized in Table 1 and Table 2 were used as the primary inputs to the Solids and Energy Flow Model.

Table 2. Blended Sludge and Thickened Sludge Parameters

Parameter	Unthickened Blend Sludge	Thickened Blended Sludge	Unit
Average Flow	373,000	69,600	gallons/day
Total Solids	0.9%	4.9%	%
Total Solids	28,600	28,600	lbs/day
Volatile Solids	79%	79%	%
Volatile Solids	22,700	22,700	lbs/day

2.3 Anaerobic Digestion

NWWRP operates two active primary egg-shaped digesters. Both digesters have a capacity of 875,000 gallons (116,979 cf). The primary digesters are fed relatively equal mixes of sludge types on a time-based feeding operation. The existing NWWRP egg-shaped digester shape improves mixing efficiency and promotes the resuspension and removal of grit and other heavy materials. The existing draft-tube mixing system is a positive means of mixing the surface of the digester controlling scum and foaming, thereby ensuring a more homogeneous biosolid product. Philadelphia Mixing Solutions, the existing draft tube manufacturer, has confirmed that the existing draft tube mixing would provide sufficient mixing for the estimated Co-Digestion operations with the addition of Mixed HSW at the following parameters: 42,000 gpd flow, 6.2% TS and 400 cP viscosity at 98^{o}F.

The digesters have a recirculation heating system through which sludge is drawn through four centrifugal sludge heating recycle pumps (two standby) and three tube-in-tube sludge heat exchangers (one standby), heated by a hot water loop and pumped back to the digesters. The recycle pumps have a rated capacity of 250 gpm each. The sludge heat exchangers are rated for a sludge flowrate of 150 gpm each. The heating supply comes from a plant hot water loop that is heated by a set of boilers. Plant staff report that these boilers are exclusively fired off natural gas Table 3 and Table 4 summarize the digestion loading and performance parameters determined from provided plant data. The Solids and Energy Flow Model was calibrated to align digester parameters and outputs to the data summarized in Table 3 and Table 4.

Table 3. Digester Loading Parameters

Parameter	Digester 1	Digester 2	Total	Unit
Average Flow	35,240	34,330	69,570	gallons/day
Total Solids	4.9%	4.9%	4.9%	%
Total Solids	14,510	14,130	28,640	lbs/day
Volatile Solids	79%	79%	79%	%
Volatile Solids	11,500	11,200	22,700	lbs/day

Table 4. Digester Performance Parameters

Parameter	Digester 1	Digester 2	Total	Unit
Solids Retention Time	24.8	25.5	25.2	Days
Volatile Solids Reduction (VSR)	7,030	6,850	13,880	pounds/day
% Volatile Solids Reduction	61%	61%	61%	%
Gas Yield	13.7	13.7	13.7	Cf/ lb VSR
Organic Loading Rate	0.10	0.10	0.10	lb VS/cf/day
Biogas Produced	66.9	65.2	132.1	Scfm
Biogas HHV	616	616	616	Btu/cf
Biogas Energy Production	2.47	2.41	4.88	mmBtu/hr

NWWRP's digester parameters as derived from plant data appear to be within the typical targets or typically expected ranges, indicating that data derived values can be considered accurate. The VSR value of 61% is somewhat higher than the typical value of 45-55%, however, NWWRP digests approximately 3 times more PS than WAS on a mass loading basis, which would increase the expected %VSR. The digester parameter of Gas Yield aligns with the literature value range of 12 to 18 ft^3/lb of volatile solids destroyed, which also suggests accuracy in the biogas metering and VSR data.

2.4 Sludge Dewatering

Digested sludge is sent to the digested sludge well, located in the Digester Control Building. The digested sludge is then sent from the digested sludge wet well through grinders and pumped to the centrifuges digested sludge pumps which are capable of handling 3% - 4% TS, as confirmed by the Plant Staff.

The dewatering centrifuges are located on the upper level of the Solids Handling Building. There are two dewatering centrifuges with one unit typically in service (one standby). The system is designed to run one centrifuge at a continuous hydraulic loading rate of 150 gpm. According to available hourly flow data, the dewatering centrifuges appear to operate for 8 hrs/day for 5 days/week and sends the dewatering centrate into the sewer directed toward the 91st Avenue WRP. A polymer dosing rate of approx. 5.8 gallons per dry ton was provided by NWWRP staff.

Table 5 and Table 6 present the current dewatering loading and performance parameters developed from the data and calibrated for alignment in the Solids and Energy Flow Model. The Flow Model is utilized to predict dewatering loads and associated discharge cake as well as energy and polymer consumption as a function of the digester output performance.

Table 5. Current Dewatering Loading Parameters

Parameter	Digested Sludge	Unit
Average Flow	69,570	gallons/day
Total Solids	2.7%	%
Total Solids	15,830	lbs/day
Volatile Solids	65%	%
Volatile Solids	10,240	lbs/day

Table 6. Current Dewatering Operations and Performance Parameters

Parameter	Dewatering Centrifuges	Unit
Operation Hours per Week	8 hrs/day, 5 days/week (40 hours/week)	
Typical Units in Service	1	
Estimated Hydraulic Loading per Unit	48	gallon/minute
Design Hydraulic Loading per Unit	150	gallon/minute
Design Power Draw per Loading	250	HP/ gallon/minute
Estimated Total Power Draw	80	HP
Polymer Dose	5.83	gallon/dry ton
Polymer Cost	$ 7.96	$/gallon
Annual Polymer Cost	$ 96,200	$/year

2.5 Final Solids Outlet

The dewatered digested sludge, or biosolids cake, is deposited into two cake storage hoppers located directly below the centrifuges in the Solids Handling Building. The hopper then deposits the biosolids directly into hauling trucks in an enclosed and odor controlled loading bay on the first floor of the Solids Handling Building.

NWWRP currently uses a contract hauler to deliver the dewatered sludge cake to a privately-owned landfill. Biosolids are offloaded 5 days per week. On average, NWWRP pays their contract hauler $14.25 per wet ton for disposal to a landfill as daily cover, making the final solids outlet relatively cost effective.

Final solids disposal data for wet mass hauled and contracted cost provided by NWWRP staff was used as a final check to ensure that the Solids and Flow Model was calibrated to current conditions. Final mass hauled from the plant is typically the most accurate and cost sensitive data being recorded for solids management programs. Table 7 compares the recorded NWWRP hauled loads and cost to the same baseline values generated through the Flow Model.

Table 7. Final Biosolids Disposal Parameters

Parameter	2017 - 2018 Solids Outlet NWWRP Data	Flow Model Values Dewatered Biosolids	Unit
Wet Solids	59,380	59,520	lbs/day
Total Solids	21.8%	21.8%	%
Total Solids	12,950	12,980	lbs/day
Volatile Solids	65%	65%	%
Volatile Solids	8,380	8,400	lbs/day

Due to the relatively affordable biosolids disposal costs, it is not recommended that the City of Mesa investigate the feasibility and benefits of more advanced biosolids treatment, such as generating Class A biosolids.

2.6 Biogas Utilization

Biogas is collected from a gas dome at the top of each digester and piped to the lower level of the Digester Control Building where gas is sent through two foam separators, one dedicated to each digester. The biogas lines are then joined into one 10-inch header and sent below grade to the gas compressor room attached to the Solids Handling Building.

In the gas compressor room, NWWRP currently operates a gas conditioning system consisting of a compressor and a dryer for moisture removal. As reported by Plant Staff, the liquid ring compressor is sized for 220 cfm and operates at its upper pressure limit of 80 psig which then feeds the downstream gas dryer designed for the same pressure. There is a recirculation loop with a globe valve located in the compressor room that allows compressed and dried biogas discharge to be recycled back to the compressor suction to allow for enhanced control of biogas flow rates through the compressor. The compressor suction pressure increases as the gas pressure downstream (in storage tank) increases which requires adjustment of the recirculation globe valve to compensate. The compressor will shut down if the compressor suction pressure drops to 4.5" W.C. and trigger a low suction pressure alarm. After treatment via the gas conditioning system, the pressurized biogas is fed either directly to the cogeneration engine or to a pressurized digester gas storage tank.

The existing single engine unit is a Caterpillar G3512E, which operates on biogas or natural gas (but not a blend) at 1.5 psig. Currently, biogas directly from the digester is supplemented with biogas from the storage tank or natural gas to peak shave electrical utilization during peak daytime hours. Normal engine operation takes place between 11am – 11pm during Summer and Summer – Peak seasons, and 5am – 9 am & 5pm – 9pm during the Winter season. During these peak periods, there are additional price increases during daily 'On-Peak' periods as compared to 'Shoulder-Peak' periods.

Table 8 shows the comparison of costs associated with electrical power costs during seasonal and daily periods.

Table 8. 2018 Costs Associated with Electrical Power Costs

Season	Off-Peak		Shoulder-Peak		On-Peak	
	hrs/day	$/kWh	hrs/day	$/kWh	hrs/day	$/kWh
Summer - Daily [May - Jun, Sep - Oct]	12	$ 0.0439	6	$ 0.1012	6	$ 0.1076
Summer - Peak [Jul - Aug]	12	$ 0.0504	6	$ 0.1063	6	$ 0.1425
Winter [Nov - Apr]	16	$ 0.0405	4	$ 0.0779	4	$ 0.0783

The engine is fed biogas at a rate of 132 scfm directly from the digesters and supplemented with approximately 11 scfm from the digester gas storage tank. As reported by Plant Staff, the engine currently generates 525 kW of electricity when running which is approximately 87.5% of its rated capacity of 600 kW. Based on the fuelling rate of 143 scfm of biogas at 616 Btu/cf HHV producing 525 kW, the engine is estimated to be operating at 23% electrical efficiency, which is below the typical electrical efficiency for a modern cogeneration engine. Engine electrical efficiencies will vary significantly based on size and model type, but engines sized in the 500 to 1,000 kW range are typically 33% to 38% efficient when operating at full rated loads.

The biogas storage tank is currently utilized at the liquid ring compressor's maximum discharge pressure of 80 psig. Once the storage tank is depleted (which takes approximately five hours under current operations) the engine is switched over to natural gas for about 3 hours as the storage tank is refilled, then switched back over to biogas for the remainder of the peak period. Additional biogas produced during the time in which the engine is operating on natural gas beyond the storage tank capacity, or when the engine is not in operation, is sent directly to the waste gas burner.

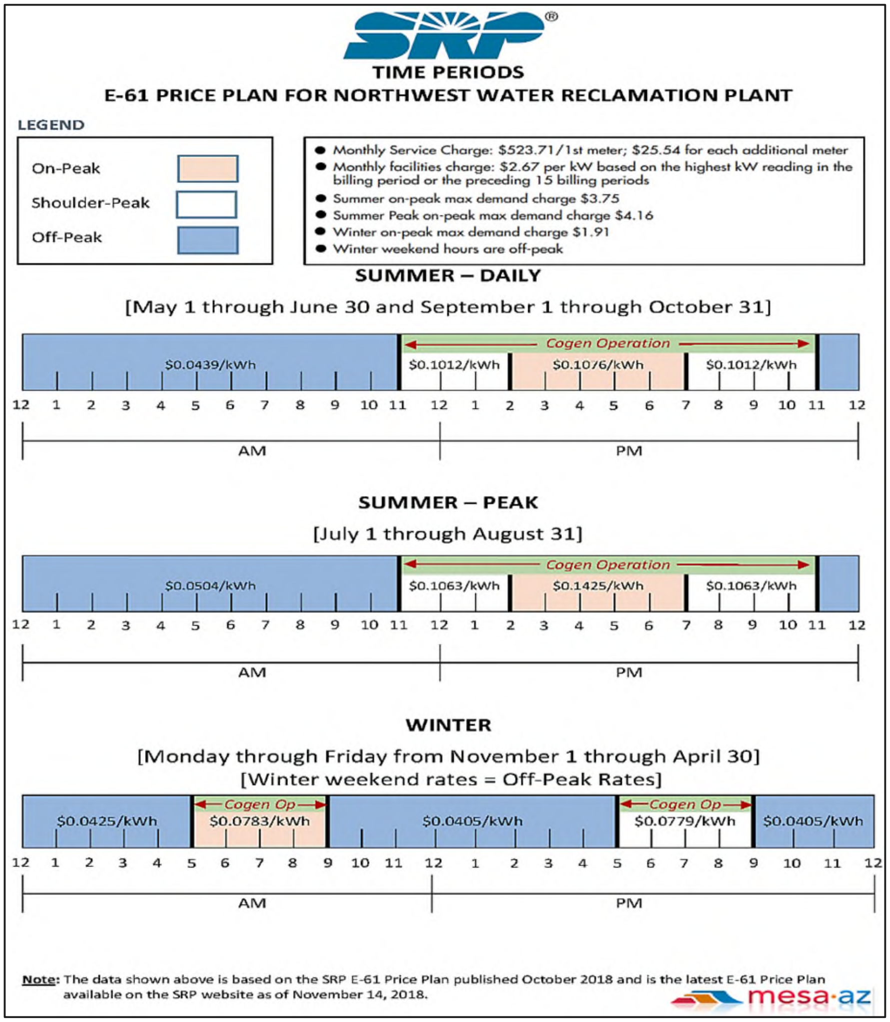


Figure 1. 2018 Price Plan from NWWRP (the City of Mesa)

Average daily gas flows data to the engine are shown in Figure 2 below. From the Nov 2017 to Nov 2018 daily biogas flow data provided, the engine was in operation for 210 days of the year and was in service on average for 10 hours per day. This makes the engine operations approximately 23% uptime or availability. A portion of the engine downtime is intentional due seasonal periods (winter) with relatively low electrical power cost from the utility when the engine is taken offline, with additional general downtime for engine and biogas systems maintenance requirements.

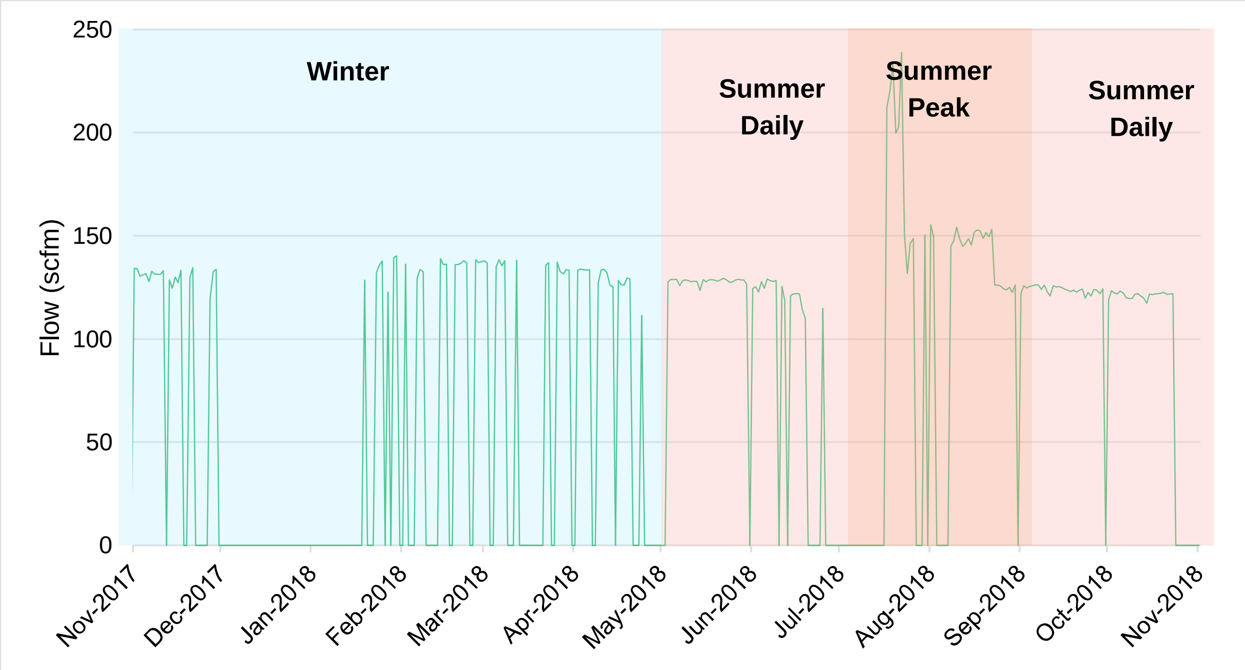


Figure 2. 2018 Seasonal and Daily Costs Associated with Electrical Power Costs

The excess biogas is sent directly to an enclosed flare onsite. The existing enclosed Callidus Technologies Inc. flare was installed in 2000 and is rated to approximately 30,000 scfh of biogas. While evaluating the existing flare's design capacity to under co-digestion conditions it was determined that the flare is significantly aged and NWWRP has no redundancy for digester gas disposal should the existing flare fail.

Additionally, at the current production rate of 132 scfm, or 7,920 scfh, the existing flare is sized for flows nearly 4 times larger than the current biogas flows at NWWRP, likely meaning biogas is incompletely combusted when flared. Even under co-digestion conditions the projected average biogas flow is 18,000 scfh. Therefore, it is recommended that NWWRP replace the current flare system with a new flare system sized to the projected average biogas generation rates.

2.7 Mesa Sanitation CNG Fleet

Compressed Natural Gas (CNG) Fleet – As of 2019, the City of Mesa's compressed natural gas (CNG) fleet has 46 vehicles and is expected to reach 74 vehicles in the next 3 years. From November 2017 to October 2018, Mesa consumed over 625,400 diesel gallon equivalence (DGE) per year (1,710 per day); equating to about $281,800 in fuel charges.

3 ASU DIGESTER BENCH TESTING

The Biodesign Swette Center for Environmental Biotechnology (BSCEB) at Arizona State University (ASU) conducted a bench study to evaluate the potential impact of food waste and FOG addition on anaerobic digestion. ASU evaluated the potential benefits and risks of co-digesting by operating six 2-litre reactors anaerobic digesters inoculated with NWWRP thickened sludge.

Additionally, the City of Mesa performed an OSW Collection Pilot and a Food Audit of local pre-consumer and commercial OSW producers in the area. Under the OSW Collection Pilot, samples of OSW were collected from five vendors of various industry types as shown in Table X. In January 2019, ASU began receiving OSW from City of Mesa, FOG from City of Tempe, and OSW from ASU's cafeterias. Comprehensive sampling of the OSW and FOG were performed as an integral part of research and understand the available OSW in the greater Mesa area.

3.1 Control Bench Digesters

The baseline conditions, or 'control', was developed by ASU by testing the characteristics of the reactors when loaded with thickened sludge directly supplied by NWWRP. All reactors were seeded with thickened sludge and operated at baseline conditions for 2 months to ensure the digesters achieved stability. Testing of the reactors began on October 29th, 2018.

Table 9 presents the ASU reported values thickened sludge characteristics. Table 10 and Table 11 below, compare the ASU reported values to the NWWRP reported values.

Table 9. Bench Thickened Sludge Characteristics

Parameter	Thickened Sludge Feed to Bench Reactors	Unit
Total Suspended Solids (TSS)	46	g SS/L
Volatile Suspended Solids (VSS)	41	g SS/L
TSS/VSS	81.4 %	%
Total Chemical Oxygen Demand (tCOD)	57.8	g COD/L
Soluble Chemical Oxygen Demand (sCOD)	2.6	g COD/L
Alkalinity	880	mg $CaCO_3$/L
Ammonium	149	mg NH_4-N/L
pH	6.2	
Total Kjeldahl Nitrogen (TKN)	2.6	mg N/L

Table 10. Control Bench Digestion Characteristics (Thickened Sludge-Only)

Parameter	ASU Control Bench Reactor	NWWRP Operational Data (For Reference)	Unit
Total Suspended Solids (TSS)	28	19[1]	g SS/L
Volatile Suspended Solids (VSS)	19	13[1]	g SS/L
TSS/VSS	67%	79%	%
Total Chemical Oxygen Demand (tCOD)	30.4	-	g COD/L
Soluble Chemical Oxygen Demand (sCOD)	1.5	-	g COD/L
Alkalinity	4,410	-	mg $CaCO_3$/L
Ammonium	863	549	mg NH_4-N/L
pH	7.4	7.4	
Total Kjeldahl Nitrogen (TKN)	1,700	-	mg N/L
Biogas HHV	568	616	Btu/cf

1. Total dissolved solids assumed to be negligible

Table 11. Control Bench Digestion Parameters (Thickened Sludge-Only)

Digestion Parameters	ASU Control Bench Reactor	NWWRP Operational Data (For Reference)	Unit
Solids Residence Time	25.9	24.8	Days
% Volatile Solids Reduction	48%	61%	%
Gas Yield (cf/lb VSR)	21.1	13.7	cf/lb VSR
Organic Loading Rate	0.09	0.10	lb VS/cf/day

In general, the ASU control reactor accurately represented the NWWRP digesters. The reactor size, thickened sludge feeding frequency, and the reactor mixing is most likely the reason for the disparity between the NWWRP digesters and the ASU reactor(s)the VSR and gas yield.

3.2 OSW and FOG Characterization

Samples of pre-consumer and commercial food waste, or organic solid waste (OSW), were collected from five vendors of various industry types for an OSW collection pilot by the City of Mesa and a bench digestion test performed by Arizona State University (ASU). These samples were analyzed for various characteristics. Descriptions of the OSW generators and result of preliminary feedstock analysis available to date are summarized in Table 12 and Table 13 below.

Table 12. OSW Collection Pilot Testing Vendor and Waste Details

Vendor	Industry Type	Waste Characterization	Observed Contamination
Bashas’	Grocery	Bakery, Deli (meats, sandwiches, sides), Produce (vegetables)	Rigid plastic food containers, cartons,
EVIT	Cafeteria & Restaurant Kitchens	Produce (vegetables)	Film plastics, Flexible plastic beverage containers
United Food Bank	Food Bank	Packaged foods (meat, canned vegetables, baked goods), Produce (fruits & vegetables)	Metal cans, Rigid and flexible plastic containers, Cartons, Film plastics
Mesa Public School	Cafeteria Kitchen	Prepared meals (meat, carbohydrates, produce)	Food wrappings, Flexible plastic beverage containers
Tempe FOG Collective	Grease Interceptor Waste	Fats, Oil, Grease, White water	Sediment, utensils

Table 13. Organic Solid Waste & FOG Characteristics

Food Waste Characteristics	Food Waste ASU Bench Test Values	FOG ASU Bench Test Values	Unit
Total Solids	23%	3.8%	%
Moisture	77%	96.2%	%
VSS/TSS	93.5%	88.5%	%
Total Chemical Oxygen Demand (tCOD)	59.0	13.1	g COD/L
Soluble Chemical Oxygen Demand (sCOD)	208.1	166.4	g COD/L
pH	4.28	4.48	
Protein [Lowry Method]	45%	28%	%
Fats/Lipids	12%	60%	%
Carbohydrates	48%	3%	%

The characteristics, as presented in Table 13, were used to determine the flows and characteristics of mixed HSW organic slurry transferred from the pre-processing facility to NWWRP. Compared to sludge, OSW has a higher percentage of readily degradable solids that may vary based on the specific load.

The reported lipids and carbohydrates percentages are within the expected ranges for commercial food waste and FOG. However, the protein percentages are considerably above the typical ranges. Industry standards for similar food waste streams, such as pre-consumer and commercial kitchens, are reported to have between 15-25% proteins (as % of VS). Therefore, a reading of 48% protein is 2 to 3 times higher than the typical range. FOG is typically 0% proteins (as % of VS); therefore, 28% proteins is not considered to be representative of the average protein content that will be encountered in imported FOG streams.

Biogas production is directly related to the volatile solids destroyed by anaerobic biochemical reactions. Typical biogas yields vary between types of waste being digested, as shown in Table 14. The OSW biogas yield was estimated as 16 cf/lb VS destroyed from available literature values and experience with the typical waste types being targeted for diversion to the digesters. This value will be updated when bench test data becomes available.

Chemical Oxygen Demand (COD) concentration is another parameter typically used for determining the amount of readily degradable organic material within potential digester feedstocks. COD will also be used as a parameter to project and verify biogas production from various feedstocks as the data becomes from bench testing.

FOG is an energy-rich substance which is highly degradable in an anaerobic digester. The benefits of FOG addition on volatile solids reduction (VSR) and biogas yield are well documented. It is assumed that 95% of FOG VS are readily degradable from reported literature values and experience with the unit processes. Gas yield from FOG was assumed to be 20 cf/lb VS destroyed. These values will be updated when bench test data becomes available.

Table 14. Manual of Practice 8 Biogas Production Rates from Various Organic Materials (MOP8, 2017)

Material	Gas Production per unit mass Destroyed Cf/lb VS destroyed
Typical Sludge	13 – 18
Fats/Lipids	20 – 25
Grease	17
Proteins and Carbohydrates	12

Samples of commercial food waste were collected from five vendors of various industry types for an OSW collection pilot by the City of Mesa and a bench digestion test performed by Arizona State University (ASU). Information related to the five vendors and TS percentages for their associated OSW are summarized in Table 15 below. ASU began receiving food waste on January 14, 2019 from the Mesa bench food waste temporary pre-processing at Center Street Hazardous Household Materials (HHM) Facility.

Table 15. City of Mesa Food Waste Audit Results

OSW Source	Type of Source	Total Solids (%)
Trader Joe's	Grocery Store	27.8%
Safeway	Grocery Store	32.5%
Whole Grain Bread Co.	Bakery	57.9%
Organ Pipe Pizza	Restaurant	53.6%
United Food Bank	Food Bank	32.1%
Average		40.8%

Under a full-scale OSW receiving and processing program, it is expected that the characteristics, as shown above, will be representative of the processed HSW. It is planned that following the collection of the waste from generators, the OSW and FOG will be decontaminated and processed into a mixed HSW organic slurry at a separate facility proposed at Center Street Yard. Specific details regarding the proposed site, facility layout, and equipment will be presented separately in the 'Pre-Processing Facility Concept Memorandum'. Therefore, it can be assumed that the mixed HSW slurry delivered to NWWRP contains negligible contamination.

3.3 Co-Digestion Bench Test Results

ASU introduced food waste into Bench Reactors B - E on January 11, 2019. On January 18, 2019 the food waste loading was ramped on a flow rate basis to 100% and 150% of the thickened sludge flow rate into the reactors. ASU also introduced FOG on January 18, 2019 and ramped up loading on a flow rate basis to 5% and 20% of ‘food waste + thickened sludge’ flow rate as of January 23.

Anaerobic digesters would ideally be fed at a consistent and constant rate to provide optimal conditions for microorganisms to thrive and minimize the potential for upsets from shock loading. To prevent shocking the reactors, ASU began adding small volumes of OSW to reactors on January 11 and FOG on January 21. Reactor feed rates were incrementally increased the until the reactors reached the full target feed rate as shown in Table 16.

At the full target feed rates, all experimental reactors fed and sample (gas & effluent liquid) taken on Mondays, Wednesdays, and Fridays. The ‘control’ reactor feed rates were not altered. Additional gas analysis on Saturday or Sunday was conducted as needed to prevent overfill.

Following discussions between ASU and Arcadis, it was decided that the OSW and FOG slurry fed to the digesters should be adjusted to 10 - 12% TS target to better match the intended full-scale operating conditions. The characteristics and calculated parameters of ‘the Target Loading’ Reactor are shown below in Table 17.

Table 16. ASU Reactor Operating Conditions

Reactor	Volumetric Feed Ratios			HRT (day)
	Thickened Sludge	OSW (at 12% TS)	FOG	
Baseline (Control)	1.0	0.0	0.0	25.9
Target Loading 1*	1.0	0.3	0.0	20.0
Target Loading 2*	1.0	0.3	0.0	20.0
Higher FW Loading	1.0	0.4	0.0	18.5
Lower FOG Loading	1.0	0.12	0.5	15.5

* Considered most representative of full-scale application operating conditions

Table 17. "Target Loading 1" Reactor Comparison to the Control Reactor

Parameter	Control Reactor	Target Loading 1 Reactor "LS-FW"	Unit
Organic Loading Rate	0.097	0.143	lb VS/cf/day
VS / TS Ratio	67%	73%	%
Soluble COD	1,562	3,676	mg COD/L
Total COD	30,930	35,889	mg COD/L
Ammonium Nitrogen	1,009	1,090	mg NH_4-N/L
Total Kjeldahl Nitrogen	7.9	7.9	mg TKN/L
Orthophosphate	530	590	mg PO_4/L
Total Phosphorus (TP)	600	690	mg PO_4/L
pH	7.4	7.4	
Alkalinity	4,582	4,728	mg/L
Volatile Solids Reduction	49.0%	50.4%	% VS
Biogas Yield	18.5	26.0	cf/lb VS destroyed day
Energy Content	535	565	BTU/cf

In general, the ASU target reactor accurately represented the expected changes in digested performance. The disparity between the NWWRP digesters and the ASU reactor 'control' VSR and gas yield in the reactors. However, the trends accurately represent the expectations for co-digestion. Specifically, the biogas yields, while the 18.5 cf/lb VS destroyed is significantly higher than the NWWRP is currently reporting. A significant increase in gas is expected due high percentage of grease, fats, and lipids.

Additionally, the VSR is expected because the OSW and FOG is expected to have high percentages of readily degradable volatile solids. The expected VSR and biogas yields are presented available in the Model Scenarios.

4 PROPOSED OPERATIONS

The following section introduces the new processes that could potentially be implemented at NWWRP to accept imported organic waste and enhance biogas utilization. These new processes are described including integration strategies into existing plant operations.

4.1 Primary and Waste Activated Sludge

Under the proposed operations, there are no significant changes to the primary sludge (PS) processing or waste activated sludge (WAS) collection systems. The following section introduces a new process that could potentially be implemented at NWWRP to improve WAS degradability. Performance parameters, O&M and estimated capital costs for implementation are also provided in this section. These new processes can be activated as part of the Solids and Energy Flow Model to evaluate various scenarios for energy recovery.

WAS Lysis

WAS Lysis is a process that can be used to rupture cell walls within the biological WAS, thereby increasing digestibility of this material and allowing better viscosity at higher concentrations. This drives a variety of benefits including increased digester SRT, reduced digester heating loads, more biogas generation, less hydraulic and mass loading to dewatering, and less wet mass for final disposal. The WAS lysis system examined was the Pondus system. This uses caustic soda addition to bring sludge flows up to pH 11 and low-grade heating to 150ºF to break down the cell membranes of WAS. When WAS cells are ruptured, internal acids are released returning the sludge flow to near neutral pH. Mixing of heated WAS back with cold primary sludge provides an essentially heating neutral operations compared to traditional mesophilic digester heating.

The major consideration for implementation of Pondus at NWWRP is that is requires a separate WAS flow that is separately thickened and then heated and lyzed. Currently PS and WAS are blended in a single tank and thickened in a single centrifuge. Introduction of Pondus would require utilizing the separate existing PS and WAS wells as originally intended and operating two separate thickening centrifuges. Since the plant currently has two centrifuges, a third unit may need to be added for redundancy. Table 18 gives the parameters for Pondus incorporated into the Solids and Energy Flow Model.

Table 18. Pondus System Parameters for Flow Model

Parameter	Model Value	Unit
Thickened WAS flow rate to Pondus	23,760	gpd
Thickened WAS % TS to Pondus	6%	%
Thickened WAS Mass Loading	7,220	lbs/day
Increase in Thickened WAS Digestibility	35% - 68%	%

50% NaOH Consumption	35.7	gpd
Estimated NaOH Cost	$1.80	$/gallon
Capital Cost	$3,360,000	USD

4.2 Mixed HSW Organic Slurry Equalization and Injection

Mixed HSW organic slurry Offloading and Equalization Design. The slurry will be transferred from the pre-processing facility to NWWRP via tanker truck, with vehicles designed to transfer and pump liquified loads in a sealed containment vessel to minimize the risk of spills and odor. It is recommended that a target of 12% - 15% total solids (%TS) for mixed HSW organic slurry be delivered to NWWRP to both ensure pumpability and minimize hauling loads between facilities. Therefore, depending on the daily waste characteristics arriving at the pre-processing facility, dilution water may need to be added to the slurry in order to reach the appropriate %TS. Details regarding the dilution requirements prior to NWWRP are summarized separately in the 'Pre-Processing Facility Concept Memorandum'.

The mixed HSW organic slurry from the tanker truck will be offloaded into a holding tank at NWWRP for equalization prior to injection. The proposed approach is to utilize the currently unused 50,000-gallon primary sludge (PS) wet well located in the Solids Handling Building. Utilizing this existing tank minimizes the capital costs of the project and provides an equalization tank located near the Solids Handling Building loading bay which is ventilated and provides adequate odor control for the OSW offloading station.

Figure 3 and Figure 4 show the recommended arrangement for mixed HSW organic slurry receiving, equalization and injection into the digesters by reutilizing the existing PS wet well as a repurposed mixed HSW organic slurry equalization tank.

Mixed HSW organic slurry Injection System Design. Under this project, new dilution capabilities will be included in the upgrades to the PS wet well tank being repurposed as a mixed HSW equalization tank. The mixed HSW organic slurry handling system will accommodate the 10-15% total solids slurry at a continuous feeding rate. The mixed HSW organic slurry equalization tank shall be equipped with the option to dilute the slurry with WAS, or plant effluent, if needed.

The tank will also be equipped with a set of recirculation/mixing pumps with grinders attached to keep the solids in suspension in the upgraded slurry equalization tank to avoid excessive sedimentation within the tank.

There are currently two alternatives for mixed HSW organic slurry injection at NWWRP.

The first alternative is to inject the slurry directly from the HSW equalization tank into the digesters. The HSW equalization tank will be equipped with another smaller set of feed pumps to the digester. The mixed HSW organic slurry digester feed pumps will be designed specifically for the slurry at 10-15% TS. If NWWRP elects to accept the maximum slurry flows, the constant feed rate will be approximately 10 gallons per minute (gpm) on a 24 hours/day basis, or 30 gpm for a constant feed during daily business hours (8-hour day). At this flow condition the constant feed rate will be accomplished with a small, positive displacement digester feed pump. Capital and operation expenses associated with reutilizing the PS wet well are presented in Table 19.

The second alternative injects the slurry into the adjacent thickened sludge wet well, at a similar feed rate. The existing thickened sludge wet well pumps would continue to be used to pump the mixed sludge and HSW streams into the digesters.

Table 19. HSW Offloading, Receiving, and Equalization Parameters

Parameter	Model Value	Unit
Capital Cost	$476,000	USD
Annual O&M Cost	$5,000	$/year
Power Draw	15	kW

It is recommended that NWWRP retrofit the existing Primary Sludge Wet Well for mixed slurry equalization and continuously pump the HSW slurry into the Thickened Sludge Wet Well, as is shown below in Figure 3 and Figure 4.

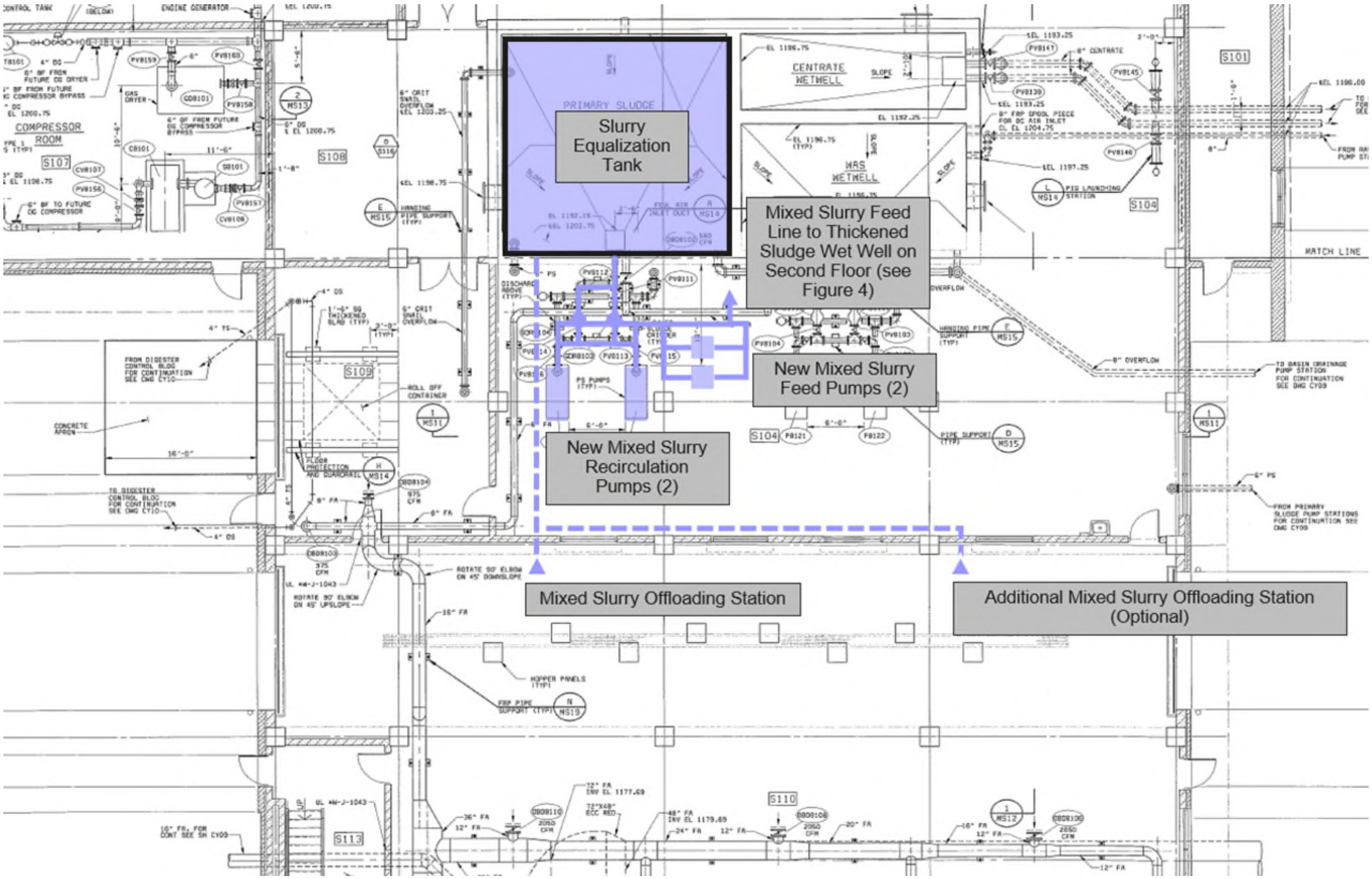


Figure 3. Direct Equalization Tank Feed Alternative: Mixed HSW Organic Slurry Offloading and Rehabilitating the Existing Primary Sludge Wet Well Layout (Solids Building, First Floor)

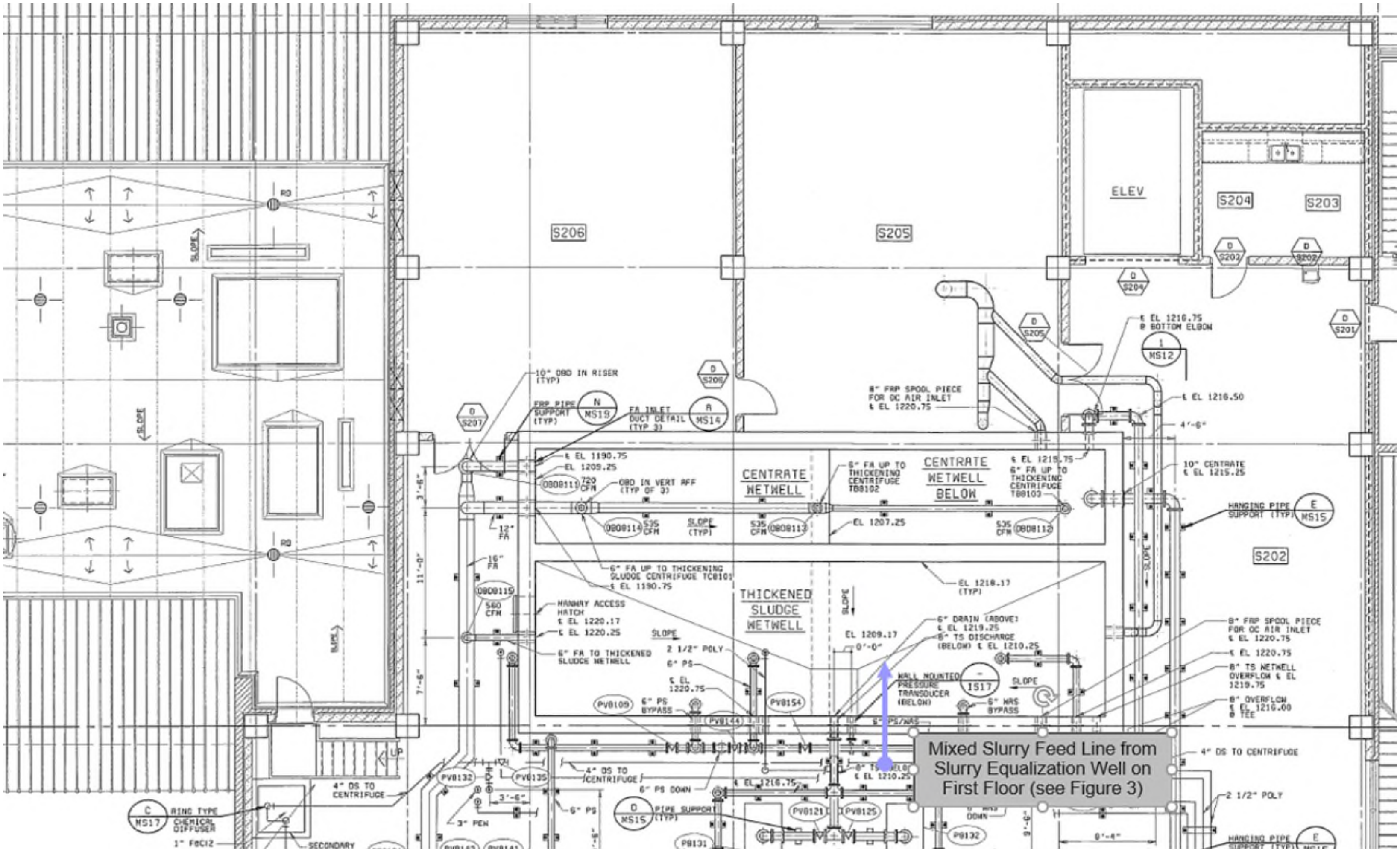


Figure 4. **Direct Equalization Tank Feed Alternative: Mixed HSW Organic Slurry Transfer to Digester Control Building Layout (Solids Building, First Floor)**

4.3 Biogas Utilization

The co-digestion of food waste has the potential to more than double the current digester biogas production at NWWRP. Among the many available options for biogas utilization, the most viable options for NWWRP include the following alternatives.

Cogeneration with Existing Engine

Currently, biogas directly from the digester is supplemented with biogas from the storage tank or natural gas to peak shave electrical utilization during peak daytime hours, as described in Section 2.6 Biogas Utilization. Additional biogas from HSW addition could potentially improve engine operations by supplying the total amount of gas required to run the engine without supplementing any gas from the storage tank, simplifying operations and mitigating the need to switch over to natural gas while the storage tank is being refilled after depletion. Alternatively, the existing engine may be operated continuously throughout the day and night while biogas is available.

Expanded Cogeneration

Digester biogas as a versatile renewable energy source. Biogas can often offer wastewater treatment plants cost savings or income in the form of generated heat, electricity, and/or natural gas. Electricity and heat cogeneration options include internal combustion engines, microturbines, stirling engines, and fuel cells. Internal combustion engines are the most common application due to the greater energy efficiency and multi-part heat recovery system, including jacket cooling water, intercooling, and exhaust heat. Microturbines and fuel cells generally produce electricity in smaller increments and require the biogas to be treated to higher quality and higher pressure that the internal combustion engine. This requires more advance treatment technology resulting in higher capital expenditure, operation and maintenance requirements, and electricity draws. Stirling engines, or external combustion engines, do not require highly treated biogas, however, are only available in low electricity production increments.

As NWWRP already operates an internal combustion engine and has the space to expand the existing system, therefore, other cogeneration options are not financially viable for NWWRP at this time.

Another alternative of interest included expanding the existing cogeneration system by adding a second, similar sized engine model in the existing engine room to expand the electric production capacity from biogas. The selected model for CHP expansion was the Caterpillar G3516 which is an 800-kW engine, with roughly the same footprint as the existing 600 kW Caterpillar G3512E engine. A budget price for quote for the CHP equipment package was $750,000, which includes freight to the site, the generator unit, radiator unit, exhaust silencer, and engine start up. It should be noted that no heat recovery systems were included as NWWRP does not currently recover heat from the existing CHP engines and does not plan to implement this in the future. Additional costs required for installation would include constructing the various piping and electrical interconnections required for the various engine system components.

A new H2S removal system was recommended upstream of biogas compression to protect the new CHP engine equipment from corrosion. Biogas would then pass through the existing compression and moisture removal system and be fed to the expanded set of engines (1 existing, 1 new). Engine fuel would supplemented with biogas from the storage tank or fuelled by natural gas to peak shave electrical utilization during peak daytime hours, as described in Section 2.6 Biogas Utilization. Additional biogas from HSW addition could potentially expand both engines operations by supplying the total amount gas required to run the engine without supplementing any gas from the storage tank, simplifying operations and reducing the need to switch over to natural gas when the storage tank is being filled after depletion. Alternatively, both engines may be operated continuously throughout the day and night while biogas is available.

Analyses involving the existing CHP system assumes no biogas pre-treatment for siloxanes and H_2S. CHP engine specifications typically require feed gas that is less than 200 ppm H_2S; since biogas at NWWRP is, on average, below this threshold, significant O&M savings are not anticipated if biogas is treated for H_2S prior to use in the CHP system. NWWRP's biogas has siloxane concentrations of approximately 3,500 µg/m^3 (which is 3.5 ppm) comprised mostly of D4 and D5 siloxanes, which is within the typical range for WWTP biogas. Siloxanes at these concentration will foul engine cylinders and valve chambers, meaning siloxane treatment upfront of the CHP system would greatly ease the burden on the engine operation and maintenance staff and extend the useful life of the engine.

Unison estimated that a biogas pre-treatment system, including H_2S, siloxane and moisture treatment, would cost approximately $540,000 and Arcadis estimates that the installed cost would be approximately $825,000. With siloxane treatment, Arcadis estimates NWWRP would see an extension to major maintenance procedures by 33%, i.e top ends would be extended from 20,000 operating hours to 30,000 and overhauls would be extended from 40,000 operating hours to 60,000 operating hours. Current O&M costs for the CHP system are approximately $0.036/kWh produced which translates to approximately $62,000 per year in O&M costs for the CHP system under current engine operations. A 33% reduction to the operating costs would yield an O&M cost of $0.024/kWh produced, which is a typical operating cost for an engine, and would translate to $41,000/year in O&M costs, which is an annual savings of $21,000/year. Unison estimated siloxane media changeout cost of $14,500/changeout, and it is estimated that at least once changeout per year would be required. Therefore, after accounting for siloxane media costs, annual savings are reduced to $6,500 per year, and this value neglects the power costs and associated O&M costs for the pre-treatment system. Considering this, it is not anticipated that installing a biogas pre-treatment system would yield a rapid payback period considering it generates annual savings of less than $6,500 per year with approximately $825,000 in capital expenditure required.

An additional engine may have significant effects on the air pollutants at NWWRP. An analysis of the expanded CHP systems effect on the Air Quality Permit Analysis is provided in Appendix B.

RNG Production

Under this alternative, biogas would be sent to a renewable natural gas (RNG) upgrading system. RNG is biogas that has been treated to remove contaminants and inerts, such as CO_2, to meet the natural gas pipeline quality specifications included in Appendix C. RNG can be generated either via a membrane or pressure swing absorption (PSA) upgrading systems. Both technologies have proven performance at municipal wastewater facilities for digester gas upgrading, with larger systems on the order of 500 scfm or greater tending to favour PSA and smaller systems tending to favor membranes. The upgrading skid being considered for the NWWRP including biogas from mixed HSW addition is sized at 400 scfm input biogas which falls right in between the scale sizes for the two technologies The two RNG upgrading systems evaluated for this study were: a 400 scfm BioCNG™ membrane upgrading skid manufactured by Unison Solutions and a 400 scfm MolecularGate™ PSA upgrading skid manufactured by Guild Associates. The BioCNG™ system utilizes an Air Liquide membrane system that is furnished by Unison; the BioCNG trademark is a result of a partnership between Air Liquide and Unison for the use of membrane systems in municipal wastewater treatment settings. The systems are considered to have similar capital costs and operating needs, the main difference being that a membrane system requires H_2S, moisture, and siloxane pre-treatment while PSA systems do not.

Both RNG upgrading technologies require the biogas feed to be pressurized in the range of 150-200 psig, requiring a significant power load to generate RNG. The RNG system feed compressor must be located in close proximity to the upgrading skid to minimize pressure losses and simplify piping to the compressor since recycle streams are necessary. As a result, the current 80 psig liquid ring compressor cannot be used for the feed compression to RNG and the new RNG feed compressor cannot replace the liquid ring compressor in its current footprint. The RNG product gas will have a pressure between 90 -140 psig, meaning that the product gas pressure will need to be stepped down prior to injection into the adjacent natural gas (NG) distribution pipeline.

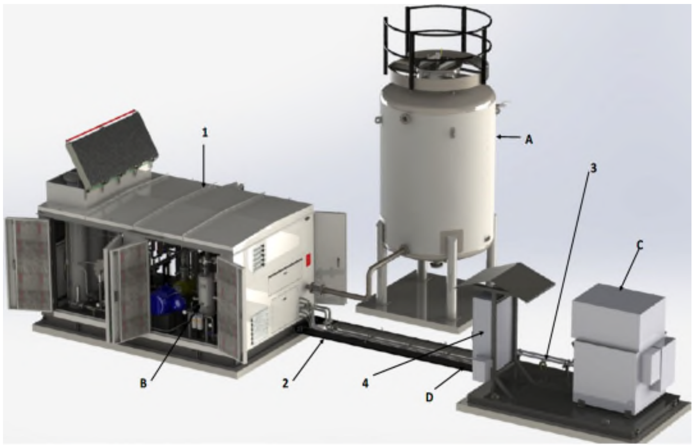


Figure 5. and Figure 6. BioCNG^{TM} Membrane Upgrading Skid and PSA Upgrading Skid

Biogas to RNG via Membrane Skid

The membrane upgrading skid employs a polymer membrane that is highly selective against water and CO_2 and slightly selective against O_2 to yield a product gas that is approximately 98% methane and a tail gas that is approximately 4% methane and 95% CO_2. Due to the membrane's high selectivity for methane, approximately 97% of the methane in the feed biogas is captured; PSA capture efficiency is approximately 92%, meaning that RNG generation potential is maximized with membrane technology.

Table 20. Membrane Skid Parameters

Parameter	Model Value	Unit
Capital Cost	$3,446,000	$
Annual Maintenance Cost	$22,000	$/year
Rated Capacity	400	scfm
Power Draw at Rated Capacity	154	kW
CH_4 Capture	97%	%
Gas Pre-treatment Cost	$0.85	$/mcf Biogas fed
Availability	95%	%

Since H_2S can foul the membranes, the biogas feed must be pre-treated for H_2S prior to processing via the membrane. H_2S pre-treatment would occur in a 17' tall media scrubbing vessel that is located separately from the treatment skid. The media to be used for H_2S scrubbing requires saturated gas for effective performance, therefore, H_2S treatment must occur prior to feed gas drying and compression.

The biogas feed is also treated for siloxanes in a separate scrubbing system located downstream of the feed gas compression on the treatment skid itself and requires a consumable media. The total biogas pre-treatment cost of approximately $0.85 per Mcf of biogas feed – currently the specific H_2S media cost is $0.10 per Mcf of biogas fed and the specific siloxane media cost is approximately $0.75 per Mcf of biogas fed.

Biogas is fed to the membrane system and pressurized to 200 psig, the power draw of 154 kW at its full rated capacity of 400 scfm. The RNG, or product gas, comes off the skid at approximately 140 psig. See Figure 7 for a process flow diagram and sample layout of the BioCNG membrane upgrading system. The capital and operation expenses associated with the membrane system are summarized in Table 20.

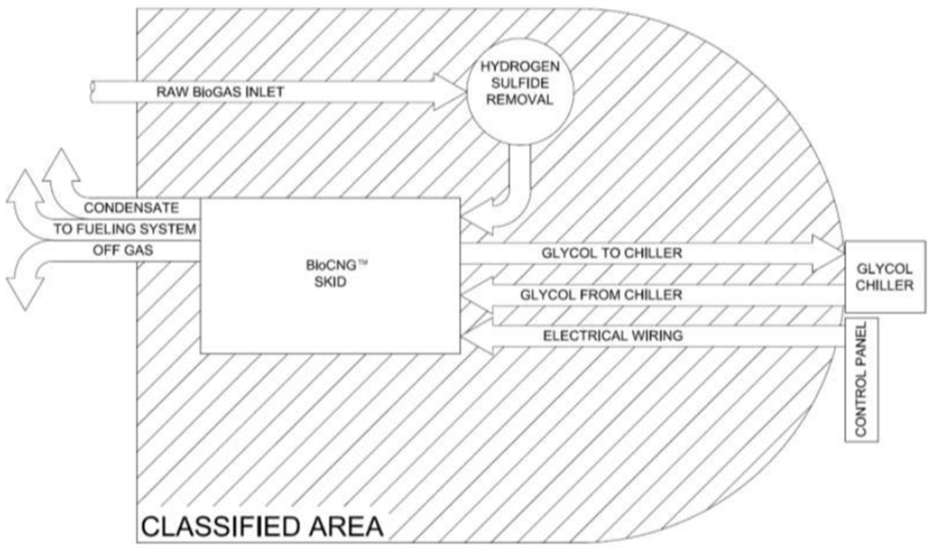


Figure 7. BioCNG Membrane Upgrading System

Biogas to RNG via Pressure Swing Adsorption (PSA) Skid

The PSA skid uses a regenerable adsorption media to separate the methane from the other constituents in biogas. The PSA skid separates molecules based on size, meaning that it is less selective than the membrane system and is not capable of removing O2 and N_2 in the biogas feed. As a result, it is important that O_2 concentrations in the biogas feed be kept below 0.1%, which is not anticipated to be an issue with properly operated anaerobic digesters. The PSA skid product gas is approximately 96% methane and a tail gas that is approximately 11% methane and 86% CO_2. This equates to a lower methane capture compared to the membrane system at 92% versus 97% meaning RNG generation rates will be slightly lower when using a PSA than when using a membrane.

Table 21. PSA Skid Parameters

Parameter	Model Value	Unit
Capital Cost	$2,679,000	$
Annual Maintenance Cost	$30,000	$/year
Rated Capacity	400	scfm
Power Draw at Rated Capacity	171	kW
CH_4 Capture	92%	%
Gas Pre-treatment Cost	$0	$/mcf Biogas fed
Availability	95%	%

Unlike the membrane system, the PSA skid removes all contaminants in one step, meaning that no separate treatment is required for siloxanes and H_2S. As a result, there are no pre-treatment media costs associated with the PSA system.

The membrane skid requires biogas feed pressures of 100 psig and the product gas comes off the skid at approximately 90 psig. Despite the fact that the PSA skid requires the feed gas to be pressurized to 100 psig compared to 200 psig for the membrane system, the PSA skid has a higher power draw of 171 kW compared to 154 kW for the membrane skid due to the fact that the PSA skid requires a vacuum compressor to regenerate the adsorption media in addition to the initial feed compression. The maintenance cost of the PSA skid is higher than the membrane skid at $30,000 per year versus $22,000 due to the increase in maintenance requirements associated with the PSA skid vacuum compressor. See Figure 8 below for a process flow diagram of the PSA system. The capital and operation expenses associated with both systems are summarized in

Table 21.

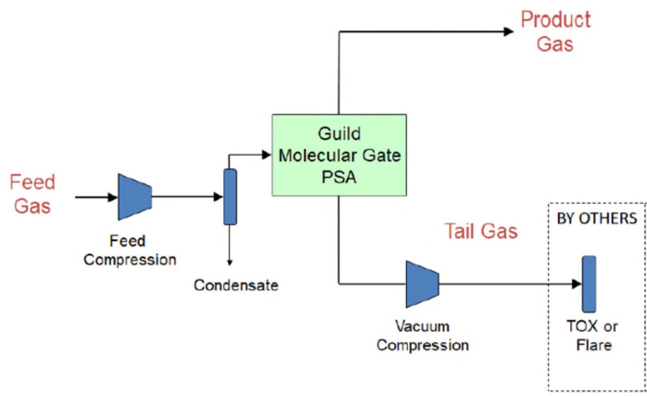


Figure 8. Guild PSA Upgrading System

RNG Tail Gas Treatment

Upgrading biogas to RNG generates two product streams: the energy rich RNG product gas and the energy lean tail gas, primarily composed of rejected inerts, such as contaminants and 4 -11% methane (by volume). The methane capture of RNG upgrading systems range from 92 - 97%. Due to the lean heating value of the RNG tail gas, in order to meet air permitting limits, a thermal oxidizer system must be used to treat the tail gas.

Figure 9. Thermal Oxidizer

A thermal oxidizer employs temperatures over 1500°F and residence times of 15 - 30 minutes to yield a methane and contaminant destruction in excess of 95%. The high temperature and residence times allow a thermal oxidizer to combust the tail gas at a methane content of approximately 12%. The PSA skid, minimal make up NG is required to meet the required heating value since the tail gas is approximately 11% methane while the membrane skid tail gas would require approximately 20 scfm of makeup NG at the thermal oxidizer's rated capacity. Capital and operation expenses associated with thermal oxidizer are presented in Table 22.

Table 22. Thermal Oxidizer Flow Parameters

Parameter	Model Value	Unit
Capital Cost	$489,000	$
Annual Maintenance Cost	$15,000	$/year
Power Draw	22	kW

Biogas Piping System

In the current biogas handling system, biogas from each digester is collected via one 8" pipe. At the current average biogas generation rate of 66 scfm, the gas velocity is 3.2 feet per second (fps), well below maximum best practice velocity of 12 fps. At maximum HSW loading to the digesters, the biogas generation rate per digester under this analysis was calculated to be 139 scfm, equating to a gas velocity of 6.6 fps. The current digester handling system could accept a maximum of 250 scfm of biogas from each digester before the best practice maximum velocity of 12 fps is reached.

For connection to a new RNG upgrading system a new 10-inch stainless steel biogas piping connection would be installed in the digester control building in the header pipe just downstream of the existing foam separators. This new 10-inch biogas line would connect to a new RNG upgrading system located to the West of the existing Digester Control Building. The RNG upgrading system would have independent feed compressors, gas pre-treatment/chilling, and the RNG upgrading unit process integrated into a comprehensive gas treatment skid. Product gas would be routed through new 2-inch buried piping connections directly to a new NG pipeline interconnection near the southwest corner of the plant yard. This NG new interconnection point and metering station would be coordinated with the planned NG relocation/rehabilitation work in this area. Tail gas would be routed to a thermal oxidizer for final treatment.

Figure 10 through Figure 12 show the process flow diagram and the proposed layout for biogas piping to the Co-generation and RNG skids.

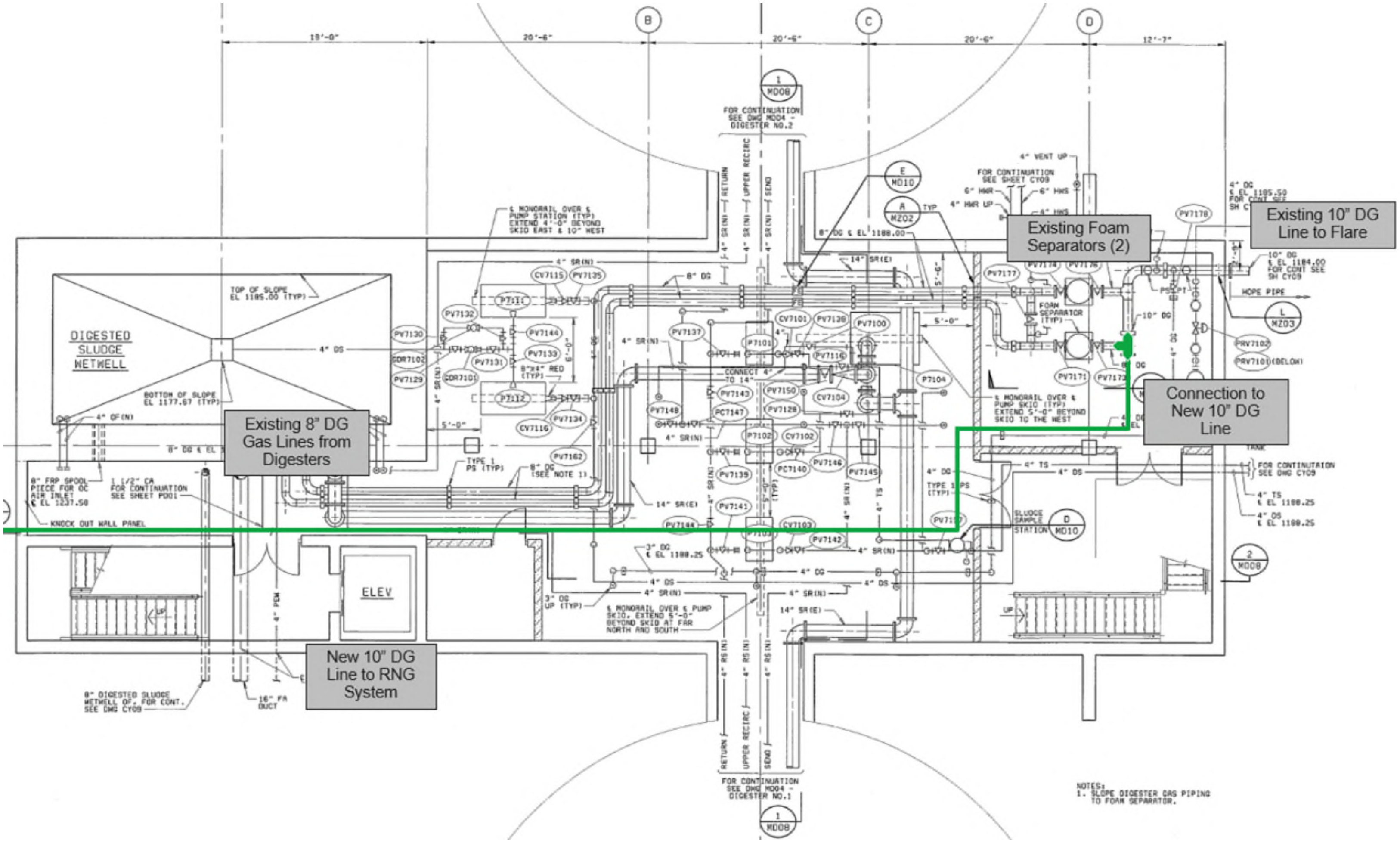


Figure 10. Proposed Biogas System in Digester Gas Building Layout

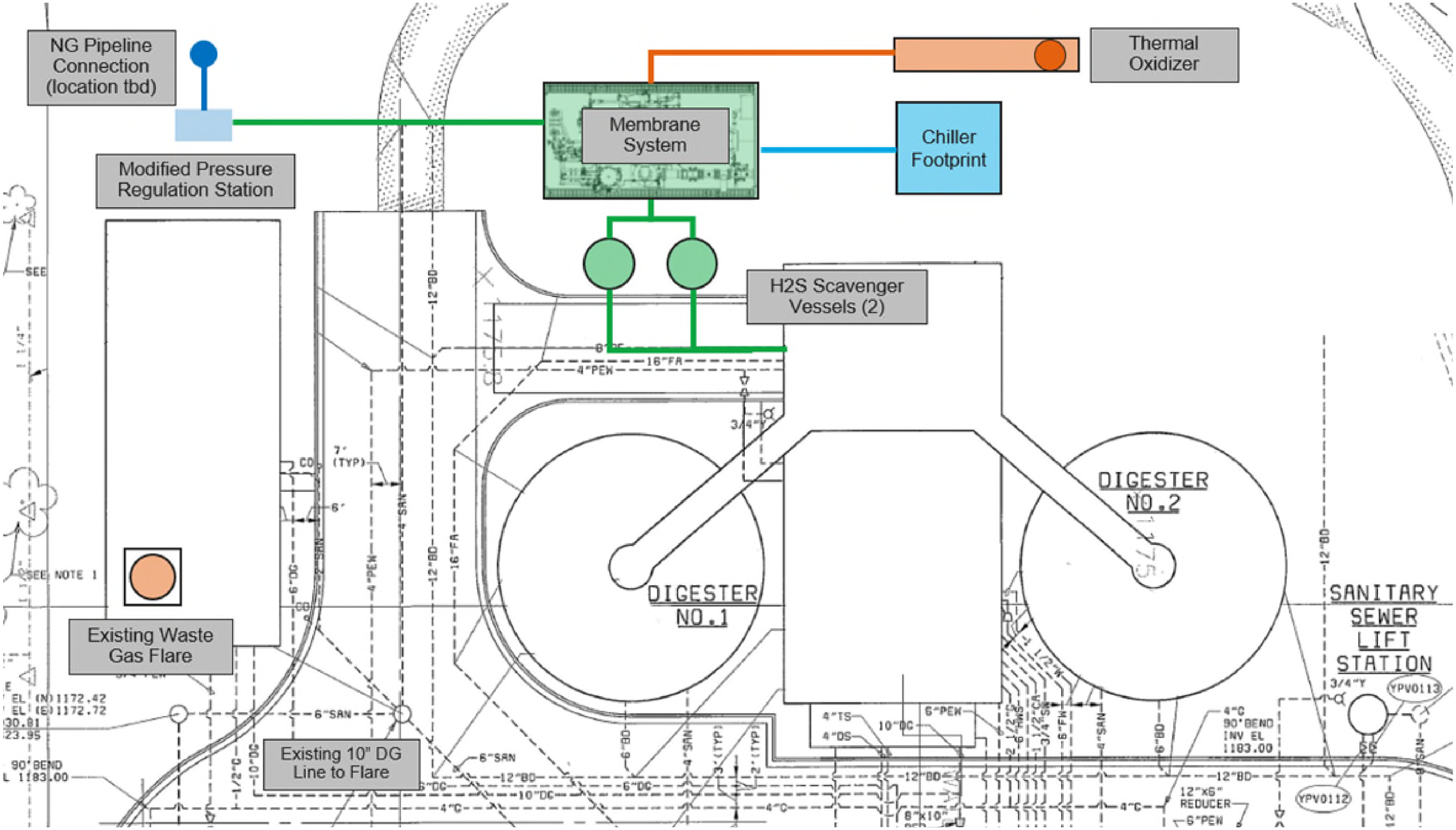


Figure 11. Proposed RNG System Layout Alternative 1: Membrane with Thermal Oxidizer

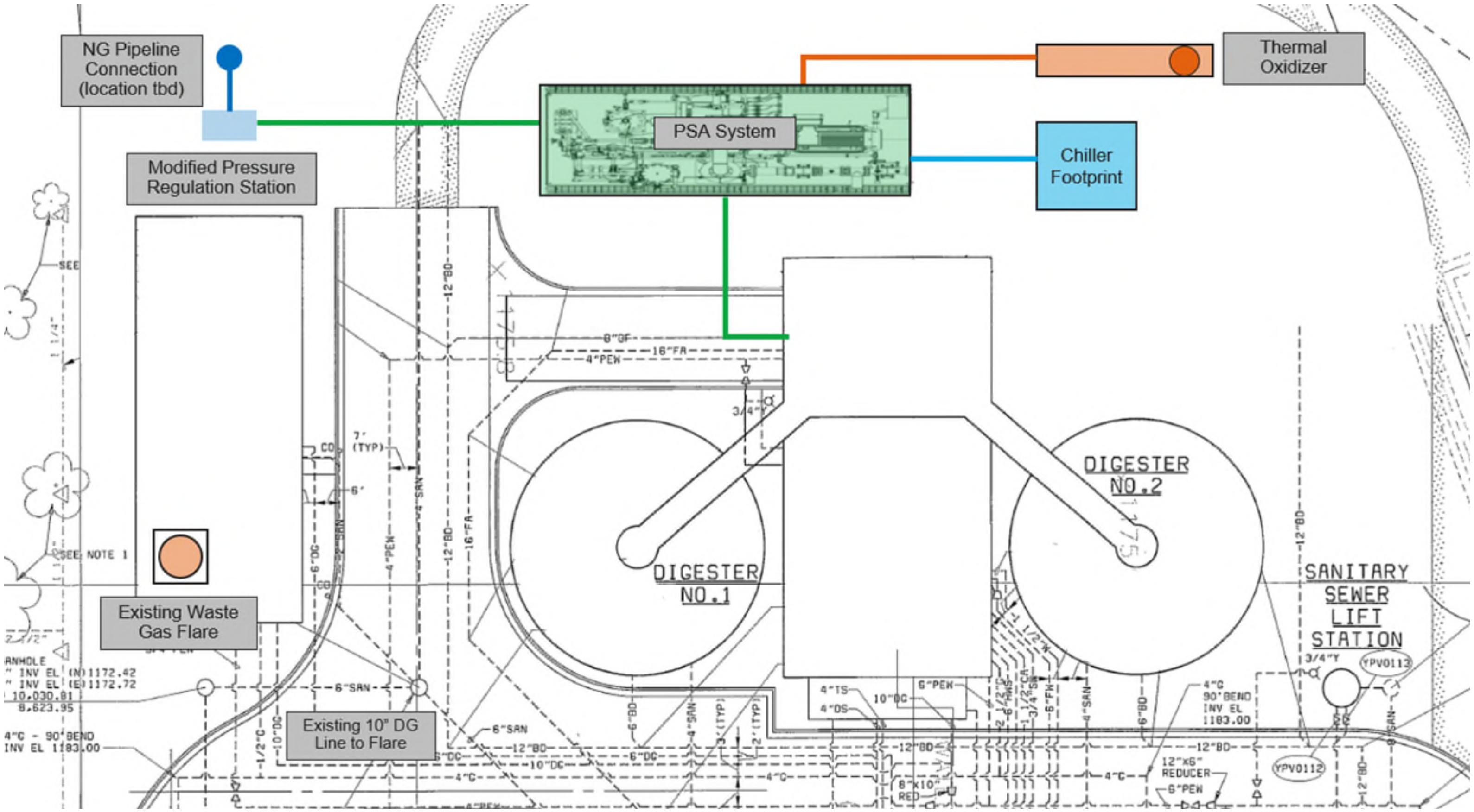


Figure 12. Proposed RNG System Layout Alternative 1: PSA With Thermal Oxidizer

RNG to NG Utility Pipeline

The turnkey RNG upgrading skid is provided with automatic gas purity controls designed for unattended operation. Product RNG gas is 90-150 psig. The existing Riverview gas system operates at approximated 45 PSI, therefore, the RNG product gas must be depressurized prior to injection into the NG utility pipeline. This would provide an ideal pressure buffer that would be regulated to 45 psig at the metering station.

A modified pressure regulation system must be installed between the RNG and Riverview system to avoid over-pressurization issues and to come into compliance with DOT codes. This modified station will be designed to directly connect the RNG production system to the Riverview pipeline and shall be designed meet the definition of a service line in the pipeline safety regulations. This modified station shall include two regulator shut-off valves in the event of over pressurization within the system. Over pressure protective devices are required at every pressure reducing station that supplies gas from any system to another system with a lower maximum allowable operating pressure by the natural gas industry safety codes and laws. A regulator shut-off valve accomplishes over pressurization protection by containment. The pipeline injection system will shut off completely until the cause of the over pressurization is determined and the device is manually reset. Therefore, during these periods, the natural gas will require redirection. It is recommended that additional steps are taken that, in the case of over pressurization, the RNG can be redirected for utilization in the boilers or the engines. As a last resort, the RNG will be redirected directly to the waste gas burner.

Generally, modern gas regulators are highly reliable devices; however, failure could potentially occur due to several reasons such as physical damage, equipment malfunction, and the presence of foreign material in the gas stream. There is no design standard that is applicable to all situations, however, the industry encourages multiple layers of protection to mitigate the potential of failure. Common over-pressurization protection designs include the following.

- Use of in-line monitor regulators that control pressure upon failure of the primary control regulator.
- Use of relief devices that vent excess gas pressure to the atmosphere.
- Use of automatic-shutoff devices, such as positive shut off valves and fail close regulators to interrupt the supply of gas.
- Installation of filters and strainers to eliminate debris entering a regulator.
- Deployment of signalling devices that notify operating personnel of equipment failure or abnormal operating conditions (AOCs).
- Use of telemetry and transducers that are monitored remotely with corresponding alarm set points.

An analysis of the Riverview Gas System current demand was performed. Based on the modelled RNG production values, the Riverview system does not have consistent and collective natural gas demand to accommodate the RNG production at NWWRP. See Table 23 and Figure 13 for details on the highest expected RNG production and the Riverview Gas System daily consumption details.

Table 23. Estimated RNG Production and Riverview Gas System Flow Parameters

Estimated RNG Production at NWWRP		
Condition	**Value**	**Unit**
Peak RNG Flow	11,233	scfh
Avg RNG Flow	8,700	scfh
Daily Average Riverview Gas System Flow		
Condition	**Value**	**Unit**
Total Average	6,104	scfh
Avg Night (10 PM - 6 AM)	4,025	scfh
Avg Day (6 AM - 10 PM)	7,142	scfh

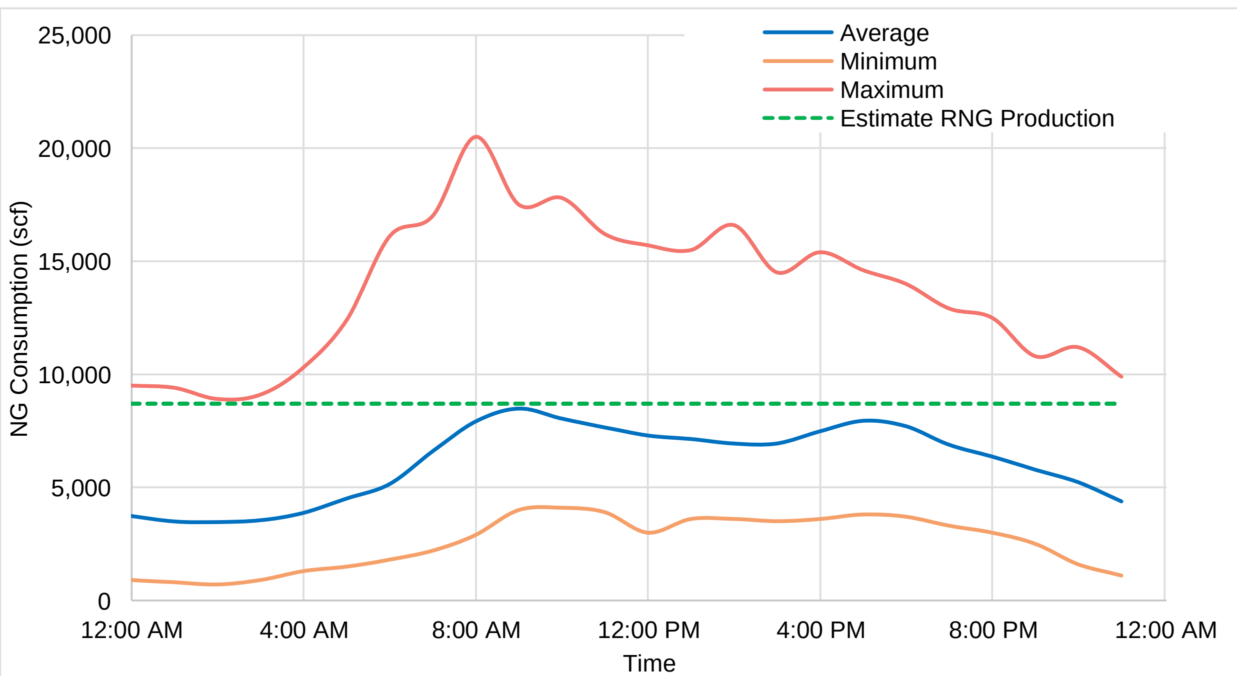


Figure 13. Riverview Gas System Average Daily Consumption

It was communicated that the Mesa gas system, the nearest natural gas system to the Riverview gas system, has substantial demand. Therefore, it is recommended that modified regulation station(s) are installed between the Riverview gas system to the Mesa gas system at

GRS93 and/or GRS56 – The station feeding between the Riverview 45 PSI and Mesa 25 PSI systems would have to be a modified design to allow for one-way directional flow. Each modified pressure regulation station is expected to cost approximately $50,000. The location of the interconnections is provided in Figure 14 below.

Figure 14. Riverview Gas System Plan

It was discussed that there may be a potential to convert the existing Riverview 45 PSI system to a 25 PSI system. Should this option be pursued, only a simple pipe connection with a one-way valve and meter between the system would be necessary. This solution would be considerably less expensive.

5 SOLIDS AND ENERGY MODEL

This section includes a more detailed discussion of the plant level solids and energy flow modelling framework and methodology, as well as the modelling analyses and results to drive decision making regarding mixed HSW organic slurry loadings and biogas utilization strategies.

5.1 Framework for Flow Model

The primary process inputs to the Flow Model are the amount of primary sludge and WAS being generated and treated at NWWRP as well as the load of OSW and FOG being added to plant digesters. These values are set as described in Table 1; however, can be easily modified as user inputs for future plant changes or as additional data becomes available. The user can then evaluate modifications to the existing facilities by selecting to activate potential processes or directing items such as biogas energy or supplemental natural gas fuel to various processes. Activating a future process changes the mass and energy flows affected by that process throughout the plant while also activating capital and O&M costs associated with that future process. The flow model user interface is shown in Figure 19 below.

Two of the most important inputs to the Flow Model are the amount of OSW and FOG hauled to the pre-processing facility and the division of sludge and mixed HSW organic slurry loading to the digesters. From these model values, results are generated for the digestion capacity and digester products including biogas energy produced and the amount of biosolids generated. All the performance values for current conditions were calibrated to the available plant information provided as discussed in the previous section

Energy is input into plant processes through biogas production or through the purchase of natural gas. In the model, varying energy flows can be directed to various utilization processes such as the existing CHP engine or a new upgrading system for RNG production. The amount of energy flowing into a given process was modified based on the particular scenario being examined.

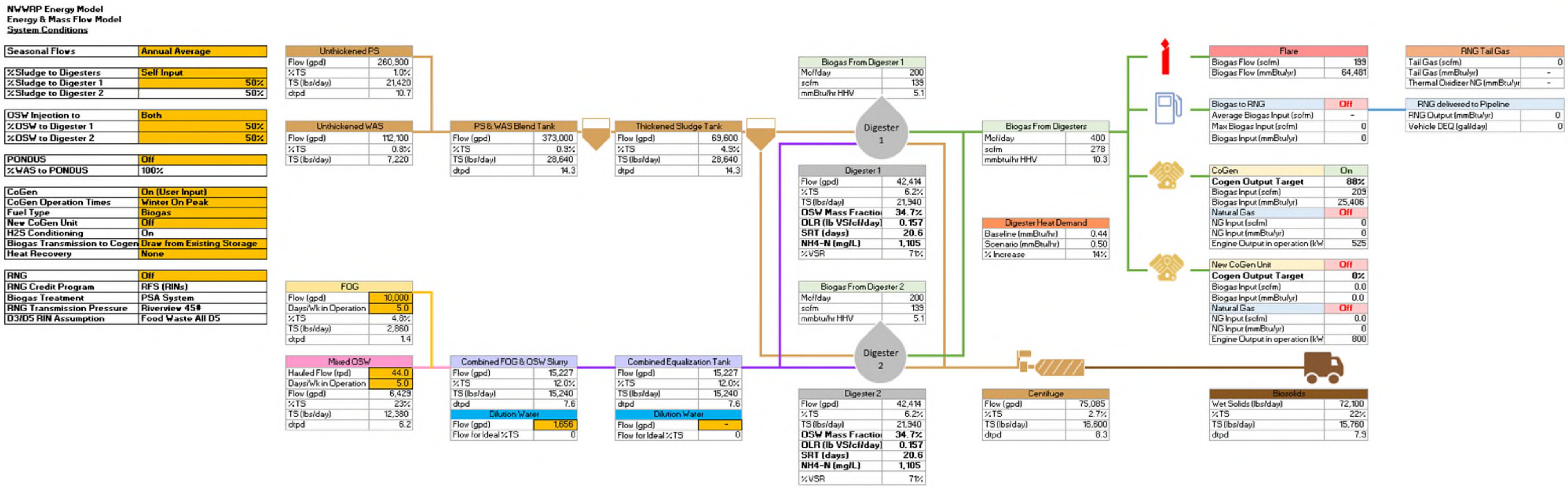


Figure 15. Arcadis Mass and Energy Model Dashboard

The main outputs of the Flow Model are preliminary annualized 'Savings Over Baseline' and GHG emission reduction.

Annualized Scenario Savings

Annualized scenario savings was the selected economic metric for evaluating potential scenarios. This includes a totalized value of many cost items on an annual basis such as electrical power use and generation savings, natural gas usage or offsetting, vehicle fuel offsetting as well as items like RIN revenue and savings from landfill tipping fees by diverting OSW. Capital costs for new processes are translated into an annualized cost, similar to an annual payment that would be made on a bond, with an assumed term of 20 years at 3% interest rate. Additional O&M costs and energy needs are also accounted for in new processes activated.

All scenarios evaluated assumed utility energy prices of $4.74/mmBtu for natural gas, based on average natural gas charges to NWWRP between February 2017- August 2018; and varying electric rates based on the provided rate schedules as summarized in Table 8. The rate for sending material to a landfill via a 3rd party hauler was $14.25 per wet ton of sludge and $30.31 for OSW. When OSW is diverted to the digesters, the related hauling fee was assumed to be offset. When RNG was being produced and sent to the City CNG vehicle fleet, a fuel offset price of $0.46 per diesel gallon equivalent (DGE) was used. RIN pricing was based on an annual average value over the past year which was $1.85/ethanol gallon equivalent for a D3 RIN and $0.34/ethanol gallon equivalent for a D5 RIN. All these unit cost input values may be varied within the model.

GHG Emission Reduction

The greenhouse gas (GHG) emission reduction was also quantified for each scenario, with the main reduction source being energy recovered from renewable biogas. Energy generated from biogas will offset energy that must be generated from fossil fuels. The amount of GHG reduction will depend on the type of energy being offset. The value for CO_2 equivalents associated with electricity usage (1,384.8 CO_2 lb/MWh) was retrieved using eGRID 2016 (the most recent available version), which is an EPA created software application. eGRID is used to derive composite data from regional electric generation zones to approximate the composite amount of CO_2e emitted for each MWh of electricity produced in the region. The reported value is from the AZNM eGRID sub-region, which contains the Mesa area.

Diesel gallon equivalence is approximated at 125,000 btu per gallon diesel fuel and CO_2 equivalents associated with diesel usage (22.40 CO_2 lb/gal).

The net GHG emissions for each scenario are calculated as the reduction resulting from using biogas for power generation instead of the power draw, combustion of natural gas, and use of vehicle fuel involved with each scenario. It should be noted that for the parameter 'GHG Reduction' a positive number indicates an overall reduction in emissions while a negative number indicates an overall increase in emissions.

5.2 Digestion Limitations

When considering co-digestion of organics, it is critical to focus on multiple factors in order to ensure that the food waste is not negatively impacting operations. The following process performance parameters and costs are adapted from reported project data, literature values, and experience with the unit processes. These performance parameters are built into the logic of the Flow Model.

The process performance parameters are adapted from reported project data, literature values, and prior experience with co-digestion, as well as ASU's bench tests. The target digestion parameter values, as shown in Table 24, are recommended to ensure stable co-digestion at NWWRP. It is important to clarify that the suggested limits are the targeted long-term operation values. The six primary digestion parameters which were evaluated are as follows:

- SRT / Hydraulic Loading Capacity
- Organic Loading Rate / Volatile Solids Loading Capacity
- Organic Mass Fraction
- Ammonium Concentration
- Volatile Fatty Acid (VFA) to Alkalinity Ratio
- Soluble Chemical Oxygen Demand (sCOD)

Table 24. Suggested Digestion Parameter Values

Digestion Parameter	Target	Limits	Unit
Solids Residence Time	20	17.5 (Min)	Days
Organic Loading Rate	0.185	0.2 (Max)	lbs VS/cf/day
Organic Mass Fraction	35%	50% (Max)	%
Ammonium Concentration	1,500	2,000 (Max)	mg NH4-N/L
pH	7	6.5 (Min) 7.6 (Max)	
Soluble Chemical Oxygen Demand (sCOD)	5,000	10,000 (Max)	mg COD/L

SRT / Hydraulic loading capacity

The most critical parameter to examine is the effect of the OSW addition on digester solids retention time (SRT), most notably maintaining an SRT above 15 days in the digesters for all digester influent conditions to meet land application permit requirements as per EPA 40 CFR Part 503 Biosolids Regulations. A minimum SRT ensures that the necessary microorganisms are being produced at the same rates they are wasted through biosolids effluent. To promote efficient digester operations, SRT under average conditions is typically targeted to be 20 days, or greater, to account for extended peak flows seen by the Plant. To ensure an appropriate digestion conditions are maintained, it is recommended that the average digester SRT not fall below 15 days under the maximum organic waste loading conditions.

Organic Loading Rate / Volatile solids loading capacity

Organic loading rate (OLR) to the digester is another key parameter that can be used as a digestion stability limit. Since OSW and FOG are concentrated in organic load, avoiding overloading the digesters and the potential for going sour is critical for operations. A typical organic loading range for efficient digester performance treating municipal WWTP sludges is 0.12-0.16 lbs VS/cf/day. NWWRP currently operates at an average 0.10 lbs VS/cf/day. There has been considerable research conducted into the loading rate limits when OSW is introduced, with most findings indicating higher loading rates are possible due to the more readily degradable nature of the OSW relative to sludge.

From experimental data and full-scale work feeding OSW to digesters at other installations, the maximum range of stability for OLR has been observed to be around 0.18 to 0.20 lbs VS/cf/day when there is adequate time allowed for digester acclimation. Arcadis has direct experience at Gloversville-Johnstown WWTP in upstate New York where dairy waste was added in excess of 0.25 lbs VS/cf/day at steady state conditions.

For NWWRP, it is recommended that a relatively conservative OLR limit of 0.185 lbs VS/cf/day be targeted under the maximum organic waste loading conditions. Considerations for items such as modular expansion of OSW processing equipment should be made to allow expansion of loading rates in the future if deemed operationally feasible after initial OSW loading rates are reached.

Organic Mass fraction

The organic mass loading fraction, or the volatile solids (VS) from OSW & FOG as compared to the organic mass of sludge VS into the digester is another critical parameter to avoid overloading of the digester. Typical organic mass faction of OSW & FOG to sludge is 35% from reported literature values and experience with full-scale installations receiving large percentages of imported organic waste. Arcadis has direct experience at Gloversville-Johnstown WWTP in upstate New York where dairy waste was added as more than 50% of digester organic mass loading under steady state conditions. For NWWRP it is recommended that 35% be the target Organic Mass Fraction loading limit with considerations for modular future expansion if additional loading is deemed operationally feasible after initial OSW loadings are conducted.

Ammonium Concentration

At the expected maximum organic waste addition based on and Organic Mass Fraction of 35%, the increase in ammonia loading from OSW was examined to determine potential impacts on digester performance and overall plant nutrient balance. Nitrogen, in the form of ammonium, is released during digestion due to the breakdown of proteins which are then recycled to 91st Avenue WRP as centrate.

Currently, OSW readily degradable VS were estimated to be 20% protein by mass. For the purpose of this analysis, protein hydrolysis was estimated to yield 20% by mass nitrogen, meaning every ton of accepted OSW increases the nitrogen loading to the digester by approximately 15 lbs. The effects of the ammonium loads from OSW are also examined in terms of the projected effect in overall plant nutrient balance. The current centrate TKN concentration within the digesters is 550 mg/L based on plant data which is assumed to be entirely ammonium and considered a good proxy for digester concentrations. From experience with plants conducting pre-digestion lysis and enhanced cell digestion, ammonium limits become limiting and tend to produce negative operational effects at concentrations approaching 1,500-2,000 mg/L. It was estimated that 20% of the mixed HSW organic slurry will be protein that will increase the ammonium concentrations in the digesters and recycle loads from the centrate.

The NWWRP dewatering centrifuge treatment downstream of the digesters is in turn sent via sewer to the head of the 91st Avenue WRP. This increase in centrate ammonium concentration may have resulted in additional struvite production if the centrate was reintroduced to the NWWRP liquid stream. However, based on the diversion of centrate away from NWWRP, it is not expected that the addition of HSW effect operations at NWWRP, or negatively affect 91st Avenue WRP due to the dilution within the Mesa sewer system prior to the plant.

pH/sCOD

Organic solid waste is rich in carbohydrates and proteins which can hydrolyze quickly during digestion. The rapid production of VFAs can overwhelm methanogenesis, in part due to the slower growth kinetics of acetoclastic methanogens, resulting in an overall drop in pH [1] [2]. The desired range for methanogens is generally between 6.5 and 7.6. However, it is recommended to maintain digester pH between 6.8 - 7.2.

Under pH of 6.5, digester is in danger of souring. While this is not expected to take place at NWWRP due to the multiple equalization and acclimation procedures in place. Section 7.3 includes a detailed breakdown of the start-up, operational and monitoring procedures for the digester in order to minimize the risk of digester upset during co-digestion commencement and ramp up. It is recommended that NWWRP take both daily pH readings as well as VFA/Alkalinity ratio reading. VFA/Alkalinity values between 0.3 and 0.4 are typically indicators of stable anaerobic digester. [3] Should NWWRP prefer chemical addition to ensure appropriate pH. Biocarbonate alkalinity can may be added to system, however sodium hydroxide is recommended since it is already maintained on site

Limiting Loading Factor

Based on the preliminary model results with varying OSW and FOG loading to the digesters, the limiting loading factor was found to be the Organic Mass Fraction of 35%. At this Organic Mass Fraction, SRT was still in excess of 20 days, OLR was approximately 0.16 lb VS/cf/day. Increases in ammonium concentrations were not limiting as discussed further below based on the assumed protein content of the mixed HSW organic slurry received. This 35% mass fraction factor was set as the limiting condition when evaluating future digester loading scenarios.

6 MODEL SCENARIO EVALUATION

Multiple scenarios were generated within the model to evaluate NWWRP's co-digestion capabilities, using the digester limitations discussed above. Five sets of scenarios and subsequent scenarios are examined as follow:

Set 1: Co-generation without Mixed HSW Addition

Set 2: Co-generation with Mixed HSW Addition

Set 3: RNG Generation with Mixed HSW Addition

Set 4: Co-generation and RNG Generation with Mixed HSW Addition

Set 5: Participation in the Low Carbon Fuel Standard (LCFS) Program

As described in Section 6.1 below, for each scenario the main comparison values are preliminary annualized 'Savings Over Baseline' and GHG emission reduction. Annualized 'Savings Over Baseline' includes many cost items on an annual basis such as electrical power use and generation savings, natural gas usage or offsetting, vehicle fuel offsetting over the baseline as well as items like RIN revenue and savings from landfill tipping fees by diverting OSW. Alternatively, the net GHG emissions for each scenario are calculated as the reduction resulting from using biogas for power generation to offset the emissions associated with electric power draws, the combustion of natural gas, or use of vehicle fuel involved with each scenario. It should be noted that for the parameter 'GHG Reduction' a positive number indicates an overall reduction in emissions while a negative number indicates an overall increase in emissions.

6.1 Set 1: Co-Generation without Mixed HSW Addition

Set 1 scenarios represent current potential operating scenarios for NWWRP to serve as a basis for comparison for the subsequent scenarios analyzed. Typically, the baseline scenario is represented as the "do nothing" scenario, where the plant does not install or optimize any treatment processes. In this case, the scenarios model the existing CHP engine running during different seasonal and daily peaking periods. Currently, the Plant operates the co-generation system all seasons during peak and shoulder peak hours. Power charges were set using the 2018 electricity rate schedule during seasonal and daily periods, summarized in Table 8 and Figure 2. A 90% engine availability was set to account for downtime due to general maintenance requirements. An engine maintenance rate of $0.036 per kWh/ generated was used to estimate annual engine maintenance costs. Power draw associated with compressing biogas to 75 psig prior to use in the engine was also considered within the model. Scenarios evaluation lower biogas feed pressures to the engine was examined in a subsequent scenario analysis.

To evaluate the most economical engine run-time scenario, the CHP engine performance was evaluated at different seasonal and peak/off-peak periods. The different periods used were developed from the SRP pricing plan and are summarized in Figure 19 and

Table 25 below.

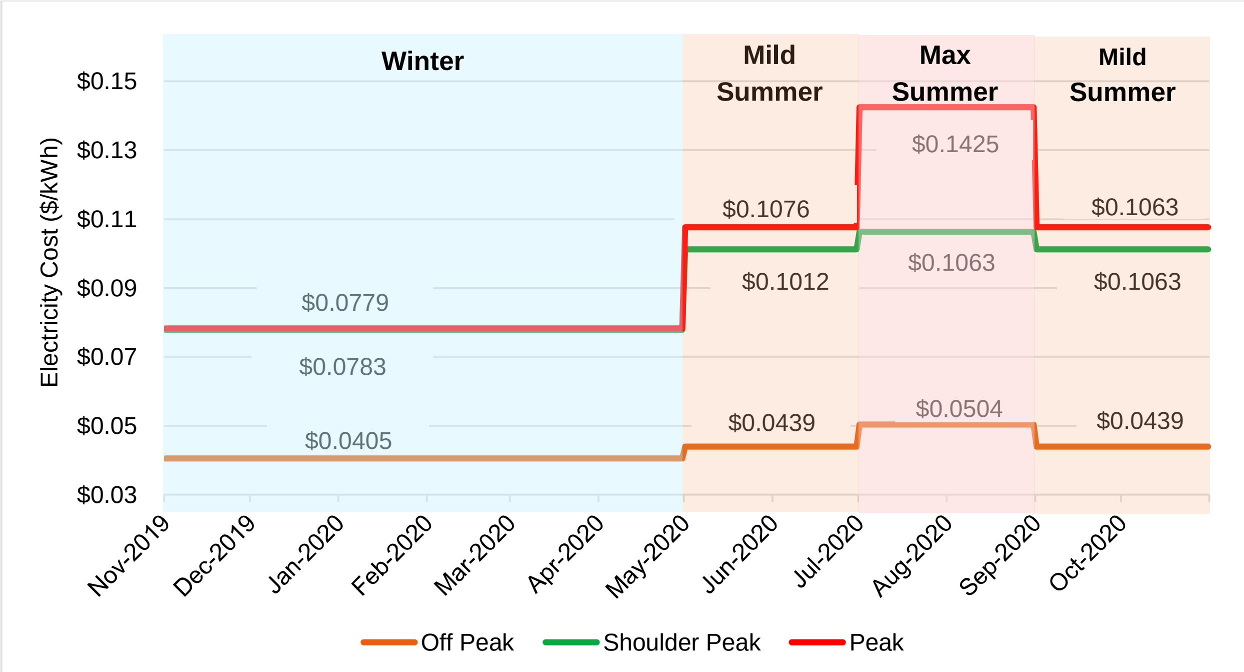


Figure 16. 2018 Seasonal Electrical Power Costs

Table 25. Co-Generation Seasonal and Daily Charge Summary

Seasonal Period	Days/yr	hours/day	hours/yr	$/kWh	kWh/yr	$/yr
Max Summer On-Peak	62	6	335	0.1425	267,840	$ 38,000
Mild Summer On-Peak	122	6	659	0.1076	527,040	$57,000
Max Summer Shoulder-Peak	62	6	335	0.1063	267,840	$28,000
Mild Summer Shoulder-Peak	122	6	659	0.1012	527,040	$53,000
Winter On-Peak	181	4	652	0.0783	521,280	$41,000
Winter Shoulder-Peak	181	4	652	0.0779	521,280	$41,000
Max Summer Off-Peak	62	12	670	0.0504	535,680	$27,000
Mild Summer Off-Peak	122	12	1,318	0.0439	1,054,080	$46,000
Winter Off-Peak	181	16	2,606	0.0405	2,085,120	$84,000

Evaluation in the energy flow model confirms that the most cost-effective use of biogas is to peak-shave as being done under current CHP operations, which is operating the CHP during peak and shoulder peak periods every day of the year. Therefore, the “All year On-Peak and Shoulder-Peak” scenario is used as a baseline to display the existing annual cost savings and greenhouse gas (GHG) reductions of running the co-generation system. The results of the Set 1 scenarios analyses are summarized below.

Scenario 1.1. 'Summer On-Peak Only'

Scenario 'Summer On-Peak Only' models the annual cost savings and GHG reductions if NWWRP operates the engine during "Mild Summer On-Peak" seasonal periods only. This scenario serves as the lowest annualized offsetting scenario available to the Plant if they continue operating their existing co-generation system at 87.5%. In this scenario, the engine operates approximately 994 hours per year, consuming 4,843 mmBtu/year HHV of biogas and 2,832 mmBtu/year HHV of NG. The average power cost offset for this scenario is $0.1194 per kWh, which is 81% higher than the average power cost of $0.0659 per kWh.

The remaining 89% of the biogas generated outside the operational period and which is not stored for later use is flared. This scenario has a negative annual savings since NG purchased for digester heating and CHP fuelling is $37,000 while net CHP electric offsets after O&M is $35,000. GHG reductions are negative since associated NG GHG emissions are 414 MT CO_2e while reductions associated with electric generation are 286 MT CO_2e.

Scenario 1.2. 'Summer On-Peak and Shoulder-Peak'

Scenario 'Summer On-Peak and Shoulder-Peak' models the annual cost savings and GHG reductions if NWWRP operates the engine during "Mild Summer Shoulder-Peak" seasonal periods, as shown in Figure 16. 2018 Seasonal Electrical Power Costs

Table 25. In this scenario, the engine operates approximately 1,987 hours a year, consuming 9,686 mmBtu/year HHV of biogas and 5,664 mmBtu/year HHV of NG. The average power cost offset for this scenario is $0.111 per kWh, which is 69% higher than the average power cost of $0.0659 per kWh.

The remaining 77% of the biogas generated outside the operational period and which is not stored for later use is flared. This scenario generates $16,000 in additional savings and 145 additional MT CO_2e in GHG reductions over scenario 1.1.

Scenario 1.3. 'All Year On-/ Shoulder-Peak' / 'Enhanced Baseline' Scenario

The 'Enhanced Baseline' Scenario assumes optimized current operations, meaning that there is no unplanned CHP downtime under this scenario. Under this scenario models the annual cost savings and GHG reductions when NWWRP operates the engine during "Winter On-Peak" seasonal periods, as shown in Figure 16. 2018 Seasonal Electrical Power Costs

Table 25. Therefore, under this scenario, there is no high-strength waste collected and delivered to the NWWRP. This scenario assumes that City uses biogas to run the City's existing engine generator system to generate electricity on-site and peak-shave (both peak- and should peak-periods, all year around). The biogas is used as it is generated and supplemented with biogas stored in the existing storage tank to operate the engine at approximately 87.5% capacity, equating to 525 kW of power generation. Natural gas is fed to the engine when biogas in not

available (while the storage tank is being filled). It is assumed that the engine has a 90% annual availability.

This serves as an ultimate 'Baseline' Scenario to display the progress NWWRP has already made prior to this evaluation. In this scenario, the engine operates approximately 3,290 hours a year, consuming 16,037 mmBtu/year HHV of biogas and 9,378 mmBtu/year HHV of NG.

The remaining 62% of the biogas generated outside the operational period that is not stored for later use is flared. The average power cost offset for this scenario is $0.0981 per kWh which is 49% higher than the average power cost of $0.069 per kWh. Annual savings for this scenario air lire $7,000 higher than scenario 1.2 and the highest of the scenarios analyzed in this scenario set. GHG reductions increase by 202 MT CO2e per year over scenario 1.2 due to the increased CHP uptime.

This Scenario is considered 'enhanced' because it is the basis for current operations, however, we have confirmed that the existing CHP is not operated every day during peak and shoulder periods. Therefore, we consider this the baseline, should NWWRP enhance their current operation.

Scenario 1.4. 'All Year On-/Shoulder-Peak + Summer Off-Peak'

Scenario 'All Year On-Peak and Shoulder-Peak+ Summer Off-Peak' models the annual cost savings and GHG reductions if NWWRP operates the engine during all seasons during the "Mild Summer Off-Peaks" seasonal periods, as shown in Figure 16. 2018 Seasonal Electrical Power Costs

Table 25. In this scenario, the engine operates approximately 5,178 hours a year, consuming 25,723 mmBtu/year of biogas and 15,041 mmBtu/year of NG. The average power cost offset for this scenario is $0.0785 per kWh, which is 19% higher than the average power cost of $0.0659 per kWh. This margin is not sufficient to offset the cost of NG and the O&M on the CHP causing the annual savings in this scenario to decrease by $20,000 compared to scenario 1.3.

The remaining 40% of the biogas generated outside the operational period and which is not stored for later use is flared. GHG reductions increase by 301 MT CO2e per year relative to scenario 1.3 due to the increased CHP uptime, however the increased O&M demand paired with the decrease in annual savings make this scenario unfavorable compared to scenario 1.3.

Scenario 1.5. 'All Year 24/7'

Scenario 'All Year 24/7' models the annual cost savings and GHG reductions if NWWRP operates the engine for its maximum possible uptime of 90% of the year, or 7,884 hours per year. In this scenario, the engine consumes 38,427 mmBtu/year of biogas and 22,469 mmBtu/year of NG. The remaining 10% of the biogas generated outside the operational period and which not stored for later use is flared.

Due to the further reduction of average power cost offset compared to scenario 1.4, the annual savings in scenario 1.5 decrease by $33,000 relative to scenario 1.4, resulting in this scenario having the lowest total annual savings of all scenarios analysed in this set.

Set 1 Comparison Summary

The engine operational expenses were estimated to be $0.036 per kWh generated and the biogas compressor and dryer were estimated to draw 95 kW at the typical engine fuel rate of 143 scfm of biogas. Evaluating under these conditions, the savings generated while running the engine during the off-peak periods year-round are insufficient to offset the operational costs for the engine. As a result, it is recommended that Mesa NWWRP continue to operate the engine only during peak periods year-round, corresponding to a cumulative run time of 3,290 hours per year and an annual uptime of approximately 38%. This is understood to be representative of current engine operations and was set as the baseline for all future scenario analyses. The Set 1 scenarios are summarized in Table 26. Co-Generation without Mixed HSW organic slurry Addition Scenario Model ResultsTable 26 and Figure 17.

Table 26. Co-Generation without Mixed HSW organic slurry Addition Scenario Model Results

Scenario	Annualized Scenario Savings [$]	GHG Reduction [MT CO_2e]	Total Project Cap Ex	Diesel Gallon Equivalents/ Day
1.1. ‘Summer On-Peak Only’	($2,000)	(128)	$0	-
1.2. ‘Summer On/Shoulder-Peak’	$14,000	23	$0	-
1.3. ‘All Year On/Shoulder-Peak / ‘Enhanced Baseline’	$21,000	221	$0	-
1.4. ‘All Year On/Shoulder-Peak + Summer Off-Peak’	$1,000	522	$0	-
1.5. ‘All Year 24/7’	($32,000)	918	$0	-

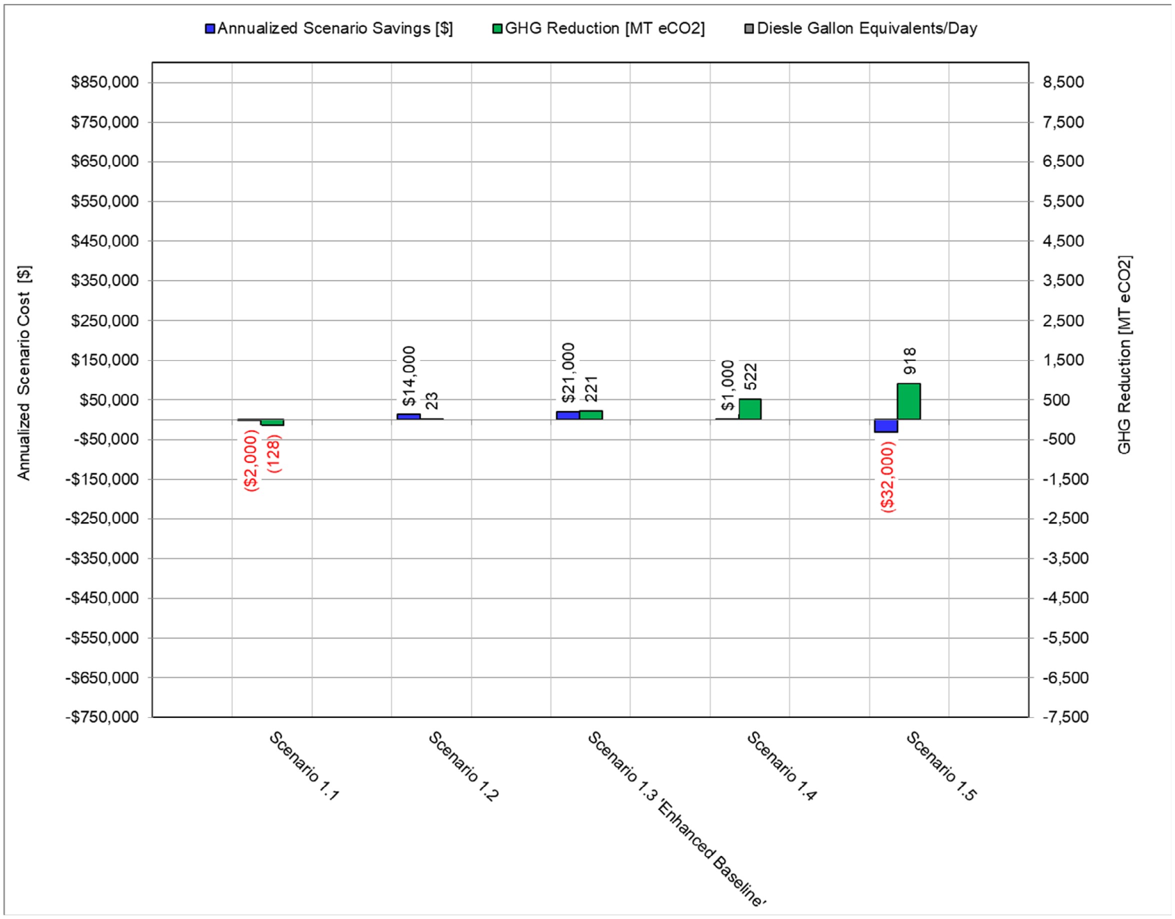


Figure 17. Co-Generation without Mixed HSW organic slurry Addition Scenario Comparison

6.2 Set 2: CHP engine with Mixed HSW Addition

Set 2 scenarios explore ways in which NWWRP may increase savings and reduce GHG emissions by accepting the mixed HSW organic slurry to the digester and maximizing biogas utilization with the existing co-generation operations. This would include a capital project to implement a Slurry Offloading and Receiving station as described in Section 4.2. In this set of scenarios, the mixed HSW organic slurry is added to either one digester or both digesters at the limiting 35% VS load mass fraction. Scenarios ‘CHP at 100%’ shows the theoretical performance that if NWWRP maximizes biogas usage to the engine to 100% of its rated input fuel capacity. All scenarios assume the current engine operations at only On-Peak and Shoulder Peak periods throughout the year would be maintained. A summary of the results of the Set 2 scenarios can be found below.

Scenario 2.1. ‘HSW to 1 DIG – ‘All Year On-/ Shoulder-Peak’ CHP at 87.5%’

Under this scenario, 22 tons per day (tpd) of OSW and 5,000 gallons per day (gpd) of FOG are sent to one digester and CHP is used to peak shave year-round during both on-peak and shoulder-peak periods. Therefore, NWWRP operates the engine during “Winter On-Peak” seasonal periods, as shown in Figure 16. 2018 Seasonal Electrical Power Costs

Table 25. Total biogas generation increases to 204 scfm with the addition of HSW from 132 scfm under the ‘Enhanced Baseline’ Scenario, equating to a 55% increase in biogas generation.

The additional biogas generation means that supplemental NG is negligible, with the CHP operating on biogas over 99% of its uptime. However, since the biogas flared during CHP downtime increases as well, biogas utilization under this scenario is 38%, the remaining 62% of biogas generated is flared. This scenario generates an annual savings of ($539,000) which is $560,000 lower than the baseline annual savings. The decrease in annual savings results from the fact that the scenario includes $732,000 per year in annualized capital costs associated with the pre-processing facility and equipment, and the savings generated from running the CHP on biogas for a greater proportion of its uptime is insufficient to offset these costs. The reduction in NG consumption in the CHP increases GHG reductions by 247 MT CO_2e per year over the baseline.

Scenario 2.2. ‘HSW to 1 DIG – CHP at 100%’

Under this scenario, the HSW feeding conditions are identical to those in scenario 2.1 at 22 tpd OSW and 5,000 gpd FOG and the cumulative biogas generation rate of 204 scfm. CHP is used to peak shave year-round during both on-peak and shoulder-peak periods. Therefore, NWWRP operates the engine during “Winter On-Peak” seasonal periods, as shown in Figure 16. 2018 Seasonal Electrical Power Costs

Table 25. CHP generation under this scenario is increased to the full rated engine capacity of 600 kW.

As a result, CHP biogas consumption increases to 239 scfm, however, the required supplemental NG to the CHP engine increases to approximately 15% of uptime, instead of the 1% of uptime in Scenario 2.1. Due to the increased biogas consumption during CHP uptime, the biogas utilization under this scenario increases relative to the 'Baseline' Scenario, 38% of biogas is utilized and the remaining 62% being flared. The annual savings in this scenario remains at ($539,000) and GHG reductions are slightly decreased compared to Scenario 2.1 due to the increased NG consumption, decreasing from 468 MT CO_2e per year to 450 MT CO_2e per year. As with Scenario 2.1, the annual savings are significantly lower than the baseline due to the $732,000 per year in annualized capital costs associated with the pre-processing facility and equipment.

Scenario 2.3. 'HSW to both DIGs – CHP at 87.5%'

Under this scenario, HSW loading rates are identical to Scenario 2.3 at 44 tpd OSW and 10,000 gpd FOG, with equal parts of the HSW slurry injected into each digester. CHP is used to peak shave during both peak and shoulder peak periods year-round. Therefore, NWWRP operates the engine during "Winter On-Peak" seasonal periods, as shown in Figure 16. 2018 Seasonal Electrical Power Costs

Table 25.

Biogas generation increases to 278 scfm, a 110% over the 'Enhanced Baseline' Scenario. CHP generation rates is set at 525 kW, or 87.5% load, and no supplemental NG is required by the CHP. The amount of biogas flared under this scenario increases to 81% with the remaining 19% being used in the CHP. The annual savings in this scenario remain negative at ($358,000), which represents a $181,000 increase in annual savings over scenarios 2.1 and 2.2. The $181,000 increase in annual savings under this scenario is primarily derived from increased OSW tipping fee offsets and FOG tipping fees. GHG reductions in this scenario decrease relative to scenarios 2.1 and 2.2 to 438 MT CO_2e due to the fact that a larger power draw is required for OSW pre-processing which is not offset by a similar increase in CHP generation since only 1 scfm of NG is being offset in this scenario with the remainder of the increased biogas generated being flared.

Scenario 2.4. 'HSW to both DIGs – CHP at 100%'

Under this scenario, HSW loading rates are identical to Scenario 2.3 at 44 tpd OSW and 10,000 gpd FOG, with equal parts of the HSW slurry injected into each digester. CHP is used to peak shave during both peak and shoulder peak periods year-round. Therefore, NWWRP operates the engine during "Winter On-Peak" seasonal periods, as shown in Figure 16. 2018 Seasonal Electrical Power Costs

Table 25.

Biogas generation increases to 278 scfm, a 110% over the ‘Enhanced Baseline’ Scenario. CHP generation is expanded to 600 kW, from the baseline generation of 525 kW to the full rated engine capacity with generation at Since biogas generation is 274 scfm, supplemental NG is not required for CHP in this scenario. This scenario generates ($349,000) in annual savings which represents a $190,000 increase in savings over Scenario 2.1, ‘Slurry to 1 DIG – CHP at 87.5%’, and Scenario 2.2, ‘Slurry to 1 DIG – CHP at 100%’ and a $10,000 increase in savings over Scenario 2.3 ‘Slurry to both DIGs – CHP at 87.5%’. Both the $10,000 increase in savings and 124 MT CO_2e increase in GHG reductions result from the increase in power generation under this scenario since all other parameters analysed remain identical.

Scenario 2.5. ‘HSW to both DIGs – Expanded CHP at 100%’

The 'HSW to both DIGs – Expanded CHP at 100%' Scenario assumes that the City will inject HSW slurry (organic solid waste from City and FOG from outside sources) in both digesters. This scenario assumes that, in addition to the existing 600 kW engine, NWWRP would install an additional 800 kW engine that uses 194 scfm biogas at its rated capacity and has a 38% electric efficiency compared to the current engine’s electric efficiency of 23%.

Previously, it had been communicated that an expansion to the CHP system would require an upgrade to the electrical distribution system because the NWWRP transmission grid has a maximum operating capacity of 525 kW. Following an investigation of the NWWRP transmission grid conducted by Arcadis, it was concluded that NWWRP’s transmission grid is currently set up to accommodate a second CHP engine and no upgrades to the transmission grid would be required to expand CHP capacity. However, it is important to highlight that, due to the much higher sensitivity of modern CHP engine units to fouling via H_2S and siloxanes in the biogas feed, biogas pre-treatment would be required if an additional CHP engine is installed, incurring $200,000 in added capital cost under this scenario.

The City’s expanded engine generator system generates electricity both on-peak and shoulder-peak periods, all year around. Therefore, NWWRP operates the engine during “Winter On-Peak” seasonal periods, as shown in Table 28. The biogas is used as it is generated and supplemented with biogas stored in the existing storage tank to operate the engines. Natural gas is fed to the engine when biogas in not available (while the storage tank is being filled). It is assumed that the engines have a 90% annual availability.

Under this scenario, the loading rates were set at 44 tpd of OSW and 10,000 gpd of FOG, with half the total load being sent to each digester. Biogas generation increases to 278 scfm, a 110% over the ‘Enhanced Baseline’ Scenario. Both engines are operated at their full rated capacity of 600 kW and 800 kW for a total power generation of 1.4 MW. The existing CHP engine is entirely fuelled on biogas and the additional CHP engine is fuelled by biogas for 20% of its uptime and NG for the remainder of its uptime. The annual savings under this scenario are ($336,500), which is the highest annual savings of the scenarios analysed in this scenario set. GHG reductions are considerably higher than in Scenarios 2.1 through 2.4 at 1,303 MT CO_2e with the second highest reduction at 562 MT CO_2e because power generation is more than doubled under this scenario.

Set 2 Comparison Summary

From the results of this analysis, it appears that accepting HSW and using the additional biogas in the current CHP system is not economically beneficial. The high capital costs associated with the pre-processing facility and equipment for the OSW and the FOG processing coupled with the fact that, while the increase biogas generation rates generated from HSW reduce or eliminate the need to supplement NG to the CHP, operationally motivated CHP downtime during off-peak periods still results in a significant proportion of biogas being flared, meaning that the increase in biogas production is not being leveraged for significant economic benefit.

At increasing rates of HSW acceptance, economics improve primarily due to the tipping fee and tipping fee offsets and marginally from the increase in biogas generation. It is important to highlight that the economics of accepting OSW are highly dependent upon the tipping fees of $30.31 per wet ton. The Set 2 scenarios are summarized in Table 27 and Figure 18.

Table 27. CHP engine with Mixed HSW organic slurry Addition Scenario Estimates

Scenario	Annualized Scenario Savings [$]	GHG Reduction [MT CO_2e]	Total Project Capital Expenditure	Diesel Gallon Equivalent/ Day
1.3. ‘Enhanced Baseline’	$21,000	221	$0	-
2.1. ‘Slurry to 1 DIG – CHP at 87.5%’	($539,000)	468	$10,895,800	-
2.2. ‘Slurry to 1 DIG – CHP at 100%’	($539,000)	450	$10,895,800	-
2.3. ‘Slurry to both DIGs – CHP at 87.5%’	($358,000)	440	$10,895,800	-
2.4. ‘Slurry to both DIGs – CHP at 100%’	($349,000)	562	$10,895,800	-
2.5 ‘Slurry to both DIGs – Expanded CHP’	($336,500)	1,303	$12,220,800	-

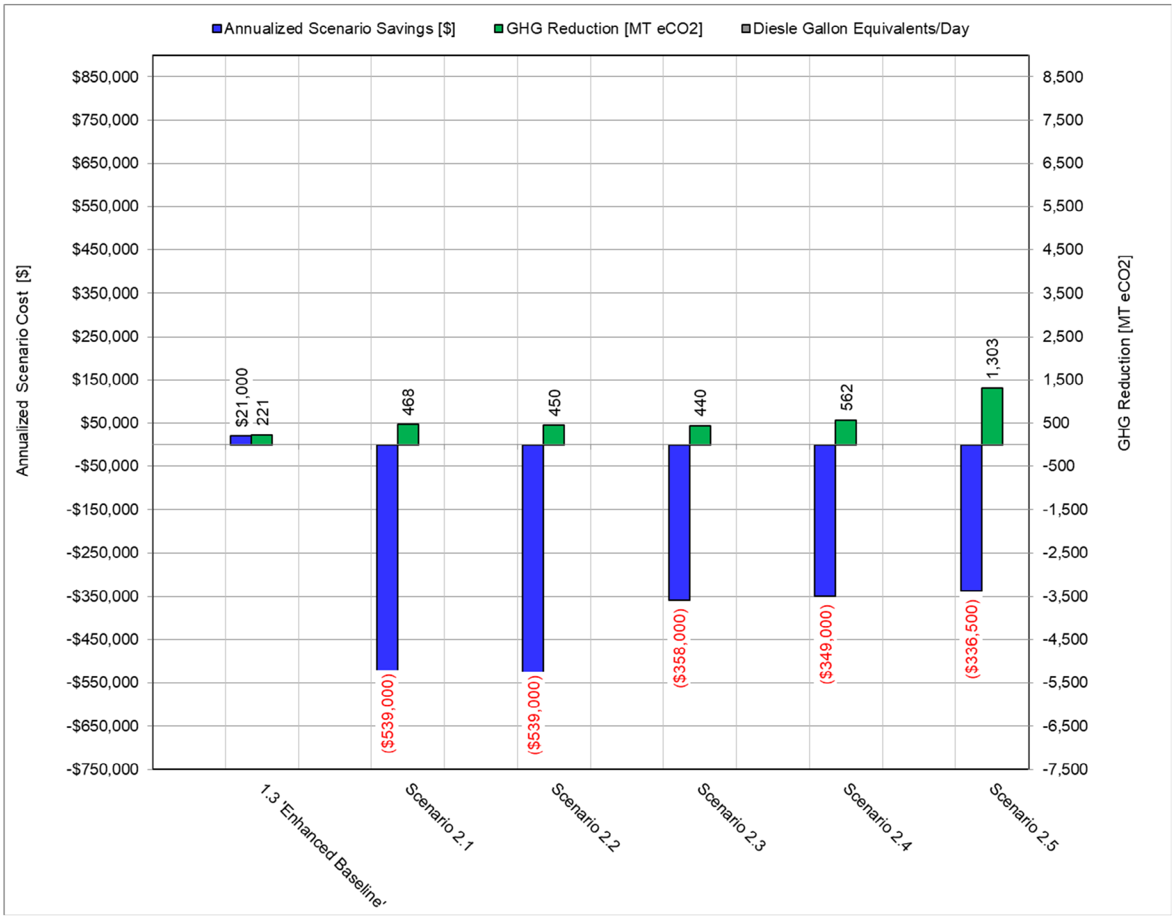


Figure 18. CHP engine with Mixed HSW organic slurry Addition Scenario Comparison

Set 2 Conclusions

From the results of this analysis, it appears that accepting HSW and using the additional biogas in the current CHP system is not economically beneficial. The high capital costs associated with the pre-processing facility and equipment for the OSW and the FOG processing coupled with the fact that, while the increase biogas generation rates generated from HSW reduce or eliminate the need to supplement NG to the CHP, operationally motivated CHP downtime during off-peak periods still results in a significant proportion of biogas being flared, meaning that the increase in biogas production is not being leveraged for significant economic benefit.

At increasing rates of HSW acceptance, economics improve primarily due to the tipping fee and tipping fee offsets and marginally from the increase in biogas generation. It is important to highlight that the economics of accepting OSW are highly dependent upon the tipping fees offset of $30.31 per wet ton.

6.3 Set 3: RNG Generation with Mixed HSW Addition

Set 3 scenarios explore ways in which NWWRP can increase savings and GHG reduce emissions by accepting OSW and FOG and maximizing biogas utilization by generating renewable natural gas (RNG). This would involve a capital project to install an RNG upgrading system as described in Section 4.3. The scenarios also include potential benefits of generating RIN credits and offsetting Sanitation CNG vehicle fuel costs.

All six scenarios explore the potential benefits of adding varying the mixed HSW organic slurry to one, both, or neither of the digesters. Scenarios 3.2 and 3.4 present the ideal future condition demonstrating the theoretical change in the process in which D3 and D5 RIN credits are distributed based on mass fraction of organic waste loaded to the digester as detailed in 'Biogas Utilization & Project Incentives' Memorandum. The current RFS stipulates if any amount of HSW is added to a digester, then all biogas produced becomes classified as eligible for D5 RINs. As the concept of distinguishing D3 and D5 RIN credits based on a mass ratio of organic waste to sludge in a digester is developed, the conceivable annualized savings increase significantly. These two 'D3/D5 Mass Fraction' scenarios are considered in order to demonstrate the annual revenue achievable under the anticipated future conditions. Recently, RIN credit values have decreased significantly from their 2017 peak values making RIN credit volatility an important factor to consider when evaluating future RIN revenue potential. Based on discussion with policy and market experts, a D3 RIN value of $1.85 per RIN and a D5 RIN value of $0.34 per RIN was selected as a long-term planning value on which to base the scenario analyses.

Lastly, Scenarios 3.5 and 3.6 evaluate the effects generating RNG with no HSW addition. The scenarios show the theoretical benefits of generating RNG solely from current sludge flow and from implementing the Pondus system to hydrolyze the thickened WAS at the Plant. The annual savings under both scenarios do not account for the capital and O&M expenditure of an offloading and receiving station. However, these scenarios do not generate any income from tipping fees.

Subsequent sections describe the scenario parameters in greater detail. A summary of the results of the Set 3 scenarios can be found below.

Scenario 3.1A 'HSW to 1 DIG – D3/D5 RNG + Membrane Upgrading Skid

The 'HSW to both DIGs – D3 and D5 RNG' Scenario assumes that the City will inject HSW slurry (organic solid waste from City and FOG from outside sources) into one digester. This scenario assumes that City sends all available biogas to the generation of renewable natural gas (RNG). It is assumed that the membrane system has a 95% annual availability. Since HSW is added to one digester, this scenario generates both D3 (non-HSW digester) and D5 (w/HSW digester) RIN credits. The analysis accounts for diesel fuel offset by generating compressed natural gas (CNG). Under this scenario, the engine generator system is not operated.

Under this scenario, 22 tpd of hauled OSW and 5,000 gpd of FOG are being sent to a single digester. All biogas is sent to the membrane upgrading system to generate both D3 and D5 RINs, yielding a total of approximately $568,000 in RIN credits. In addition to RIN revenues, tipping fee offsets from OSW generate $118,000 per year in avoided costs and FOG tipping revenues are $26,000 per year. The $14,830,800 in capital expenditures under this scenario includes expenditures necessary for the waste pre-processing facility, pre-processing equipment, organic waste receiving at NWWRP, the membrane upgrading system, a thermal oxidizer system for tail gas treatment and transmission of RNG to the NG transmission pipeline.

Under these conditions, NWWRP is expected to generate approximately 1,362 diesel gallon equivalents (DGE) per day. This DGE represents 79% of the current CNG fleet demand in Mesa and is expected to offset approximately $229,000 in fuel costs per year. GHG reductions for this scenario are 3,507 MT CO_2e due to the substantial vehicle fuel offsets generated under this scenario.

Scenario 3.1B ‘HSW to 1 DIG – D3/D5 RNG + PSA Upgrading Skid

The 'HSW to both DIGs – D3 and D5 RNG' Scenario assumes that the City will inject HSW slurry (organic solid waste from City and FOG from outside sources) into one digester. This scenario assumes that City sends all available biogas to the generation of renewable natural gas (RNG). It is assumed that the PSA system has a 95% annual availability. Since HSW is added to one digester, this scenario generates both D3 (non-HSW digester) and D5 (w/HSW digester) RIN credits. The analysis accounts for diesel fuel offset by generating compressed natural gas (CNG). Under this scenario, the engine generator system is not operated.

Under this scenario, 22 tpd of hauled OSW (approx. 3,200 gpd) and 5,000 gpd of FOG are being sent to a single digester. All biogas is sent to the membrane upgrading system to generate both D3 and D5 RINs, yielding approximately $539,000 in RIN credits. In addition to RIN revenues, tipping fee offsets from OSW generate $118,000 per year in avoided costs and FOG tipping revenues are $26,000 per year. The $14,213,800 in capital expenditures under this scenario includes expenditures necessary for the waste pre-processing facility, pre-processing equipment, organic waste receiving at NWWRP, the PSA upgrading system, a thermal oxidizer system for tail gas treatment and transmission of RNG to the NG transmission pipeline. This capital expenditure is lower compared the capital expenditure under Scenario 3.1A due to the lower capital cost associated with a PSA system compared to a membrane system,

Under these conditions, NWWRP is expected to generate approximately 1,291 diesel gallon equivalents (DGE) per day; this value is lower than the DGE generation under Scenario 3.1A because the membrane system has a higher methane capture at 97% versus 92% for the PSA system. This DGE represents 75% of the current CNG fleet demand in Mesa and is expected to offset approximately $217,000 in fuel costs per year. GHG reductions for this scenario are lower than those under Scenario 3.1A at 3,333 MT CO_2e versus 3,507 MT CO_2e because the PSA system generates slightly less vehicle fuel compared to the membrane system and has a higher power draw than the membrane system.

However, despite these factors, the PSA system increases annual savings by $84,000 over Scenario 3.1A indicating that the PSA is a more economically favourable RNG upgrading technology than the membrane system. As a result, all subsequent analyses involving RNG generation are modelled using a PSA system.

Scenario 3.2 'HSW to 1 DIG – D3/D5 RNG Mass Fraction' Scenario

This scenario evaluates the benefits if the EPA adjust the RIN credit distribution on a mass ratio of organic waste to sludge into a single digester. The maximum waste accepted under this scenario is 22 tpd of hauled OSW (approx. 3,200 gpd) and 5,000 gpd of FOG.

Therefore, this scenario reflects the potential benefit of sending the maximum amount of D3 RIN biogas and D5 RIN biogas to generate RNG by accepting waste into only one digester. If NWWRP dedicates one digester to co-digestion and one digester to digesting sludge only. All D3 and D5 RIN biogas would be sent directly to the RNG system, generating approximately $983,000/year in RIN credits. This represents a $444,000 increase in RIN revenue relative to Scenario 3.1B and generates a positive savings of $199,000 per year or $178,000 savings over the baseline.

Scenario 3.3 'HSW to both DIGs – All D5 RNG' Scenario

The 'HSW to both DIGs – All D5 RNG' Scenario assumes that the City will inject HSW slurry (organic solid waste from City and FOG from outside sources) in both digesters. This scenario assumes that City sends all available biogas to the generation of renewable natural gas (RNG). It is assumed that the RNG system has a 95% annual availability. Since HSW is added to both digesters, this scenario generates only D5 RIN credits. The analysis accounts for diesel fuel offset by generating compressed natural gas (CNG). Under this scenario, the engine generator system is not operated.

The maximum waste accepted under this scenario is 44 tpd of hauled OSW (approx. 6,400 gpd) and 10,000 gpd of FOG. Sending the maximum amount of D5 RIN biogas to generate RNG would generate approximately $299,000 from RIN credits. Under these conditions, NWWRP is expected to generate approximately 1,722 DGE per day. This DGE represents 100% of the current CNG fleet demand in Mesa and offsetting $289,000 in fuel costs per year. Despite the fact that vehicle fuel generation under this scenario is 33% higher than in Scenario 3.1B, due to the lower value of D5 RINs, RIN credit revenue decreases by $240,000 therefore; the primary financial benefits of accepting additional HSW and generating additional vehicle fuel comes from OSW tipping fee offsets, FOG tipping fees and CNG fuel cost offsets. Annual savings under this scenario increase by $12,000 per year to ($233,000), however, this value is highly dependent upon the OSW tipping fee of $30.31 per wet ton and if the tipping fee were to increase in the future, annual savings would further improve.

Scenario 3.4 'HSW to both DIGs – D3/D5 Mass Fraction' Scenario

This scenario evaluates the benefits if the EPA adjusted the RIN credit distribution on a mass ratio of organic waste to sludge into both digesters. The maximum waste accepted under this scenario is 44 tpd of hauled OSW (approx. 6,400 gpd) and 10,000 gpd of FOG.

This scenario reflects the potential benefit of diverting the maximum amount of organic waste from landfills. This scenario reflects the potential benefit of sending the maximum amount of D3 RIN biogas and D5 RIN biogas to generate RNG by accepting waste into both digesters. If NWWRP dedicates one digester to co-digestion and one digester to digesting sludge only. It is estimated that equal amount of sludge be sent to both digesters to maximize the organic mass fraction. All D3 and D5 RIN biogas would be sent directly to the RNG system, generating approximately $1,165,000 in RIN credits per year, which is an $866,000 increase in RIN revenue over scenario 3.4. DGE generation rates remain unchanged from scenario 3.3 at 1,792 DGE per day, generating $289,000 in fuel cost offsets per year. Annual savings under this scenario are positive at $633,000 per year which represents a $612,000 increase in savings over the baseline.

Scenario 3.5 ‘No HSW – All D3 RNG’ Scenario

This scenario reflects the potential benefit of sending the maximum amount of D3 RIN biogas to generate RNG by not accepting any organic waste. The capital expenditures under this scenario are $10,895,800 lower than in Scenarios 3.1B through 3.4 since this configuration does not require a pre-processing facility or pre-processing equipment. The $3,318,000 capital expenditure required under this scenario includes the capital expenditure for the PSA upgrading system, thermal oxidizer for tail gas treatment and transmission of the RNG product gas to the NG transmission pipeline.

Under this scenario, all biogas would be sent directly to the RNG system, generating approximately $772,000 in RIN credits per year, which is the highest RIN revenue potential of all scenarios not involving a D3/D5 mass fraction split. Under these conditions, NWWRP is expected to generate approximately 818 DGE per day, meaning this scenario yields the lowest CNG fleet demand offset at approximately 48% of the current demand. This offset generates approximately $138,000 per year in fuel cost savings.

Of the scenarios analysed, this scenario generates the highest annual savings without assuming a D3/D5 mass fraction split at $497,000 per year, which represents a $456,000 increase in annual savings over the baseline. The increased annual savings under this scenario primarily result from the elimination of the capital costs associated with the organic waste pre-processing facility and equipment in addition to the fact that RIN revenues are higher under this scenario since all RNG generated qualifies for D3 RIN credits. Additionally, since this scenario does not require a pre-processing facility, this scenario would have a greatly accelerated timeline for completion relative to any scenarios involving organic waste acceptance.

Scenario 3.6 ‘No HSW – All D3 RNG + Pondus’ Scenario

This scenario reflects the potential benefit of using Pondus to increase WAS degradability and leveraging the increase in biogas generation to increase D3 RIN revenue. Additionally, Pondus decreases the amount of biosolids generated, decreasing sludge hauling costs. No organic waste is accepted under this scenario, all biogas is converted to RNG and D3 RINs are exclusively generated. D3 RIN revenues under this scenario are $862,000 per year, a $90,000 increase in RIN revenue over Scenario 3.5. Under these conditions, NWWRP is expected to generate approximately 913 DGE per year. This DGE represents 53% of the current CNG fleet demand in Mesa and is expected to offset $153,000 per year.

Despite the increase in biogas generated and D3 RIN revenue collected, the annual savings under this scenario are $156,000 lower than under Scenario 3.5 due to the $3,630,000 in additional capital expenditures for the Pondus system under this scenario.

Set 3 Comparison Summary

The Set 3 scenarios are summarized in Table 28 and Figure 19.

Table 28. RNG Generation with Mixed HSW organic slurry Addition Scenario Estimates

Scenario	Annualized Scenario Savings [$]	GHG Reduction [MT CO_2e]	Total Project Capital Expenditure	Diesel Gallon Equivalents/ Day
1.3. ‘Enhanced Baseline’	$21,000	221	$0	-
3.1A ‘Slurry to 1 DIG, D3/D5, Membrane’	($329,000)	3,507	$14,830,800	1,362
3.1B ‘Slurry to 1 DIG, D3/D5, PSA’	($245,000)	3,333	$14,213,800	1,291
3.2 ‘Slurry to 1 DIG, D3/D5 Mass Fraction’	$199,000	3,333	$14,213,800	1,291
3.3 ‘Slurry to both DIGs, all D5’	($233,000)	4,886	$14,213,800	1,722
3.4 ‘Slurry to both DIGs, D3/D5 Mass Fraction’	$633,000	4,886	$14,213,800	1,722
3.5 ‘No Slurry, all D3’	$497,000	1,709	$3,318,000	818
3.6 ‘No Slurry, all D3 + Pondus’	$341,000	1,847	$5,217,600	913

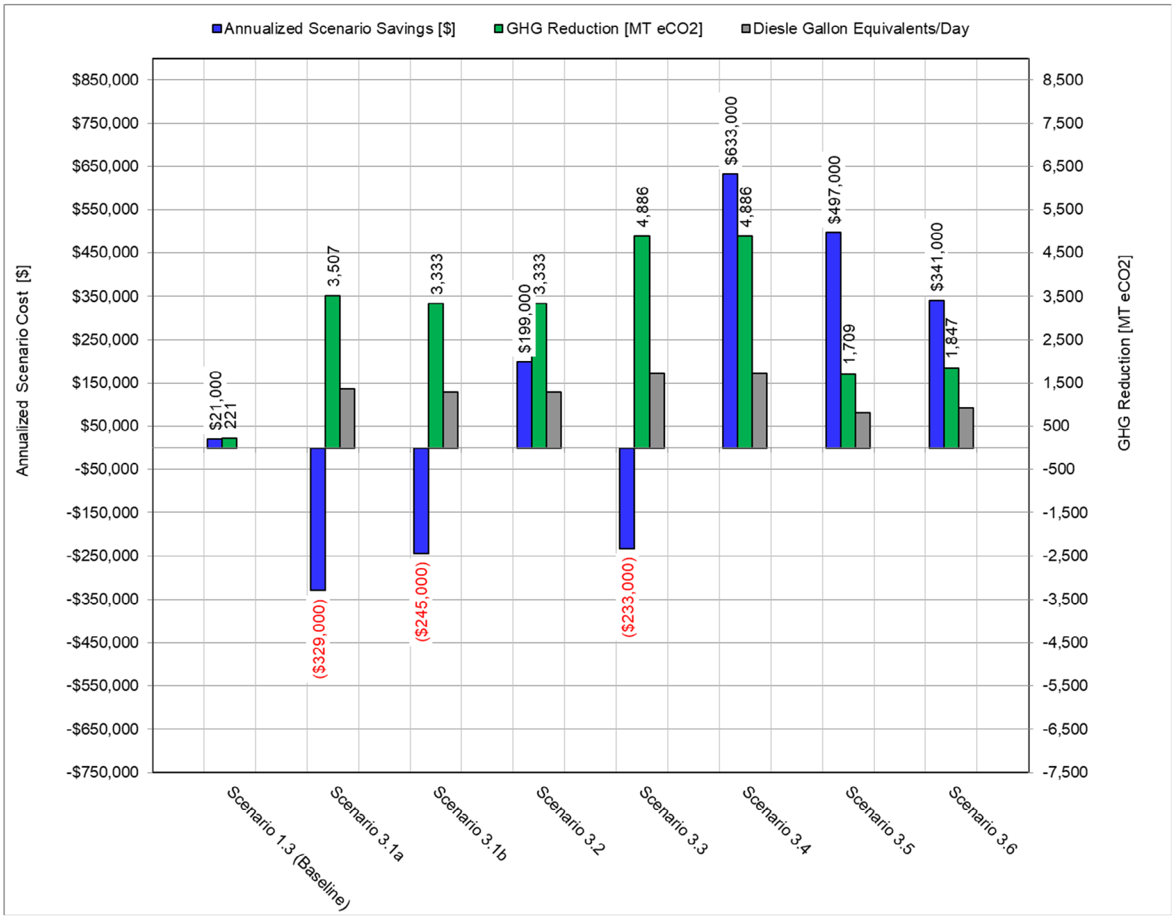


Figure 19. RNG Generation with Mixed HSW organic slurry Addition Scenario Comparison

Set 3 Conclusion

From the results of this analysis, it appears that accepting mixed HSW organic slurry into one digester (Scenario 3.1B) generates annualized savings 5% higher than accepting mixed HSW organic slurry into both digesters (Scenario 3.3). Scenario 3.5, accepting no mixed HSW organic slurry generated the highest yielding annualized savings of $497,000, a $730,000 increase in annual savings relative to accepting mixed HSW organic slurry into both digesters (Scenario 3.3). While there is a substantial difference between D3 and D5 RIN credit values, the economic benefits associated with tipping fees, tipping fee offsets and increased vehicle fuel cost offsets contribute to improving the economics of D5 RINs; the primary factor resulting in the significant decrease in annual savings over the baseline are largely attributed to the significant costs associated with amortizing the capital expenditures for the OSW pre-processing facility and equipment.

The Set 3 evaluation indicates the most cost-effective configuration is to generate RNG from the existing biogas generated at the Plant without any slurry addition because the ‘No Mixed HSW organic slurry’ (Scenario 3.6). In addition to being the most economically favorable scenario, this configuration would have the shortest timeline for implementation since it does not require the construction of an organics pre-processing facility.

A significant increase in the projected annual savings is projected if D3 and D5 RINs could be assigned based on a mass loading faction basis. This would require specific BMP testing of all accepted feedstocks and would be a significant step in adjusting the EPA valuation of biogas from mixed OSW and FOG and sludge digesters

Lastly, the Scenario 3.6 indicates that operating the Pondus system at NWWRP is not financially beneficial. The increased RIN revenue and decreased sludge hauling costs Pondus generates are insufficient to offset the capital and O&M expenditure associated with the Pondus system.

6.4 Set 4: Co-Generation and RNG Generation with Mixed HSW Addition

Set 4 scenarios explore ways in which NWWRP can increase savings and reduce GHG emissions by accepting mixed HSW organic slurry and maximizing biogas utilization to renewable natural gas (RNG) generation and enhancing the existing co-generation operations. Subsequent sections describe the scenario parameters in greater detail. A summary of the results of the Set 4 scenarios can be found below.

Scenario 4.1 ‘HSW to 1 DIG – Existing CHP + RNG’ Scenario

This scenario evaluates the potential benefit of sending the maximum amount of D3 RIN biogas to generate RNG and a portion of the D5 RIN biogas to the CHP engine. 22 tpd of OSW and 10,000 gpd of FOG accepted to a single digester under this scenario. 100% of the biogas from the digester receiving mixed HSW organic slurry is sent to the CHP during peak periods with natural gas being supplemented when biogas availability falls below the minimum engine turndown of 70%. It is important to highlight that under this configuration, the most economically beneficial option is no longer to run the CHP during peak and shoulder peak periods year round; the maximum annual savings occur when biogas is used to generate D5 RINs instead of power during all periods except for the ‘Max Summer On-Peak’ period. Therefore, for this analysis, CHP is only operational during the ‘Max Summer On-Peak’ period and when the CHP is operational, it is assumed that it is run at its full rated capacity of 600 kW. The existing 80 psig liquid ring compressor and pressure storage vessel remain in use under this scenario.

The second digester would be dedicated to digesting sludge only, and all D3 RIN biogas would be sent directly to the RNG system even during CHP uptime. When the engine is not in operation, the D5 RIN biogas from the co-digestion digester is sent to the RNG system. Under these conditions, total RIN revenues are $533,000 per year and 1,258 DGE per day are generated. This DGE generation rate represents 73% of the current CNG fleet demand in Mesa and would offset $211,000 per year in fuel costs.

Compared to Scenario 3.1B ‘Slurry to 1 digester, D3/D5, PSA, operating CHP on biogas during ‘Max Summer On-Peak’ periods increased annual savings by $2,000 per year to ($243,000) per year.

Scenario 4.2 'HSW to 1 DIG – Low Pressure CHP + RNG' Scenario

This scenario reflects the potential benefit of replacing the current 80 psig liquid ring compressor with a 1.5 psig blower system to reduce the power draw of the CHP biogas feed system. The model parameters for the two options are summarized in Table 29.

Table 29. Low Pressure Biogas Feed System Parameters

Parameter	Existing Biogas Feed System	Low Pressure Biogas Feed System	Unit
Capital Expenditure	$0	$510,000	USD
Power Draw	72	19	kW

Digestion parameters are identical to Scenario 4.1, with 22 tpd of OSW and 5,000 gpd of FOG being accepted to a single digester. CHP is only operated on biogas during 'Max Summer On-Peak' periods and is operated at its full rated capacity of 600 kW. When the engine is not in operation, the D5 RIN biogas from the co-digestion digester is sent to the RNG system.

Under these conditions, total RIN revenues remain at $533,000 per year and 73% of the current CNG fleet demand in Mesa is offset, generating $211,000 in fuel cost savings per year. Annual savings under this scenario decrease by $39,000 relative to Scenario 4.1, indicating that the reduction in parasitic power draw for the biogas feed system is insufficient to offset the increased capital cost associated with the 1.5 psig blowers.

Scenario 4.3 'HSW to both DIGs – Existing P CHP + RNG' Scenario

The 'HSW to both DIGs – Existing P CHP + RNG' Scenario assumes that the City will inject HSW slurry (organic solid waste from City and FOG from outside sources) in both digesters. This scenario assumes that City primarily generates RNG and uses a portion of the biogas in its CHP system to peak shave. CHP is only operated on biogas during the 'Max Summer On-Peak' seasonal period and is operated at its full rated capacity of 600 kW during operation. Since HSW is added to both digesters, this scenario generates only D5 RIN credits. The existing 80 psig liquid ring compressor and pressure storage vessel remain in use under this scenario.

When the engine is not in operation, all D5 RIN biogas from the co-digestion digester is sent to the RNG system, generating approximately $289,000 in RIN credits. Under these conditions, NWWRP is expected to generate approximately 1,665 DGE per day. This DGE represents 97% of the current CNG fleet demand in Mesa, offsetting $280,000 per year in fuel costs.

Compared to injecting the mixed HSW organic slurry into a single digester under Scenario 4.1, co-digesting in both digesters and using D5 RINs to fuel the existing CHP system increases annual savings by $7,000 due to the increase in savings generated from increased tipping fee and vehicle fuel offsets. However, relative to Scenario 3.4 'Slurry to both digesters, D3/D5 Mass Fraction' the annual savings under this scenario decrease by $3,000 per year. Since under this scenario, no NG is supplemented to the CHP, the results of this scenario indicate that D5 RNG is more lucrative when used to collect RIN credits than when used in the CHP engine.

Scenario 4.4. 'HSW to both DIGs – Low P CHP + RNG' Scenario

Under this scenario, the co-digestion parameters set under Scenario 4.3 are retained, RNG and CHP operation remain unchanged and the biogas feed system is upgraded to the low-pressure feed system analyzed in Scenario 4.2. The annual savings under this scenario decrease by $37,000 relative to Scenario 4.3, re-iterating the findings in Scenario 4.2.

Scenario 4.5. 'No HSW – all D3 RNG + NG Peak CHP' Scenario

The 'No HSW – all D3 RNG + NG Peak CHP' Scenario assumes that the City will not collect, process, or inject any HSW at NWWRP. This scenario assumes that City sends all available biogas to the generation of renewable natural gas (RNG). It is assumed that the RNG system has a 95% annual availability. Since HSW is not added to either digester, this scenario generates only D3 RIN credits. The analysis accounts for diesel fuel offset by generating compressed natural gas (CNG).

Under this scenario, the City uses natural gas to run the City's existing engine generator system to generate electricity on-site; for this scenario, the maximum annual savings occur when the CHP engine is run during 'Mild Summer Shoulder-Peak" seasonal periods, as shown in Table 28. Therefore, this scenario was analyzed assuming CHP is operational during max and mild summer on-peak and shoulder-peak periods. Natural gas fed to the engine to operate at its full rated capacity of 600 kW. It is assumed that the engine has a 90% annual availability.

The annual savings under this scenario increase by $15,000 relative to Scenario 3.6, 'No-Slurry - all D3 RNG' indicating that it is most financially beneficial to operate the CHP on NG to peak shave during peak and shoulder peak during the summer. Of all scenarios evaluated without assuming a D3/D5 mass fraction RIN split, this scenario generates the highest annual savings at $512,000 per year, which represents a $491,000 increase in savings over the baseline scenario.

Set 4 Comparison Summary

The set 4 Scenario analyses are summarized in Table 30 and Figure 20.

Table 30. Co-Generation and RNG Generation with Mixed HSW organic slurry Addition Scenario Estimates

Scenario	Annualized Scenario Savings [$]	GHG Reduction [MT CO_2e]	Total Project Cap Ex	Diesel Gallon Equivalents/ Day
1.3. ‘Enhanced Baseline’	$21,000	221	$0	-
3.5. ‘No Slurry – all D3 RNG’	$497,000	1,709	$3,318,000	818
4.1. ‘Slurry to 1 DIG – Existing P CHP + RNG’	($243,000)	3,270	$14,213,800	1,258
4.2. ‘Slurry to 1 DIG - Low P CHP + RNG’	($282,000)	3,281	$14,823,800	1,258
4.3. ‘Slurry to both DIGs – Existing P CHP + RNG’	($236,000)	4,789	$14,213,800	1,665
4.4. ‘Slurry to both DIGs – Low P CHP + RNG’	($273,000)	4,811	$14,823,800	1,665
4.5. ‘No Slurry – all D3 RNG + NG Summer Peak CHP’	$512,000	1,622	$3,318,000	818

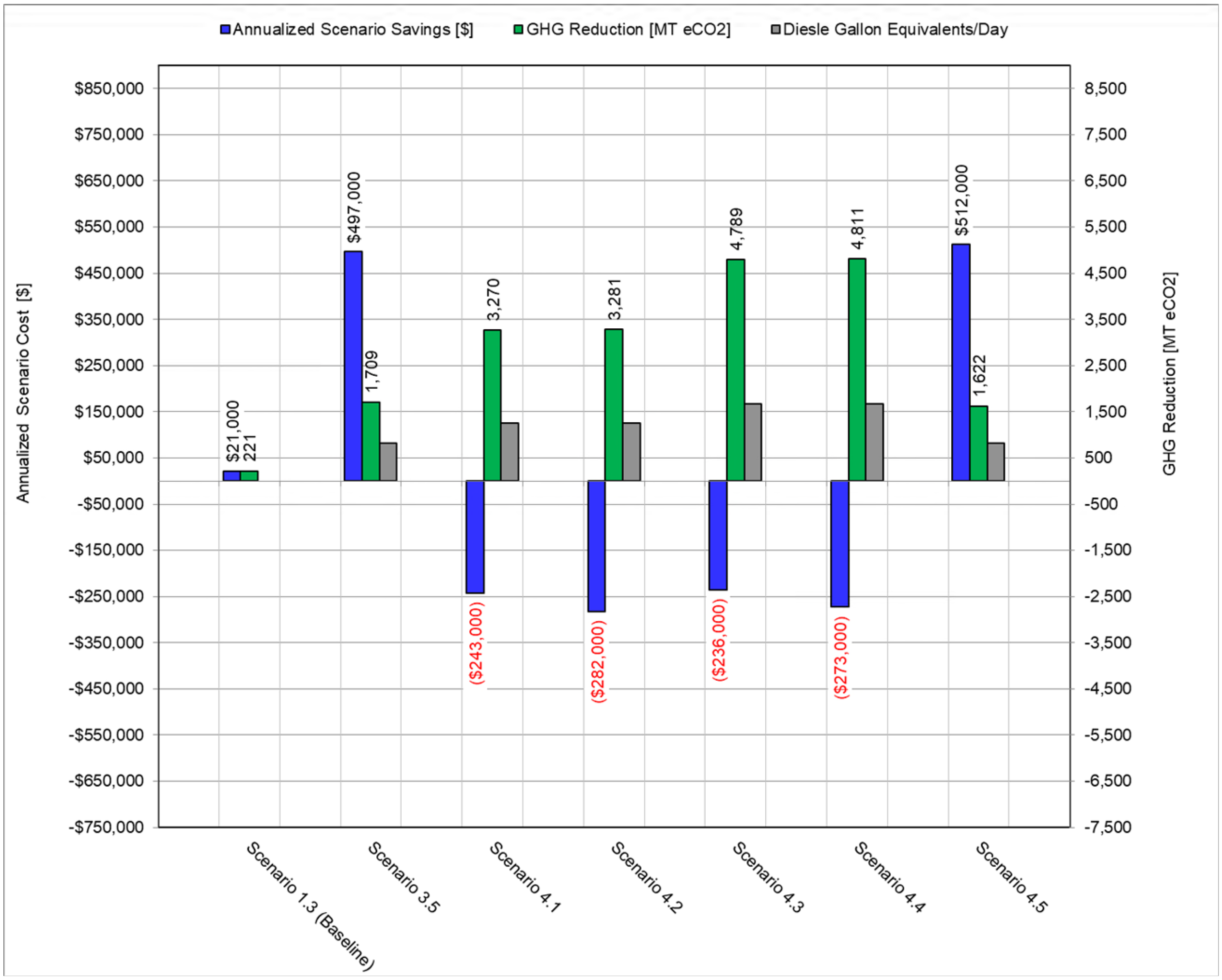


Figure 20. Co-generation and RNG Generation with Mixed HSW organic slurry Addition Scenario Comparison

Set 4 Conclusions

The results of this analysis indicate that it is not economical to divert biogas from the RNG system to the CHP during peak power periods. Operating a new low-pressure gas feed to the engine does not improve annual saving, because the annualized capital expenditures for low pressure feed system exceed the savings generated by the reduction in power draw.

As a result, it is recommended that the CHP exclusively be fuelled with NG and all available biogas be used to generate RNG. NG is preferable to biogas as fuel to the CHP due to the fact that D5 RIN credits are more valuable than offsetting power even at ‘Max Summer On-Peak’ periods and utilization of NG avoids the power draw and O&M associated with the biogas drying and compression. The CHP could be maintained as NG peak shaving process for as long as the engine equipment life allows.

6.5 Set 5: Participation in the Low Carbon Fuel Standard (LCFS) Program

In addition to RIN credits under the RFS, Mesa could qualify for The Low Carbon Fuel Standard (LCFS) by sending RNG to a California based fleet end user. The LCFS was designed as a performance-based regulation, such that the program incentivizes production and use of low-carbon transportation fuels based on a given fuel's lifecycle GHG emissions per unit of energy—or carbon intensity (CI) as rated by the California Air Resources Board (CARB). Carbon intensity is measured as grams of CO_2e per megajoule (MJ) of energy and one LCFS credit is generated for every metric ton of reduction of CO_2e emissions

Under the program, RNG derived from wastewater biogas is an ultra-low-carbon fuel option with relatively low CI values that will differ from plant to plant but will typically range from the low forties to single digits. For example, one California WWTP produces RNG with a CI of 7.75 (per CARB's fuel pathways table) while a second California plant is producing RNG with a CI of 30.92, which translates to LCFS credit values ranging from $17.32 per mmBtu to $12.80 per mmBtu respectively when using the August, 2019 LCFS credit value of $190. For the purpose of this analysis, Mesa's CI was conservatively estimated at 30, translating to $12.86 in LCFS credits per mmBtu of RNG generated. It is important to highlight that in order to qualify for the LCFS, the RNG must be injected into a pipeline with a theoretical physical pathway to the California based end user. As a result, if the Riverview pipeline is not physically connected to a pipeline leading to the California based end user, an alternate pipeline interconnection would be required, increasing the capital expenditure required under this option.

Scenario 5.1 'No Slurry – all D3 RNG and LCFS' Scenario

It was estimated that RIN revenue retained decreases from approximately 85% to 65%. Retained RIN revenue decreases since Mesa would no longer be providing its own CNG fleet as an end user, thus necessitating the involvement of both a RIN and LCFS broker to identify and arrange an offtake agreement with a California based CNG fleet. These additional responsibilities increase the broker's RIN revenue cut, and it is estimated that as little as 50-60% of the LCFS credit revenue would be retained by Mesa in addition to $30,000 per year in annual compliance costs to participate in the CA LCFS program. Nonetheless, doing so would result in an incremental value of $6.43 per mmBtu of RNG. Additionally, accessing the California market is projected to require offering very competitive pricing on the base RNG heating value; therefore, it is assumed that the end user CNG fleet would purchase the RNG for an average $0.40 per DGE, or 13% below the City's current average CNG costs.

Using these parameters, under the all D3 RIN scenario, generating LCFS credits increases annual savings by $35,000 per year over scenario 3.5 'No Slurry – all D3 RNG' to $532,000, representing a $511,000 increase in annual savings over the baseline.

Scenario 5.2 ‘Slurry to both DIGs – all D5 RNG and LCFS’ Scenario

When co-digesting 44 tpd OSW and 10,000 gpd FOG, generating LCFS credits increases annual savings by $338,000 over 3.3 ‘Slurry to both DIGs - all D5 RNG’. The more favorable economics of generating LCFS credits when co-digesting are largely due to the fact that LCFS credits do not decrease in value when co-digesting in a similar fashion to RIN credits.

As a result, approximately $242,000 per year in revenue is generated from D5 RIN credits whereas $590,000 per year in revenue is generated from LCFS credits. Therefore, when co-digesting, the LCFS better allows NWWRP to scale its RNG revenue than the RFS.

Set 5 Conclusions

When co-digesting, participating in the LCFS is more economically favorable than participating solely in the RFS program. However, the methodology for calculating LCFS credit values for different fuels introduces competitive disadvantages that may hinder the long-term prospects for accessing the LCFS credit market as a producer of wastewater biogas. More specifically, because dairy gas often has highly net-negative CI values, RNG from dairy gas (and other agricultural feedstocks) is considerably more valuable than wastewater biogas under the California program.

While dairy biogas currently accounts for less than 5% of the LCFS market, expansion of dairy RNG production in California and across the US likely means that the window for getting wastewater biogas into California is 4-5 years or less, ultimately meaning that Mesa will likely not be able to begin co-digesting quickly enough to profitably generate LCFS credits. In addition, the California natural gas vehicle market is nearing saturation as close to 95% of the CNG/LNG vehicles operating in the state already use RNG. Much of this RNG is still coming from out-of-state landfills with higher CI scores but accessing the CA market will soon require producers to displace landfill RNG by offering very competitive pricing.

Due to the additional annual savings potential participation in the LCFS can yield, it is recommended that Mesa investigate the possibility of participating in the LCFS in the short term. It is important to note, however, that the economic benefits of this scenario are contingent upon finding a theoretical physical pathway to the California based end user. Therefore, the City must first conduct an investigation to confirm whether there is a theoretical pathway to the California based end user via the currently proposed interconnection and if an alternate interconnection would be required, the costs must be updated and the economic analysis re-run to determine the financial feasibility of this option.

It is also important to highlight that successfully executing the proposed scenario requires a rapid project timeline since anticipated market pressures and trends make it appear unlikely that Mesa will be able to profitably generate LCFS credits beyond 4-5 years in the future. The Set 5 Scenario analyses are summarized in Table 31 and Figure 21.

Table 31. Co-Generation and RNG Generation with Mixed HSW organic slurry Addition Scenario Estimates

Scenario	Annualized Scenario Savings [$]	GHG Reduction [MT CO_2e]	Total Project Cap Ex	Diesel Gallon Equivalents/ Day
1.3. 'Enhanced Baseline'	$21,000	221	$0	-
3.5 'No Slurry - all D3 RNG'	$497,000	1,853	$3,318,000	818
5.1 'No Slurry - all D3 RNG and LCFS'	$532,000	1,709	$3,318,000	818
3.3 'Slurry to both DIGs - all D5 RNG'	($233,00)	4,886	$14,213,800	1,722
5.2 'Slurry to both DIGs - all D5 RNG and LCFS'	$192,000	4,886	$14,213,800	1,722

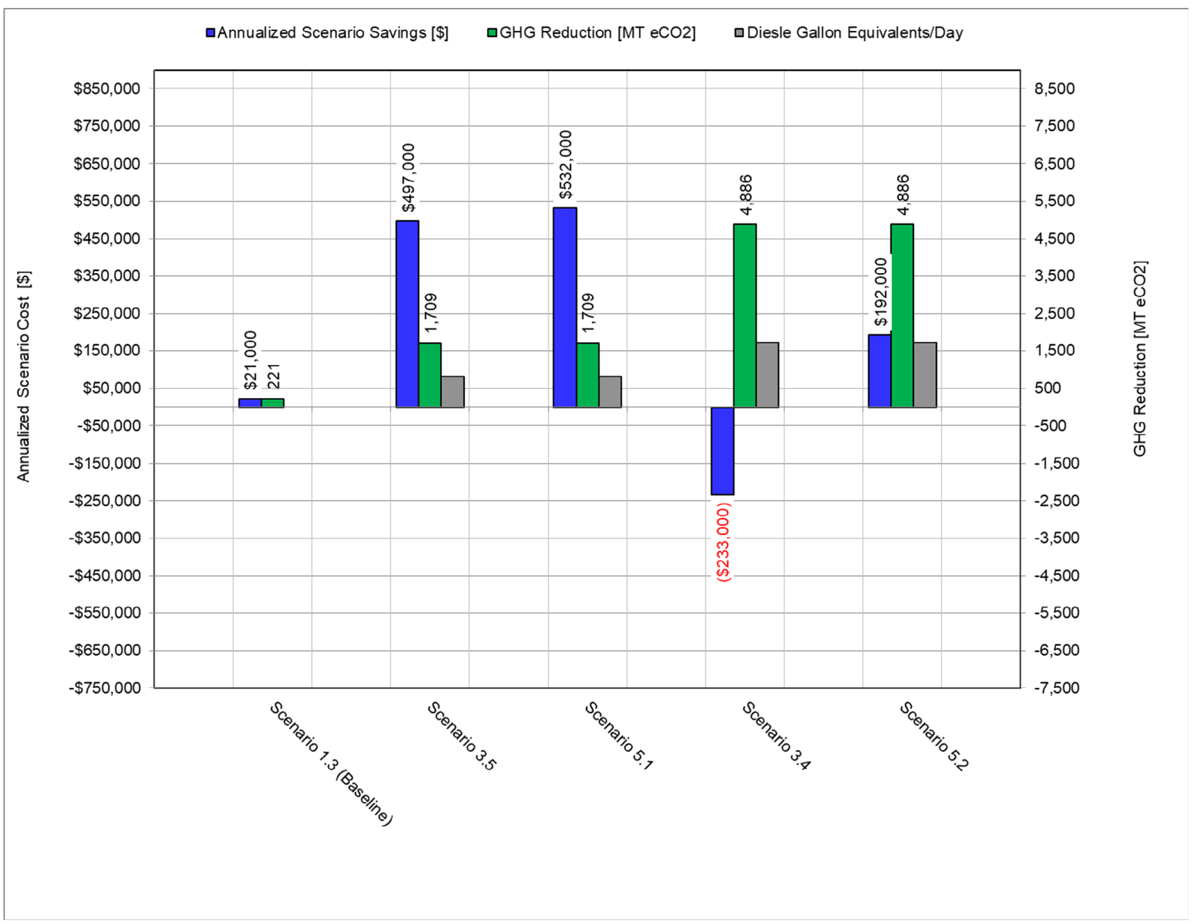


Figure 21. Participation in the Low Carbon Fuel Standard (LCFS) Program Scenario Comparison

7 RISK CONSIDERATIONS

In this section, the risks that co-digesting could potentially expose NWWRP to are evaluated. The chief risks identified include the risk of extended peak flows, upsets to the digestion process, and nutrient recycling. For reach risk identified both the likelihood of occurrence and any necessary mitigating operating procedures were assessed. To mitigate risk of digester upset a detailed breakdown of the start-up, operational and monitoring procedures for the digester has been included in this section.

7.1 Extended Peak Flows at NWWRP

Historic NWWRP flow data suggests that the plant rarely experiences extended periods of peak flows. Peak flows were identified at flows higher than 2 standard deviations above the average flow. To mitigate the risk of overloading the digesters without disrupting the operation at the Center Street Yard Organics Pre-processing Facility. The pre-processing facility will be designed with at least 2-days of storage as well. Additionally, slurry equalization at NWWRP in the PS Wet Well repurposing, there will be almost 2-days of storage availability on-site.

7.2 Digester Offline

The egg-shaped digester design at NWWRP is ideally shaped to minimize material build-up in the digester, while actively volume of the digester, and ultimately reducing the out-of-service time for maintenance. It has been reported that some egg-shaped digesters have been in service for 20 years without needing to be cleaned (Volpe et. Al. 2004).

If NWWRP needs to take a digester offline, the total amount of sludge will be sent to one digester. Under this scenario, it is expected that an average of 69,600 gpd of thickened sludge will be sent to the digester, equating in a 12.6-day SRT. Since this retention time is below the minimum recommended 15-day SRT, during periods in which one digester is offline, OSW and FOG addition must cease.

7.3 Nutrient Recycling

Under the proposed HSW loading rates, it is projected that NH_4-N concentrations in the digester will increase from approximately 550 mg/L to 1,100 mg/L, entailing a 100% increase in NH_4-N concentrations in the digester. This increase in ammonium concentration is not anticipated to be problematic for NWWRP since dewatering centrate will not be recycled to the plant headworks and instead will be sent to 91st Ave WRP for treatment.

7.4 Digester Stability

Increasing COD loading to the digester has the potential to upset digester if equalization is not provided to prevent batch loading and if the digester is not gradually acclimated to the increased

COD loads. The following recommendations for digester operations, start-up, and monitoring should be implemented to ensure digester stability with co-digestion.

Digester Monitoring

The ASU bench co-digestion study analyzed the parameters for both digesters that performed stably during co-digestion and those that soured as a result of HSW addition; as part of this analysis, several key parameters for evaluating the operational stability of a digester during co-digestion were highlighted. Those parameters are summarized as follows:

Blend Tank

- pH
- Volatile Fatty Acid Concentrations
- Alkalinity
- Feed Rate
- Volatile Solids

Digester Monitoring

- pH
- Volatile Fatty Acid Concentrations
- Alkalinity
- Volatile Solids

NWWRP will have approximately 3 days of HSW storage on-site at the recommended HSW loading rates. This allows sufficient time for testing of HSW prior to injection into the digesters. This will allow NWWRP to purge HSW that has parameters that would be problematic for digester stability. It is recommended that HSW that cannot be sent to the digester be sent to the facility headworks for treatment.

Laboratory safety

The above recommended monitoring parameters are all parameters that NWWRP already performs laboratory testing for. It is recommended that NWWRP continue to follow the same laboratory safety protocol that it currently follows since no new laboratory safety hazards are being introduced under the recommended digester monitoring.

HSW Start Up

In order to minimize the risk of souring during co-digestion start up, it is important to gradually increase HSW load rates to the digester in order to allow the digester to progressively acclimate to the increase in volatile solids loading. During this start up period, it is important to have a Digester Loading Schedule in which the digesters are carefully monitored to understand the effects of the food waste and FOG. A recommended loading schedule for a single digester is provided in Table 32 below.

Table 32. Single Digester Loading Schedule

Months	Loading	HSW Slurry Composition	Mixed Slurry Injection
1-2	25% of Goal ~1,750 lbs VS day	5,000-gal FOG (1,500 lbs VS/day) 1 tpd of food waste slurry (500 lbs VS/day)	~4,000 gpd at 6.5% TS
3-4	50% of Goal ~3,500 lbs VS day	5,000-gal FOG (1,500 lbs VS/day) 7 tpd of food waste slurry (2,250 lbs VS/day)	~5,000 gpd at 11% TS
5-6	75% of Goal ~5,250 lbs VS day	5,000-gal FOG (1,500 lbs VS/day) 11 tpd of food waste slurry (4,000 lbs VS/day) 500 gpd of dilution water	~6,000 gpd at 12% TS
7- Onward	100% of Goal ~7,000 lbs VS day	5,000-gal FOG (1,500 lbs VS/day) 16.5 tpd of food waste slurry (5,750 lbs VS/day) 1,700 gpd of dilution water	~7,700 gpd at 12% TS

8 SUMMARY AND RECOMMENDATIONS

The following section summarizes the report findings and recommendations for maintaining digester stability from co-digestion start up and onwards. Recommendations made in this section include imported waste limits, necessary digestion parameter monitoring protocol and instrumentation, co-digestion ramp up schedule, and all related biogas end use equipment sizing.

8.1 Digestion Capacity and Mixed HSW organic Slurry Loading

- Based on the limiting digestion capacity factor of 35% imported organic loading by mass fraction, the recommended amounts of each organic waste stream to be imported to NWWRP were set as follows:
  - Feeding 1 digester: 22 tpd of OSW slurry and 5,000 gallons/day both on a 5 days/week (weekday) basis.
  - Feeding both digesters: 44 tpd of OSW slurry and 10,000 gallons/day both on a 5 days/week (weekday) basis.

  OSW and FOG mixes were set to produce the optimal slurry concentrations in the range of 15% TS without the need for significant dilution water. If greater amounts of OSW and significantly less or no FOG were to be considered, then dilution water considerations must be incorporated into the Center Street Yard Pre-Processing Facility.
- At the above recommended organic waste loading rates, digester SRT is above 20 days and the OLR is approximately 0.175 lb VS/cf/day.
- The decision on whether one, two or zero digesters should be loaded with organic waste is dependent on biogas utilization as RNG and the regulatory outlook involving the accounting for D3/D5 RIN credits resulting from sludge, OSW, and FOG co-digestion.

8.2 Biogas Utilization

- Based on the comparison of model scenarios in which all biogas is sent to RNG versus scenarios where CHP is receiving biogas, it is both economically and operationally favorable to send all available biogas to RNG, even when all biogas is considered for D5 RINs. The CHP engine could still be kept in service and utilized for electric peak shaving with natural gas as the primary fuel.

- The highlighted scenario comparison in Table 33 and Figure 22 below shows the most favorable scenarios together for further examination and evaluation.

Table 33 Highlighted Scenario Comparison

Scenario	Annualized Scenario Savings [$]	GHG Reduction [MT CO_2e]	Total Project Cap Ex	Diesel Gallon Equivalents/ Day
1.3. 'Enhanced Baseline'	$21,000	221	$0	-
2.4 'HSW to both DIGs – CHP at 100%	($349,000)	562	$10,895,800	-
2.5 'HSW to both DIGs – Expanded CHP at 100%'	($336,500)	1,303	$12,220,800	-
3.3 'HSW to both DIGs – All D5 RNG'	($233,00)	4,886	$14,213,800	1,722
3.1b 'HSW to 1 DIG – D3/D5 RNG + PSA Upgrading Skid' '	($245,000)	3,333	$14,213,800	1,291
4.3 'HSW to both DIGs – CHP at 100% + RNG'	($236,000)	4,789	$14,213,800	1,665
4.5 'No HSW – all D3 RNG + NG Peak CHP'	$512,000	1,622	$3,318,000	818

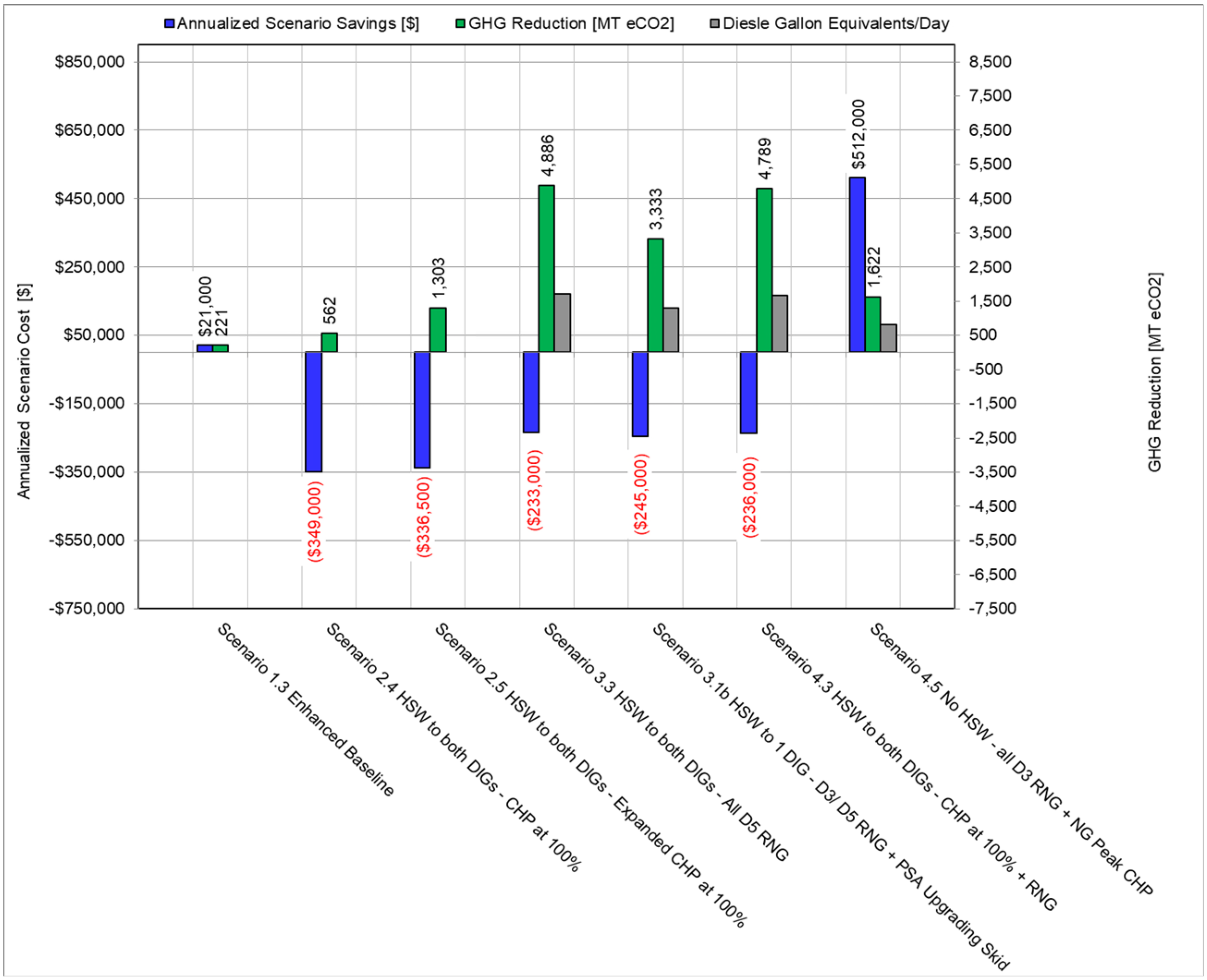


Figure 22. Highlighted Scenario Comparison

- Based on current EPA accounting for D3 and D5 RINs, the most economically favorable alternative for Mesa would be to not accept mixed organic slurry at NWWRP and retain D3 RIN status for all biogas generated from plant digesters. This would also avoid capital cost involved with constructing and operating an organic waste extraction system at the Center Street Yard Facility. However, this option does not align with the City's sustainability and project goals. See Scenario 4.5 above in Figure 22.
- Based on current EPA accounting for D3 and D5 RINs, the second most desirable alternative would be to send mixed HSW organic slurry to both digesters to maximize biogas production and keep digester feeding operations relatively simplified. This configuration better aligns with the project's sustainability and overall goals compared to not digesting imported organic waste. There did not appear to be an economic benefit to accepting less HSW to only one digester to retain partial D3 RIN classification on biogas from 1 digester.
- There are current legislative and lobbying efforts underway to amend the RFS to allow mass fraction accounting of D3 and D5 RINs based on organic loading fractions to the digesters. If

this amendment occurs, the value of accepting mixed HSW organic slurry at NWWRP increases significantly, with annual savings over baseline in excess of $600 thousand if both digesters receive mixed HSW organic slurry. In this scenario maximizing slurry to the digesters becomes the most economically favorable option.

- Based on the above conclusions, a phased approach is recommended. An RNG upgrading system should be installed as quickly as feasible in order to maximize the more lucrative D3 RIN revenue potential prior to commencement of co-digestion. Once the HSW organic slurry receiving and injecting system have been installed in the subsequent phase, NWWRP can convert to a co-digestion and D5 RIN generation configuration.
- The RNG upgrading system should be sized for the maximum mixed HSW organic slurry loading scenario, which was approximately 274 scfm. This gas flow equates to approximately 1,800 DGE/day of RNG, which matches closely with the current vehicle fleet usage rate. The system included in the conceptual design has a design capacity of 400 scfm which provides sufficient capacity to both capture peak generation rates and allow for future expansion to the co-digestion/RNG configuration if possible.

CITATIONS

1. Parkin, Gene; Owen, William. *Journal of Environmental Engineering/Volume 112 Issue 5,* 1986. Fundamentals of Anaerobic Digestion of Wastewater Sludges.
2. Rittmann, Bruce; McCarty, Perry. *Environmental Biotechnology: Principles and Applications*, 2001.
3. Lossie, U.; Pütz, P. Targeted Control of Biogas Plants with the Help of FOS/TAC; Laboratory Analysis, Titration FOS/TAC; Hach-Lange Maroc Sarlau: Casablanca, Morocco, 2001.
4. Jeffrey Peirce; Ruth F. Weiner; P. Aarne Vesilind. *Environmental Pollution and Control (Fourth Edition)*, 1998. “Chapter 9 - Sludge Treatment, Utilization, and Disposal.”

APPENDIX A

Air Quality Permit Analysis

AIR QUALITY PERMIT

The Air Quality Permit to operate and//or construct at Northwest Water Reclamation Plant was issued by Maricopa County Air Quality Department (Permit # 990546).

The specific conditions of the site outline the maximum allowable emission in pounds per year. NWWRP is not permitted to exceed any of the limits as provided in Table 1. The calculation of the 12-month rolling total emission is calculated by summing the monthly emissions over the most recent 12 calendar months. The 'historic maximum' represents the highest sum of a 12-month period which ended sometime in 2018; therefore, representing the worst-case conditions for each pollutant. It should be noted that NWWRP exceeded the 12-month rolling permit limit for SOx for the first 6-months of 2018.

Table 1. Historic Maximum vs. Permitted Facility-Wide Allowable Emissions

Pollutant	Historic Maximum 12-Month Rolling Total Emission	Permit 12-Month Rolling Total Emission Limit	Unit
Carbon Monoxide (CO)	13,378	39,206	lbs
Nitrogen Oxide (NOx)	14,371	69,097	lbs
Sulfur Oxides (SOx)	2,334	2,248	lbs
Particulate Matter <10 Micron Diameter (PM10)	2,035	2,986	lbs
Particulate Matter <2.5 Micron Diameter (PM2.5)	2,035	2,986	lbs
Particulate Matter (TSP)	2,035	2,986	lbs
Volatile Organic Compounds (VOC)	5,444	29,948	lbs

Arcadis evaluated the potential increase in emissions due to the changes recommended above. The major concerns regarding the permitted limits are the scenario 'Expanded CHP Generation with Additional Engine'. The potential increase is shown below; However, a majority of the additional emissions can be mitigated by expanding post-combustion engine exhaust equipment to include an oxidation catalyst.

Table 2. Estimated vs. Permitted Facility-Wide Allowable Emissions

Pollutant	Estimated Emissions with Expanded Cogeneration	Permit 12-Month Rolling Total Emission Limit	Unit	Meets Limit?
Carbon Monoxide (CO)	52,693	39,206	lbs	NO
Nitrogen Oxide (NOx)	36,510	69,097	lbs	YES
Sulfur Oxides (SOx)	2,334	2,248	lbs	NO
Particulate Matter <10 Micron Diameter (PM10)	2,259	2,986	lbs	YES
Particulate Matter <2.5 Micron Diameter (PM2.5)	2,259	2,986	lbs	YES
Particulate Matter (TSP)	2,259	2,986	lbs	YES
Volatile Organic Compounds (VOC)	7,967	29,948	lbs	YES

APPENDIX B

Gas Quality Tariff Specification

TRANSMISSION PIPELINE GAS QUALITY TARIFF SPECIFICATION

Components	Renewable Natural Gas
Hydrogen Sulfide H_2S	0.25
H_2O (Water Vapor)	7
CO_2 (Carbon Dioxide)	3%
N_2 (Nitrogen)	-
O_2 (Oxygen)	0.2%
Diluents	4%
Heating Value Gross	No Specification
Hydrocarbon Dew Point	20°F @ 600 psig
Hydrocarbon GPM	No Specification
Hydrocarbon Liquids	shall be free at point of Delivery
Flowing Temperatures	50°F - 120°F
Mercaptan (RSH)	0.30
Organic Sulfur (OS)	0.50
Total Sulfur (TS)	0.75
Dust, Gums, Solid Matter	Commercially Free
Deleterious Substances	shall not contain in concentrations that are hazardous to health, pipeline or merchantability
Liquids (Water & Hydrocarbons)	Free of at Delivery temperature and pressure

APPENDIX C

CENTRYSIS Pondus Thermochemical Hydrolysis Process Quote

NUMBER: 09451 DATE: 01/28/19

TO: Northwest Mesa, AZ WWTP
960 N. Riverview
Mesa, AZ 85211-1466
Attn: Roy Van Leeuwen
Ph: (480) 644-5873

REF.: PONDUS TCHP Process

Budget Proposal
Northwest Mesa, AZ WWTP
PONDUS Thermochemical Hydrolysis Process

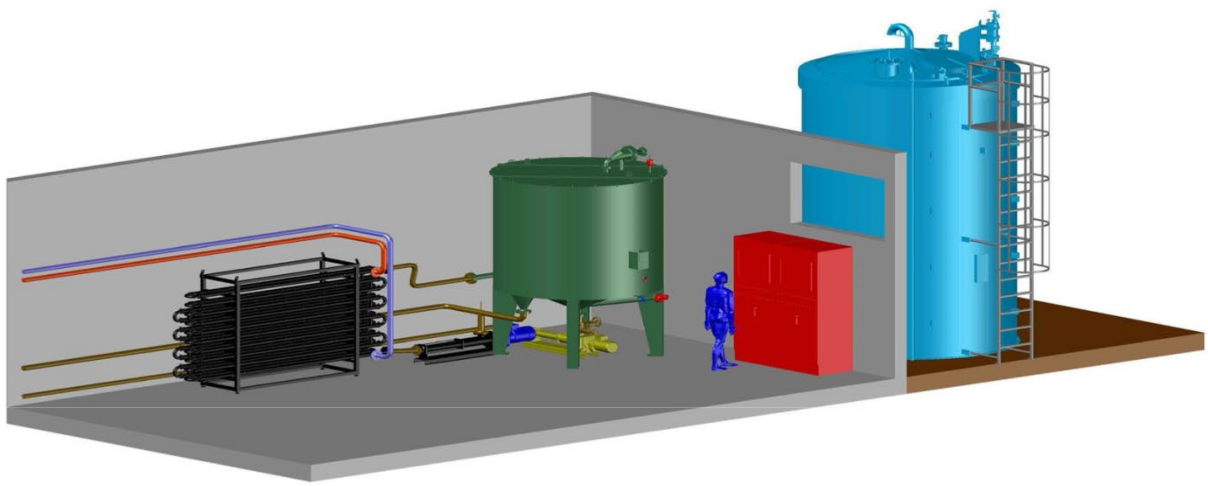
Centrisys Contacts
Jerod Swanson
Regional Sales Manager
9586 58th place
Kenosha, WI 53144
Ph: (262) 654 6006
Direct: (612) 401 2006
Email: Jerod.swanson@centrisys.us

Sanjeev Verma
Regional Sales Manager
Direct: (262) 612 9318
Email: Sanjeev.verma@centrisys.us

Centrisys Representative
John Deogracias
Goble Sampson
1745 So. Alma School Rd, Suite 275
Mesa, AZ 85215
Ph: (480) 969-3667
Email: jdeogracias@goblesampson.com

CNP is pleased to offer a budgetary proposal for the following system:

PONDUS THERMOCHEMICAL HYDROLYSIS PROCESS – WAS-ONLY, CLASS B PROCESS



System Description:

Thickened Waste Activated Sludge (TWAS) is mixed with a small dose of caustic soda before the Pondus reactor recirculation line. The chemically treated TWAS is mixed with recirculated hydrolyzed sludge and heated to around 150F, using waste heat from the cogeneration process or other heat source. The combination of heat and caustic soda destroy the cell membrane of the WAS.

During the hydrolysis process, organic acids are released. These organic acids are now converted more quickly during the anaerobic digestion process – producing approximately 30% more biogas in the anaerobic digester. The process results in at least a 5-fold reduction of dynamic viscosity of TWAS. Therefore, more solids can be process in the digester with less energy required to heat, pump, and mix. The hydrolyzed sludge generates dryer cake and lowers the polymer consumption during dewatering (lower dewatering and disposal costs).

Benefits:

- Improved efficiency of anaerobic digestion
    1. Enhance biogas production between 20-30%
    2. Improve volatile solids reduction ratio
    3. Reduction or elimination of digester foaming
- Reduced sludge viscosity by up to 60%
    1. Less energy for heating, pumping, and mixing
    2. Increased solids in the digester
    3. Less digester retention time
- Improved digested sludge dewaterability
    1. Dryer cake – DS improvement of 3-6%
    2. Polymer usage reduction up to 10%
    3. Reduction of dewatering and disposal costs
- Optional – Class A biosolids

ITEM 1 DESIGN PARAMETERS

Our design calculations are based on the hydrolysis of thickened activated sludge:

Parameter	Unit	Value
Digested sludge flow rate to PONDUS TCHP	gallon/min	16.5
Total Solids % of feed sludge	%	6
50% w/w NaOH solution consumption (24 hr/d operation)	gallon/day	35.7
Estimated annual NaOH dosing cost (@$1.8/gal)	$/year	23,455
O&M Labor requirements	hours/day	<1

ITEM 2 SCOPE OF SUPPLY

ITEM	QUANTITY	DESCRIPTION
1	1	PONDUS TCHP reactor
2	2 (1 duty, 1 standby)	Feed pump
3	2 (1 duty, 1 standby)	Recirculation pump
4	2 (1 duty, 1 standby)	Reactor discharge pump
5	1	Heat water heat exchanger
6	1	NaOH solution dosing system
7	1	NaOH solution storage tank
8	1	Instrumentation and controls
9	1	Start-up and commissioning services

ITEM 3 SYSTEM PERFORMANCE

Reduce TWAS viscosity	up to 80%
Enhance biogas production	up to 30%
Improve volatile solids reduction ratio	up to 6%

ITEM 4 SERVICES

4.A Drawings and Installation, Operation and Maintenance (IO&M) Manuals:

1. Submittal Drawings: One (1) electronic copy; prints by request
2. Final Drawings: Two (2) prints & One (1) electronic copy included
3. O&M Manuals: Two (2) prints & One (1) electronic copy included

4.B Start-Up Assistance:

CNP will furnish one factory representative to assist in installation inspection, start-up supervision, and operator training. Dates of service to be scheduled upon Buyer's written request.

BUDGET PRICE:

All of the above for .... $**1,266,400** USD

F.O.B. Kenosha-WI, freight included, taxes excluded.

PAYMENT TERMS:

30% with order; 60% upon shipment; 10% after startup not to exceed 90 days after shipment.

ITEM 5 TIMETABLE

Submittal phase: 6-8 weeks after the order receipt

Approval phase: 4 weeks for the customer to approve the drawings

Shipment phase: 32-34 weeks following receipt of the Approval drawings

Additional on-sit installation time (by others): 3 weeks after delivery

Dates are subject to confirmation upon receipt of written Purchase Order.

ITEM 6 WARRANTY

One (1) year from the equipment start up or eighteen (18) months from delivery.

BUYER/OWNER RESPONSIBILITY:

- Any site preparation work including surveying and soil sampling
- Civil works such as the foundation plate for the system or the building
- Pipes and piping (except from the outside flange of the reactor the aeration ring inside the reactor)
- Sludge holding or storage tanks for sludge equalization
- We have assumed that all components except the storage tank will be installed underneath the reactor in the associated machine room. The storage tank with the filling station will be installed at a distance of max. 15 m (45 ft) from the building.
- Supply lines (water and electricity) as well as building services (lighting, water supply / sink) in the office building
- Concrete work and core drill holes
- Permits
- Building and building plans (Centrisys provides only the layout drawings without any responsibility of updating any plans or building)
- Building modifications
- Structural and Civil engineering labor
- All utilities that are required for operation
- Unloading, uncrating, installation and installation supervision. Installation will, at minimum, require a forklift and possibly a crane/hoist.
- Readiness of the Equipment before requesting start-up service. Non-readiness may incur additional charges.
- Compatibility of Equipment materials of construction with process environment.
- Any other auxiliary equipment or service not detailed above.

Issued by

Zach Mazur
Applications Engineer

Date: 01/28/19

APPENDIX D

AIR LIQUIDE MICROBIOGAS™ System for Biogas Quote

CONFIDENTIAL

January 21, 2019

Eric Auerbach/Andrew Deur
Arcadis

Subject: Air Liquide MicroBiogas™ System for Biogas – **100, 450, 700, 900 SCFM**

Dear Eric/Andrew:

Air Liquide is a leader in the supply of membrane based systems and has a portfolio of membranes unmatched in the industry. For biogas upgrading, we have provided over 60 units to date. Units range widely in size (largest is over 10,000 SCFM) and we have recognized the market need for a low cost, small system. We have scaled down our system for smaller flows while taking advantage of the range of membranes that Air Liquide manufactures.

For the small system we incorporate the membranes on the compressor skid (100 SCFM) and for moderately sized systems (450, 700, 900 SCFM we offer a simplified membrane skid and a compressor skid that sits close to the membrane skid. Interconnecting piping by others is required. The membranes applied are unique in the ability to highly selectively reject H_2S and they also reject water, CO_2 and some O_2.

For your feed, we designed for feed rates of 100, 450, 700 and 900 SCFM. The process flow assumes compression and then routing of the 150 ppm H_2S gas through a H_2S scavenger. The gas is then processed by the membrane after chilling. Some of our customers assume that the reject gas can then be vented and thus a thermal oxidizer is avoided.

Alternately, we can remove the H_2S with the membrane system (thus no H_2S scavenger). If that were the case the reject stream would be routed to a thermal oxidizer (not included).

Design Material Balance:

	Design Basis Feed (wet)	Product	Tail Gas to Thermal Oxidizer
Case #1, Flow SCFM	100	55	42
Case #2, Flow SCFM	450	247	189
Case #3, Flow SCFM	700	384	293
Case #4, Flow SCFM	900	493	377
Pressure, psig	0	140	1
Temperature, F	100	~100	~100
Composition, Mol%			
C1	55.00	97.45	3.94
CO2	40.40	1.00	95.15
O2	0.30	0.18	0.48
N2	0.80	1.37	0.11
H2S	150 ppm – removed with scavenger	4 ppm	~ 10 ppm
H2O	3.50	<7lb./MMSCF	0.32
HHV BTU/FT3		984	40

Note:

1. The design methane recovery rate is 97%.
2. Tail gas is lean in heating value and assumed routed to a thermal oxidizer (supplemental pipeline natural gas would be required).
3. Condensed water from compression is about 25, 105, 165 or 210 Gallons per day. The condensed water removed is the reason the product and tail gas flow rates do not add to the feed flow rate.

EQUIPMENT:

One feed compressor with inlet separators, gas and oil coolers, required skid instrumentation, compression with electric motor and direct drive plus membrane skid/modules are included. A compressor discharge air fan cooler is provided.

A separate membrane skid is provided except for the 100 SCFM where the membranes are mounted on the compressor skid.

An Allen-Bradley PLC with local panel and separate HMI is included. The PLC is mounted on the compressor skid.

The area classification is NEC Class I, Div 2 which is typical for upgrading equipment.

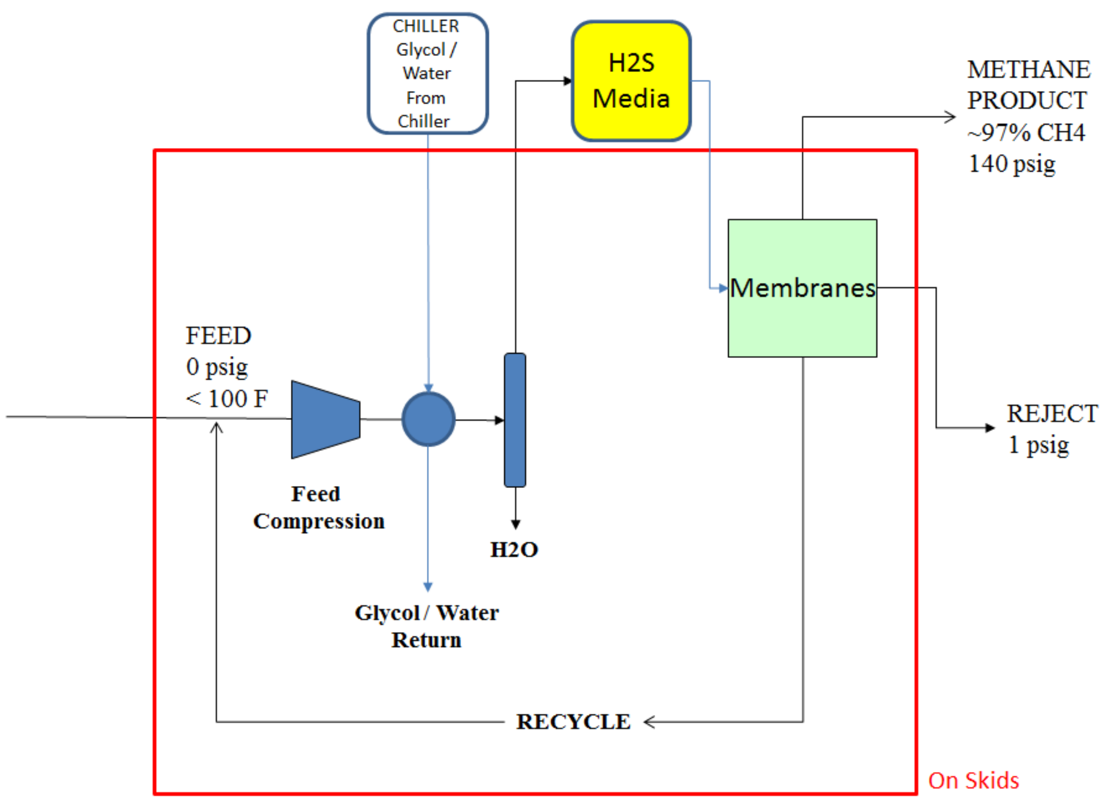
INSTALLATION:

For cases 2, 3, and 4 the installation requires that the compressor and membrane skid be tied together. We would design to minimize the field piping. After compression the product is routed through a polishing vessel for H2S removal to 4 ppm.

Compression requires motor starters (not included) and is the main electrical requirement.

PROCESS FLOW SHEET:

1. Feed plus recycle compression to 200 psig
2. H2S scavenger
3. Membrane treatment to remove water, residual H2S, O2 and CO2.



PRELIMINARY

FEATURES:

- Easy, largely unattended operation with high on-stream factor
- Automatic turndown/turn-up (to < 20%)
- CO_2 purity is monitored with a CO_2 IR analyzer supplied
- Flexible to changes in the feed composition
- Dry process with no byproducts other than water from feed compression
- Design for easy installation
- Push-button start-up and shutdown
- Capacity regulated by maintaining a fixed pressure in the digester to avoid upsets to the digester operation

SUMMARY & COST:

Case #	1	2	3	4
Feed, SCFM	100	450	700	900
Budgetary Equipment Cost: MicroBiogas system including feed compression, membrane skid, H_2S scavenger bed with first load of media. $ EXW USA Shop	**$ 645,000**	**$ 1,380,000**	**$ 1,600,000**	**$ 1,700,000**
Annual media replacement cost, $	**$ 6,000 (first load included)**	**$ 27,000 (first load included)**	**$ 45,000 (first load included)**	**$ 54,000 (first load included)**
Start-up per diem	**$ 1800 per day plus expenses. Assume 7 days for two individuals.**	**$ 1800 per day plus expenses. Assume 7 days for two individuals.**	**$ 1800 per day plus expenses. Assume 7 days for two individuals.**	**$ 1800 per day plus expenses. Assume 7 days for two individuals.**
Adder for thermal oxidizer / Flare	By others if used	By others if used	By others if used	By others if used
Shipping cost (USA)	TBD	TBD	TBD	TBD
Estimated Annual Maintenance Cost	Assume 2% of capital per year. This is conservative. For oil and filter changes.	Assume 2% of capital per year. This is conservative. For oil and filter changes.	Assume 2% of capital per year. This is conservative. For oil and filter changes.	Assume 2% of capital per year. This is conservative. For oil and filter changes.

Note:
• For the design we have assumed that typical national codes are applied (ASME Section III, Div. 1, ANSI B31.3, NEC Class I Div 2).
• Standard mechanical warranty is 12 months from start-up, 15-months from delivery. Product purity of $CO_2 < 1\%$ is guaranteed.
• Standard payment terms are approx. 1/3rd to start, 1/3rd midway through the project and 1/3rd on delivery
• Minimum ambient temperature: In building, maximum ambient temperature 100 °F
• Elevation assumed as 1300 ft.

SCOPE:

Air Liquide	Customer
Feed compression with associated discharge air-fan cooler	Feed gas supply to inlet of the compressor including inlet pressure signal. Supply and installation of feed, product and tail gas piping to/from skid
Membrane skid with membrane modules	Equipment shipping to field and installation including foundation, equipment setting and supply/plumbing of interconnecting piping
Scavenger vessel with first charge of media	Motor starters and electric wiring to/from the skid
Compressor discharge chiller	Labor, material and supplies during installation, start-up and performance testing
Allen-Bradley PLC for control of the equipment with desktop PC HMI interface	Disposal of condensate (from compression/cooling)
Start-up is per diem	Utilities listed below
	Product use and product flow, purity measurement
	Tail gas disposal/flare

MAIN ITEMS THAT ARE NOT INCLUDED:

- Flow meters and analyzers
- Thermal oxidizer or flare
- Installation / buildings
- Field service and hazop attendance is per diem

UTILITIES:

Case #1	Motor, HP	Power, kW	Starters
Feed Compressor	75	43	VFD by others
Air Fan Motor	5	3	VFD by others
Oil Heater		1	Contactor
Chiller		5	Contactor
TOTAL		**52 kW**	

Case #2	**Motor, HP**	**Power, kW**	**Starters**
Feed Compressor	300	190	VFD by others
Air Fan Motor	15	7	VFD by others
Oil Heater		2	Contactor
Chiller		11	Contactor
TOTAL		**210 kW**	

Case #3	**Motor, HP**	**Power, kW**	**Starters**
Feed Compressor	600	314	VFD by others
Air Fan Motor	15	10	VFD by others
Oil Heater		3	Contactor
Chiller		17	Contactor
TOTAL		**344 kW**	

Case #4	**Motor, HP**	**Power, kW**	**Starters**
Feed Compressor	700	378	VFD by others
Air Fan Motor	25	15	VFD by others
Oil Heater		3	Contactor
Chiller		19	Contactor
TOTAL		**415 kW**	

Instrument Air: 5 SCFM @ 60-100 psig, -40F dew point.

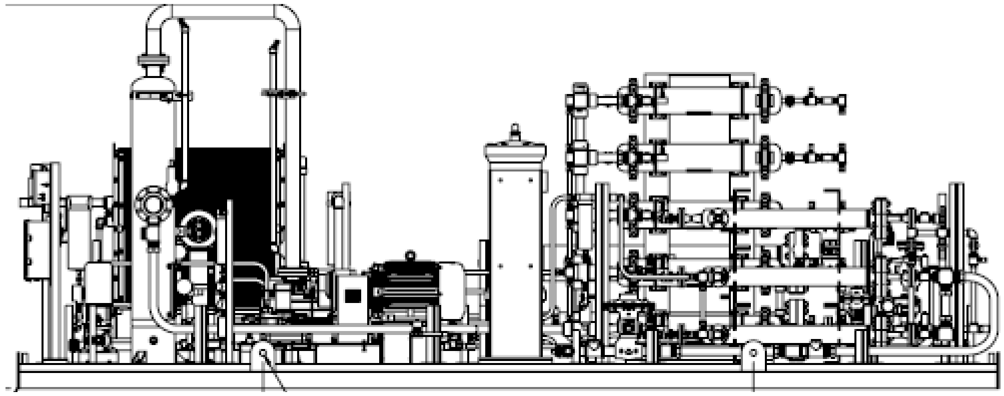
Dry Gas: A six-pack of N2 cylinders should be maintained.

An alternate to the above instrument air and N2 is to add a 1000-gallon buffer tanks for dry gas storage.

DELIVERY TIME:

We expect about 8 months.

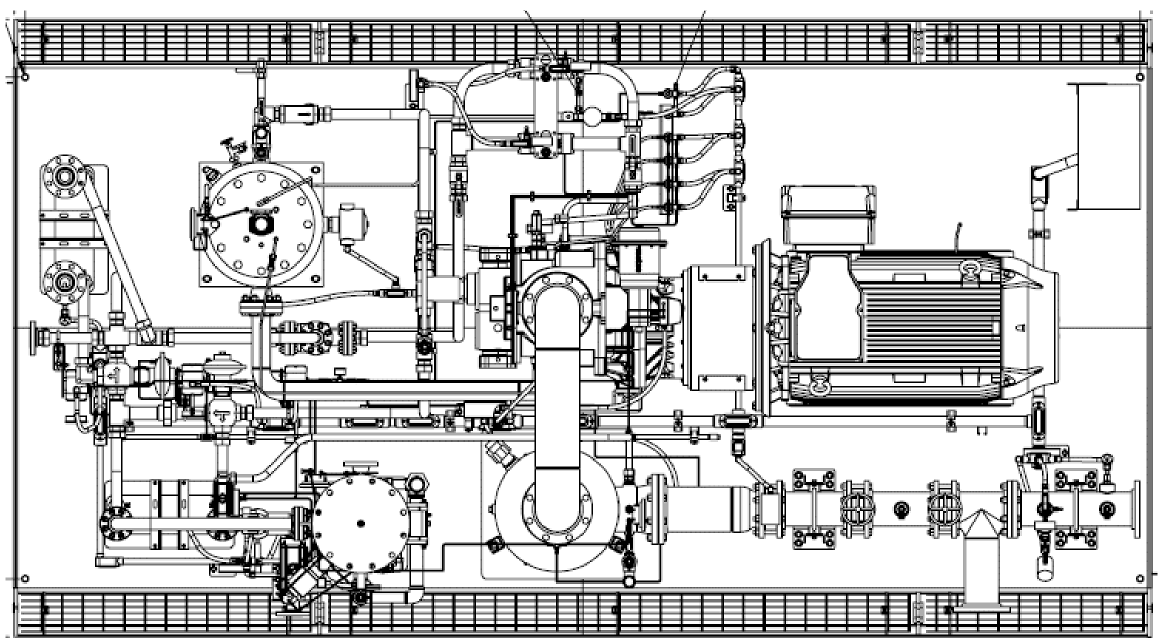
Below Footprint applies to Case #1:



About 20-ft long and 9-ft wide.

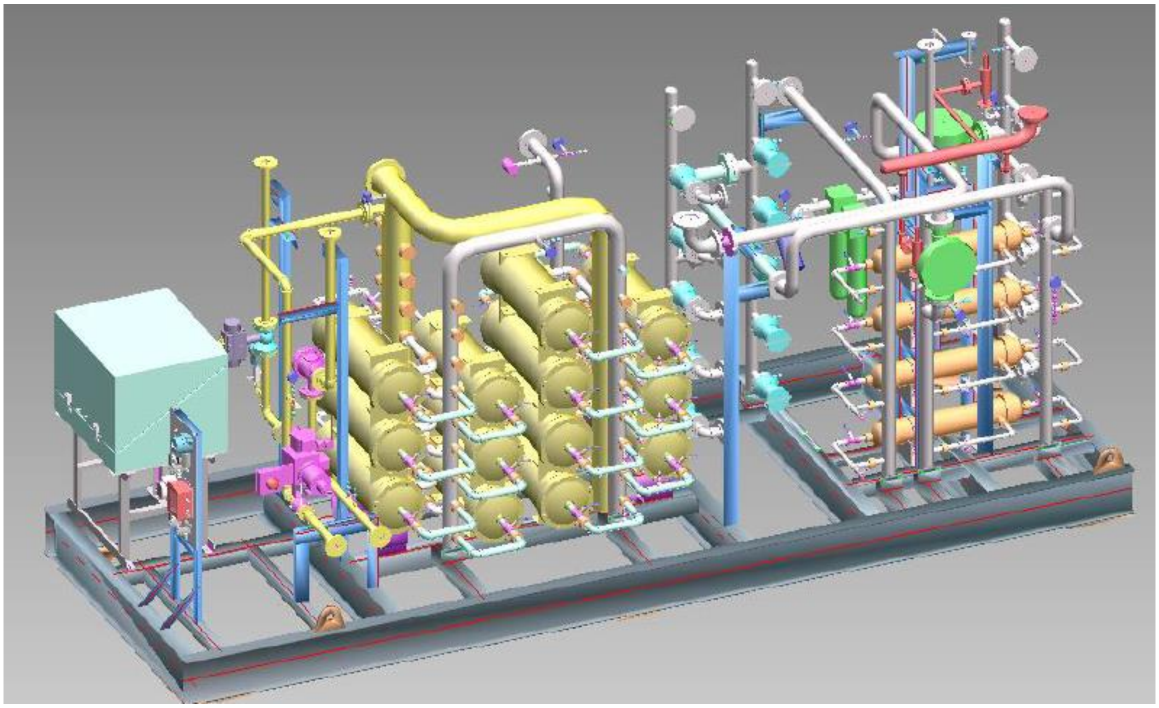
Below Footprint applies to Case #2, 3, 4:

FOOTPRINT – SIMILAR FEED COMPRESSOR:



Air Fan cooler of 12-ft by 15-ft not shown.

FOOTPRINT – SIMILAR MEMBRANE SKID:



We hope the above is helpful for your evaluation.

Joseph P. Bushinsky
Air Liquide Advanced Business & Technologies
Cell: 484-666-9088
E-mail: joseph.bushinsky@airliquide.com

THIS BUDGETARY PROPOSAL IS FOR DISCUSSION PURPOSES ONLY AND DOES NOT CONSTITUTE A BINDING CONTRACT FOR AIR LIQUIDE TO PROVIDE ANY PRODUCTS OR SERVICES. ADDITIONAL DISCUSSIONS BETWEEN THE PARTIES ARE NECESSARY TO FINALIZE DESIGN SPECIFICATIONS AND SCOPE OF SERVICES TO BE PROVIDED BY AIR LIQUIDE. THE FINALIZED SCOPE, DESIGN, TERMS AND CONDITIONS, WARRANTY, PRICES, ETC. WILL BE PRESENTED IN A FINAL, BINDING PROPOSAL AFTER RECEIVING AIR LIQUIDE MANAGEMENT APPROVAL.

EXPERIENCE:

As noted Air Liquide has provided many membrane based biogas units as per the list below.

Biogas upgrading unit- Air Liquide references list					Last update: 20-Jul-15	
N°	Country	City	Year	Project	Raw biogas Nm3/hr	Gas destination
			Europe and Asia			
1	France	Château Renard	2015	Gartinais Biogaz (ALAB)	300	Grid injection
2	Denmark	Roslev	2015	Purac-Puregas	900	Grid injection
3	China	Hangzhou	2015	HEEE	1500	CNG
4	England	Methwold	2015	Future Biogas	900	Grid injection
5	England	Metheringham	2015	Future Biogas	700	Grid injection
6	England	Cumbernauld	2014	Air Liquide UK	900	Grid injection
7	England	Teesside	2014	Air Liquide UK	900	Grid injection
8	Hungary	Kaposvar	2014	Agrana	1,500	Grid injection
9	Germany	Peine	2014	Peine	1,400	Grid injection
10	France	Villeneuve sur lot	2014	Fonroche (ALAB)	800	Grid injection
11	France	Sarreguemines	2014	Methavos (ALAB)	200	Grid injection
12	Wales	Wrexham	2014	Welsh Water Five Fords	900	Grid injection
13	France	Chagny sur Saône	2013	TIRU	1000	Grid injection
14	England	Springlindton	2013	Future Biogas	900	Grid injection
15	England	Hibaldstow	2013	Future Biogas	900	Grid injection
16	England	Holkham	2013	Future Biogas	900	Grid injection
17	France	Saint Pourcin sur Sioule	2013	Sioule Biogaz	70	Grid injection
18	England	Doncaster	2012	Future Biogas	900	Grid injection
19	France	Chaumes en Brie	2012	Bioénergie de la Brie	250	Grid injection
20	France	Forbach	2011	SYDEME	100	Grid injection
21	Sweden	Lidköping	2010	Göteborg Energi	800	Biomethane liquefaction Fuel for vehicle
22	Austria	Vienne	2011	Vienna University	6	Pilot Plant *Axiom with AL membranes*
23	Austria	Wiener Neustadt	2010	Wiener Neustadt	260	Grid injection *Axiom with AL membranes*
24	Germany	Baden-Württemberg	2010	Kißlegg	350	Grid injection *Axiom with AL membranes*
25	Austria	Margarethen am Moos	2007	Margarethen am Moos	70	Fuel for vehicle *Axiom with AL membranes*
26	Austria	Bruck an der Leitha	2007	Bruck an der Leitha	200	Grid injection *Axiom with AL membranes*
			North & South America			
27	Oklahoma	Oklahoma City	2015	Oklahoma City LF	4,200	Grid Injection
28	Chile	Santiago	2015	La Farfana WWTP	3,700	Pipeline system
29	Ohio	Columbus	2014	SWACO	10,000	Grid Injection
30	New York	Seneca Falls	2014	Seneca Meadows	5,000	Grid Injection
31	Illinois	East St Louis	2014	Milam LF	5,800	Grid Injection
32	Brazil	Rio di Janeiro	2013	Novo Gramacho	16,000	Local Industry
33	California	San Diego	2012	Pt Loma	2,400	Grid Injection
34	California	Fresno	2012	Fresno	2400	Local Use
35	Tennessee	Athens	2011	Meadow Branch	4,730	Pipeline system
36	Louisiana	New Orleans	2009	River Birch	10,600	Pipeline system
37	Pennsylvania	Pittsburgh	2009	Seneca	4,730	Grid Injection
38	Washington	Seatle	2009	Cedar Hills	18,900	Grid Injection
39	Georgia	Atlanta	2009	Live Oak	8,268	Grid Injection
40	Tennessee	Church Hill	2008	Carter Valley	2,350	Grid Injection
41	Georgia	Winder	2008	Winder	7,079	Grid Injection
42	Oklahoma	Oklahoma city	2008	Oklahoma	2,350	Pipeline system
43	Pennsylvania	Caimbrock	2007	Shade	4,728	Pipeline system
44	Pennsylvania	Imperial	2007	Imperial	7,079	Pipeline system
45	Pennsylvania	Davidsville	2007	Southern	2,350	Grid Injection
46	Pennsylvania	Kersey	2007	Greentree	14,158	Grid Injection
47	Tennessee	Johnson city	2006	Iris Glen	2,350	Grid Injection
48	Pennsylvania	Raeger mtn	2006	Laurel Highlands	4,728	Grid Injection

APPENDIX E

GUILD Biogas Upgrading Equipment Quote

Guild Associates, Inc.
5750 Shier-Rings Road
Dublin, OH 43016
Phone: (614) 798-8215
Fax: (614) 798-1972

April 23, 2019

Shayla Allen
Arcadis US, Inc.

Quotation 19-B035
Subject: Biogas Upgrading Equipment, Mesa AZ WWTP

1. Introduction

Guild is pleased to present its Molecular Gate™ PSA technology for the purification of digester gas. Our technology uses single step removal of impurities to meet the pipeline specifications that you have outlined. We are offering a fully integrated package that includes feed compression, Molecular Gate PSA system and vacuum compression. This is a combination of new equipment (feed compression) and never-installed Molecular Gate PSA system with vacuum compression refurbished to like-new condition.

Rough Order of Magnitude (ROM) Estimate

This ROM is not an offer to perform a service, it is submitted as an estimate for your budgetary and planning purposes only, and is valid for 90 days. Design and equipment information contained in this document are preliminary and subject to change as systems at this scale are custom engineered to suite your application.

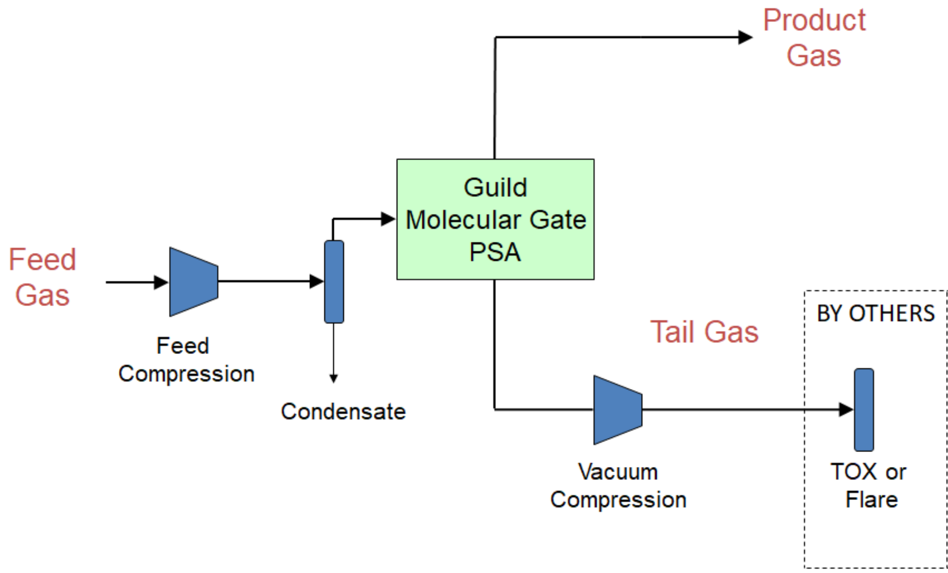
The formal proposal includes a statement of work, pricing, and Guild's terms and conditions.

Compliance to the following factors can and will affect the actual system price and delivery:

- Design specifications including feed composition and flow and product specifications
- Federal, State, and Local Codes/Regulations
- Applicable process, fabrication, and electrical codes/specifications and required certifications
- Documentation requirements

2. Process Flow Sheet

This flow sheet shows a simplified overview of the process.



3. Process Description

1. Feed compression to 100 PSIG
    a. Gas is cooled and condensate is removed
2. Molecular Gate™ PSA treatment to remove contaminants
    a. A Vacuum compressor is used to regenerate the media by removing the contaminants
3. Tail gas to TOX/Flare is required. Guild can provide an equipment and integration solution for this process requirement if requested.

4. Mass Balance Table

This table is simplified to show only the inlet and outlets of the system.

Attribute	Feed Gas (Wet Basis)	Product Gas	Tailgas
Normal Flow (SCFM)	400	223	166
Normal Flow (MMSCFD)	0.6	0.3	0.2
Pressure (PSIG)	2.0	90	2
Temperature (F)	100	120 [3]	180
Composition (Mole %)			
C1[1]	58.18%	96.03%	11.20%
N2	0.80%	1.44%	0.00%
CO2	37.00%	1.99%	86.36%
O2 [2]	0.30%	0.54%	0.00%
H2S (PPM)	150	<0.25 grains / 100SCF	361
H2O	3.70%	< 7lbs/MMSCF	2.40%
HHV (BTU/SCF)	588	970	113

Notes:

1. Typically, small 3-Bed CO_2 rejection plants provide 92% recovery. Actual recovery is based not only on plant performance, but actual gas composition and flow. Our experience is that the gas composition and flow as stated at the time of proposal development may vary from what is present when the plant is commissioned. In addition, once the plant is operational there are likely to be seasonal and year to year variances as well. Based on these factors the actual recovery percentage can only be estimated and not guaranteed.
2. Oxygen in the product gas exceeds the 0.2% limit from the pipeline company. Common good practice in digester operation should result in O_2 not exceeding 0.1% in the feed gas. Guild recommends that the operator pursue good digester practice in the sealing of tarps and barriers against atmospheric infiltration to eliminate the need for O_2 removal equipment.
3. This quotation assumes that air cooling is sufficient for cooling gas to injection temperature. Additional cost and equipment will be necessary if the ambient high temperature does not allow for air fin cooling.

5. SCOPE

Guild supplied:

1. Skid mounted gas processing equipment:
    a. One (1) Feed compressor with on-skid oil/gas cooler
    b. Refurbished Never-Installed Equipment:
        i. Feed flow meter
        ii. Molecular Gate™ PSA system including:
            1. Valve and piping skid which includes:
                a. 3 Adsorber vessels with media
                b. 1 Vacuum compressor with on-skid oil cooler
            2. Tank Skid – 7-high stacking, includes 5 buffer tanks and 2 tail gas tanks
        iii. Tail gas flow controller
2. Thermal insulation of on-skid equipment as required for the process
3. Insulation and heat trace of on-skid equipment as required for freeze protection of condensate
4. Other supplied equipment:
    a. Instrument Air System (10 SCFM, 100 psig, -20 °F dew point, to be located in MCC Building)
5. PLCs for control of Guild equipment and desktop PC HMI interface (with internet allows remote access, HMI to be located in control room)
    a. PLC: Allen Bradley CompactLogix
    b. Programing: RSLogix 5000 by Rockwell Automation
    c. HMI: Citect, now part of Schneider Electric

Customer provided:

1. Feed gas supply to inlet of Guild system
2. Installation of Guild supplied equipment including, but not limited to:
    a. Shipping
    b. Setting equipment
    c. Foundations
    d. Piping to, from and between skids and vessels
    e. Electrical
        i. Wiring to, from, and between skids
        ii. Motor starters
        iii. MCC Building
        iv. MCC interface panel (to be located in MCC building)
        v. Ethernet to, from, and between skids
    f. All labor, material and supplies associated with installation, start up and performance testing

g. Product Gas Flow Meter
3. Lighting, roadways, sidewalks, buildings, and fireproofing as required
4. Condensate disposal system
5. Thermal insulation of off-skid piping and vessels as specified by Guild
6. Insulation and heat trace of off-skid piping as required for freeze protection of condensate
7. Product purity analysis (Guild monitors CO2 Purity only) and product flow measurement as required
8. Thermal Oxidizer (TOX) and/or Flare as required for disposal of tail gas and/or start up/ off spec gas.

6. Utilities

Nitrogen: as required for maintenance purging

Power					
Description	**Motor Size (hp)**	**Voltage[1]**	**Quantity**	**Total Power (kW)[2]**	**Motor Starter[3]**
Feed Compressor	150	460	1	112	VFD
Feed Gas/Oil Cooler	2	460	1	1	VFD
Vacuum Compressor	75	460	1	56	Soft Start
Vacuum Oil Cooler	2	460	1	1	VFD
Total				**171**	**kW**

Notes:

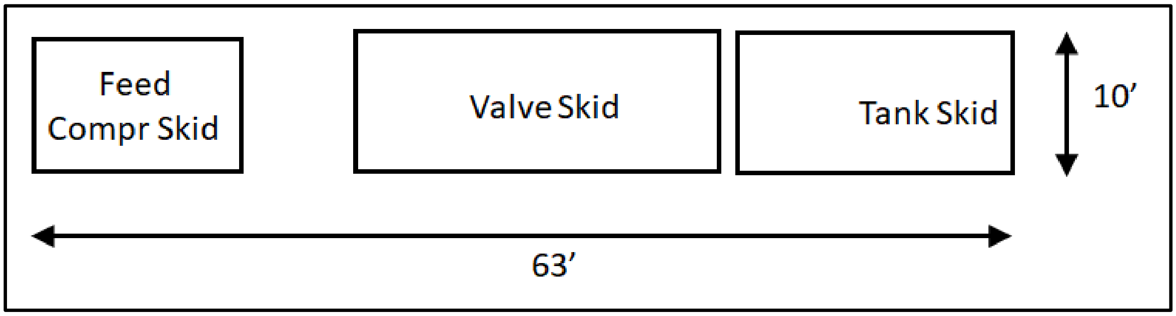
[1] Motor voltage of 460 volts is assumed.

[2] Power consumption calculated above is conservative and is based on motors running at their full nameplate load. Power savings during turndown is noticed through turndown of an individual unit or shutting equipment down if not needed. This function is included in the control system of the plant.

[3] Motor starter type is based off Guild's experience with past projects and are provided by others. We can modify our design based on customer request; however a cost adjustment may be necessary.

7. Equipment Footprint and Site Details

The figure below shows the rough equipment footprint for refurbished equipment.



The picture below shows an installed Valve Skid and Tank Skid

The table below indicates the approximate weights and sizes of the equipment

Item	Ship Weight	Site Weight	Dimensions
PSA Skid	35,000	35,000	25’ x 10’
Bottom 4 Tanks	13,000	21,000	19’ x 10’ x 19’
Top 3 Tanks	8,000	(on Tank Skid)	
Feed Compressor	15,000	15,000	14’ x 9’

8. Experience

Guild has biogas plants in operation at landfills, waste water treatment plants, lagoon digesters and other facilities where the biogas is purified to either pipeline or LNG specifications. Our portfolio of equipment includes: feed compression, pressure swing adsorption (PSA), Temperature Swing Adsorption (TSA), membrane, vacuum compression and product compression. We have standard system offerings or can custom build a package to meet individual customer needs. Guild Molecular Gate™ PSA systems use only regenerable media with our longest running plant in operation since 2004. Tours of operating commercial units in similar scale and application can be arranged upon request. Below is a map of US locations and a summary of our experience to date.

1. Biogas plant locations:
    a. USA
    b. Canada
    c. UK
    d. Brazil
    e. Philippines
2. Feed Flows: 75 to 8,000 SCFM
3. Contaminants removed:
    a. Bulk rejection of:
        i. CO_2- up to 40%
        ii. N_2- up to 17%
    b. Rejection of trace components:
        i. H_2S- up to 1%
        ii. H_2O

iii. O2
iv. VOCs[1]
v. Siloxanes[1]
vi. Heavy Hydrocarbons (C6+)
vii. Ammonia (NH3)

4. Product Compression:
    a. Pressure up to 1,400 PSIG for high pressure interstate pipeline
    b. CNG up to 4,500 PSIG with both slow fill and direct fill

[1] Upon request we can provide gas analysis from an independent 3rd party lab of an operating commercial unit in landfill service to demonstrate removal capabilities of trace organic components and siloxanes.

9. Design Basis

All gas processing equipment is designed for outdoor service in a Class 1 Div 2 area. The plant is design for single operator start up and can run unattended. Automatic turndown and purity control are included standard in our control system. Components are industrially available and are serviceable by local mechanics. Uptime of 98% has been experience for similar facilities. Estimated downtime is 1% for planned maintenance and 1% for unplanned maintenance.

Location: Mesa AZ

Elevation: 1250 ft

Ambient temperature: -20 to 110 °F

10. Design Codes and Standards

<u>Control System</u>

The Guild control system uses Allen Bradley Compact Logix PLCs. The entire Guild package operates together in a seamless manner since all of the logic is authored by Guild. Our system can also accept and transmit signals as desired in order to integrate with other vendor equipment or a Balance of Plant (BOP) SCADA system. A desktop HMI running Citect software is provided to monitor the equipment and for data logging and trending. The plant is fully automated to allow for remote operation, startup and shutdown.

Guild's standard control philosophy allows for equipment operation without operator input. The system will automatically adjust based on gas flow and product purity setpoints. In the event of a failure of an independent piece of equipment, the system will adjust other operating parameters in order to maintain maximum operating capacity with the remaining operational equipment. Equipment turndown to 25% is standard.

<u>Electrical</u>

Skid mounted electrical equipment such as motors, instrumentation and controls will be suitable for NEC Class 1 Div 2 Group D as required. Instrumentation wiring and power of 120 V and above is run in separate intermediate conduits. Instrumentation wiring is run to the instrument in conduit and uses shielded conductors to prevent erroneous instrumentation readings and thus reduces the likelihood of plant shutdowns. All wiring with in a cabinet is done in wire duct and low power instrumentation is physically separated from 120V and above. Only UL Type 4 cabinets or better are used for the housing the Guild supplied controls.

<u>Painting</u>

All individual piping, frames and vessels are painted before assembly then touched up after assembly. This prevents hardware from being coated with a layer of paint, assuring that any disassembly is less difficult.

All skids are primed, intermediate and final coat painted. All seams are caulked to prevent crevice corrosion. Standard color is window gray (RAL 7040).

<u>Piping</u>

Piping is fabricated in accordance with ASME B31.3, and ANSI B16.5. Both 304 stainless steel and carbon steel piping are used on this system.

<u>Pressure Relief Valves</u>

As required by code relief valves will be provided and are sized in accordance with API RP520. Relief valves internals that are in constant contact with the process are 304 stainless steel or better. As provided the relief valves individually route to atmosphere.

<u>Testing</u>

A factory acceptance test is performed on each skid to ensure the equipment is in good working order. Tests can we witnessed by the customer if desired. Acceptance test tasks vary from skid to skid but can include: leak test, I/O check-out, P&ID inspection, GA dimensional inspection, software checkout (such as shutdowns and operational controls) and run test (for select rotating equipment).

Vessels

All vessels are fabricated in compliance with ASME Section VIII, Division 1. An appropriate pressure and temperature rating are selected based on the service of the vessel.

Adsorber vessels are specifically engineered for PSA service and are fabricated using carbon steel SA-516 Grade 70 (or equivalent). Welds are 100% X-ray inspected and the vessel is post weld heat treated to relieve weld stress. Vessels contain a 304 stainless steel full bed support for proper flow distribution. For more information on PSA vessel design you can refer to "PSA Vessel Technology: An Overview" published by ASME.

11. Price

One Refurbished PSA, New Feed Compressor **$ 995,000**

Commissioning/Startup labor and travel will be separately billed at Guild Associates standard rates. Commissioning (Five days onsite commissioning, two people) is estimated to cost $21,500 per system. Shipping costs are separate and will be paid by the customer.

Price is valid for orders only while systems are available for refurbishment and is also contingent upon acceptance of Guild Associates' terms and conditions.

Warranty for equipment is valid for 15 months from shipment or 12 months from startup, whichever occurs first.

Operating Expense: The majority of the operating cost of the facility will be the power demand for the rotating equipment. Major maintenance costs include annual filter replacements and oil changes, materials cost of a plant of this scale is estimated at 2% of capital cost per year. The Molecular Gate media is fully regenerated in this process and media replacement is not expected during the lifetime of the equipment (20 years).

Estimated Duration: Equipment delivery is dependent on workload at the time order is placed, but is estimated to be between 5 - 7 months from receipt of purchase order.

We appreciate your interest in the technology.

Sincerely,

Paul Baker

Business Development
Phone: 614-760-8013
Email: paulbaker@guildassociates.com

Guild is a licensee of BASF's Molecular Gate™ Adsorbent Technology and is solely responsible for all representations regarding the technology made herein.

APPENDIX F

PERENNIAL ENERGY Thermal Oxidizer Quote

May 1st, 2019

Arcadis

Re: Mesa, AZ 200 SCFM Tail Gas Thermal Oxidizer Unit (TOU)

Attn: Shayla Allen, Andrew Deur

Shayla and Andrew:

Per your request, following and attached please find our **budgetary** quotation to supply the described products and services relative to your project requirements. We appreciate the opportunity to furnish this proposal.

PEI proposes to provide a unitized, modular, ***vertical*** thermal oxidizer (TOU) with a total capacity of **1.64 mmBtu/hr,** with off-loading and installation by others. The unit shall be sized per your request for quotation to handle **Condition #1:** 200 SCFM of waste gas stream at 5 % methane as well as the maximum supplemental fuel stream of **1,26 mmBtu/hr** or **20 SCFM** natural gas at a minimum of 10 PSI, at the **Condition #1** waste gas stream conditions. **Condition #2:** 70 SCFM of waste gas stream at 5% % methane as well as the maximum supplemental fuel stream of **.69 mmBtu/hr** or **11 SCFM** natural gas at a minimum of 10 PSI, at the **Condition #2** waste gas stream condition. TOU stability and economy will be dependent on a steady or slow change rate of waste flow and methane composition.

Connected **480 V motor HP** is: 1 x 3 HP package burner

Properties of the waste gas streams are assumed to be per your RFP.

The Thermal Oxidizer (TOU) shall include two principal sub-systems:

- The Thermal Oxidizer (TOU)
- The Thermal Oxidizer Control System

Not included in this proposal are the following:

- Freight, off-loading, or installation
- Site Civil, Structural, or Electrical Engineering
- Bonds or liquidated damages
- Taxes, permits, fees, etc.
- **Electrical interconnect between unit mounted J-boxes and main PLC cabinet.**

The Thermal Oxidizer(TOU) shall include:

- PEI **1.64 MMBtu/hr** TOU assembly for heat content of Waste Stream and 20 SCFM max natural gas supplemental fuel stream.

1375 County Road 8690 West Plains, MO 65775
Phone (417) 256-2002 Fax (417) 256-2801
www.PerennialEnergy.com PEI@PerennialEnergy.com

- ASTM A-36 carbon steel TOU shell assembly
- Approximate size: 4’ diameter (with reduced diameter stack extension) x 25’ O.A.H.
- Stainless steel protection band around top of TOU shell
- Stainless steel insulation retainer band and weather shield at top of TOU
- **Refractory i**nsulation, installed in overlapping layers. This results in 250 deg F skin temperature.
- Stainless steel retainer pins and keepers (washers) for insulation
- High temperature sealant/fixative solution sprayed on insulation
- Three (3) thermocouples at various heights (for temperature control) in unit shell
- Four (4) source test ports for air quality testing sensor access
- Five (5) view ports . . . one at each thermocouple and two to view main flame and pilot
- OSHA Ladder for access to thermocouples.
- Honeywell UV, self checking flame safeguard sensors
- Honeywell pilot ignition transformer mounted on unit
- Natural gas pilot line with solenoid, valve and pressure gauge
- Engineered structural mounting system
- Four (4) inches of air space beneath unit floor and equipment pad
- One each primary supplemental fuel process heating burner rated **1.26 MMBtu/hr** each. The burner will have a **3 HP** combustion air blower.
- Waste Stream entrance system
- 4” butterfly valve w/pneumatically controlled safety shutoff actuator w/spring assisted shutoff for the waste gas stream. Dry instrument quality compressed (80-100 psig) air supply by others.
- 4” aluminum flame arrester assembly w/ aluminum element. Handles the 90 deg. F max Guild waste gas stream.

Natural Gas Supplemental Fuel Line Valves and Devices:

- Standard natural gas fuel train for the one main power burner
- 1 each Thermal probe flowmeters for supplemental flow to the main burner

The Thermal Oxidizer Control System shall include:

- NEMA 4 control panel w/ NEMA 4 gasketing & 3 point latching
- NEMA 3/3R Weather / Heat radiation protection
- NEMA 3/3R **30 AMP 480** volt three phase Panelboard with branch breakers for all system loads.
- NEMA 3/3R MCC with motor starter for burner blower
- **5 KVA** 240/120 V transformer and low voltage distribution panel
- Control panel lighting
- Allen-Bradley Compact Logix PLC digital and analog logical supervision system with RSLogix 5000 version 20 or later. All specified alarms, shutdowns, and control functions
- C-More Touchscreen 6” Color
- Honeywell Burner Control Systems
- Alarm and shutdown message annunciation (Touch Screen)
- OFF / ON switch for the System
- TEST / CLOSED / AUTO switch for the safety shutdown valves
- TEST / OFF / AUTO switch for the burner control systems.
- Flame failure annunciation for the TOU (Touch Screen)
- Shutdown Valve failure annunciation (Touch Screen) for LFG system
- Flame failure reset (ALARM RESET / LAMP TEST switch)
- 480V three phase, 60 HZ Electrical service required **30 AMPS.**
- AC and DC control voltage surge protection

General:

- **One start up trip** of 3 days of on-site start-up & training services by a factory field services technician/engineer are included. To be accomplished in **one trip.**

- System is priced on an **FOB Factory, West Plains, MO basis**. Freight can be pre-paid and added to invoicing.

- 3 copies of full engineering submittals are included.

- 3 copies of "as-built" Operation & Maintenance Manuals are included.

The system as described above and attached is provided as completely pre-packaged, pre-wired, and factory pre-tested as is possible. ***The system is offered FOB Factory***, with freight billed at 115% of shipping invoice(s).

The pricing does not include any site civil or structural engineering, or site preparation work of any kind. Neither does the price include any local, state or federal taxes, or any permits, or tariffs of any kind. The system as quoted is to be off loaded, set in place, installed and interconnected by others.   The system includes only the standard PEI warranty for 18 months from date of shipment or 12 months from date of first service, whichever occurs first. Please see copy of PEI warranty, attached. We are pleased to honor this quotation for 30 days from the date of this document. The pricing is dependent on receiving an approved order that would include industry standard commercial terms. PEI standard terms are:

10% with order
30% with approved submittals
30% with receipt of major components
25% upon shipment
05% upon successful start-up, unless failure to achieve successful start-up
is neither the fault nor cause of PEI, then net 60 days of shipment

Budgetary Price……………………………………………………$175,000.00

We anticipate that we could deliver the system in **16-18** weeks from receipt of approved submittals or other irrevocable release to order all materials. Actual shipping estimates will have to be given at time of order. We anticipate that submittals can be provided in **3** to **4** weeks from receipt of an approved order.

Thank you for your consideration of PEI landfill gas products and services. Should you have any questions, or require further information in this regard, please do not hesitate to call.

Respectfully,

Brad Alexander
PERENNIAL ENERGY
Perennial Energy
West Plains MO 65775

APPENDIX G

Arcadis Expanded Cost Estimates

Mixed Slurry Offloading, Receiving, and Equalization Station Capital Expenditure Estimate					
Item Description	**Quantity**	**Unit**	**Total Unit Cost**	**nstallation & Labor Cos**	**Total Cost**
General Conditions/Division 1					**$ 31,000**
Truck Unloading					**$ 21,000**
Truck Unloading Goseneck	2	ea	$ 2,000	$ 1,000	$ 6,000
Card Reader and Metering Station	1	ea	$ 10,000	$ 5,000	$ 15,000
Pumps and Equipment					**$ 111,000**
Slurry Recirculation and Mixing Pumps	2	ea	$ 20,000	$ 10,000	$ 60,000
Slurry Recirculation Piping and Valves	1	ls			$ 15,000
Slurry Digester Feed Pumps	2	ea	$ 6,000	$ 3,000	$ 18,000
Level Sensor	1	ea	$ 5,000	$ 2,500	$ 7,500
Flow Meter	1	ea	$ 5,000	$ 2,500	$ 7,500
pH probe	1	ea	$ 2,000	$ 1,000	$ 3,000
Piping, Meterining and Valves					**$ 93,450**
6" Truck Unloading Pipe, DI	100	lf	$ 20	$ 40	$ 6,000
6" Fittings,DI	10	ea	$ 250	$ 400	$ 6,500
6" Knife Gate, DI	2	ea	$ 1,000	$ 500	$ 3,000
6" Recirculation/Mixing Pipe, HDPE	150	lf	$ 15	$ 20	$ 5,250
6" Fittings, HDPE	10	ea	$ 200	$ 400	$ 6,000
6" Plug Valve, DI	4	ea	$ 3,000	$ 1,500	$ 18,000
6" Check Valve, DI	2	ea	$ 3,000	$ 1,500	$ 9,000
4" Digester Feed Pipe, HDPE or PVC	500	lf	$ 20	$ 20	$ 20,000
4" Fittings, HDPE or PVC	20	ea	$ 135	$ 150	$ 5,700
4" Gate Valve	6	ea	$ 1,000	$ 500	$ 9,000
4" Check Valve	2	ea	$ 2,000	$ 500	$ 5,000
Electrical and Instrumentation Controls					**$ 60,000**
Lump Sum Electrical and INC	1	ls	$ 60,000		$ 60,000
Total Project Subtotal					**$ 317,000**
Contingency	30%				$ 95,000
Taxes, Bonds and Insurance	5%				$ 16,000
Overhead and Profit	15%				$ 48,000
Total Conceptual Construction Costs					**$ 476,000**

Low Pressure Compressor Capital Expenditure Estimate					
Item Description	**Quantity**	**Unit**	**Total Unit Cost**	**nstallation & Labor Cos**	**Total Cost**
General Conditions/Division 1					**$ 34,000**
Low Pressure Compressor					**$ 105,000**
2 psig, 200 scfm Compressor	2	ea	$ 30,000	$ 15,000	$ 90,000
Flow Meter	2	ea	$ 5,000	$ 2,500	$ 15,000
Piping, Meterining and Valves					**$ 101,000**
10" Biogas Pipe, SS	150	lf	$ 80	$ 20	$ 15,000
10" Fittings, SS	10	each	$ 1,200	$ 300	$ 15,000
10" Plug Valves, SS	2	each	$ 6,000	$ 2,000	$ 16,000
10" Check Valves, SS	2	each	$ 8,000	$ 2,000	$ 20,000
10" Isolation Valve, SS	2	each	$ 6,000	$ 1,500	$ 15,000
10" Three Way Recycle Valve, SS	2	each	$ 8,000	$ 1,500	$ 19,000
4" NG Pipe, pe	25	lf	$ 20	$ 20	$ 1,000
Gas Blending System					**$ 60,000**
Gas Blending System	1	ls	$ 60,000		$ 60,000
Electrical and Instrumentation Controls					**$ 40,000**
Lump Sum Electrical and INC	1	ls	$ 40,000		$ 40,000
Total Project Subtotal					**$ 340,000**
Contingency	30%				$ 102,000
Taxes, Bonds and Insurance	5%				$ 17,000
Overhead and Profit	15%				$ 51,000
Total Conceptual Construction Costs					**$ 510,000**

RNG Membrane Upgrading System and Pipeline Connection Capital Expense Estiamte							
			Material		Labor/Equipment		
Scope of Work	QTY.	Unit	Unit Rate	Cost	Unit Rate	Cost	Total Cost
General Conditions/ Division 1	1	LS					$ 218,000
Structural							
Concrete Slab for High Btu Skid (25'x10'x1' thick)	10	CY	$ 600	$ 6,000	$ 3,000	$ 3,000	$ 9,000
Mechanical							
Membrane RNG Conditioning System (400 scfm input capacity)	1	EA	$ 1,300,000	$ 1,300,000	$ 150,000	$ 150,000	$ 1,450,000
10" SS Digester Gas Piping	250	LF	$ 60	$ 15,000	$ 80	$ 20,000	$ 35,000
10" SS Digester Gas Fittings, Valves, and Metering	1	LS					$ 20,000
2" Buried HDPE Product Gas Piping	150	LF	$ 20	$ 3,000	$ 25	$ 3,750	$ 7,000
2" Buried HDPE Product Gas Fittings and Valves	1	LS					$ 5,000
Condensate Return and Chiller Piping	1	LS					$ 10,000
RNG to Pipeline Metering Station	1	LS					$ 75,000
Electrical and I&C							
Electrical - 15% of Mechanical Subtotal	15%						$ 240,000
I&C - 10% of Mechanical Subtotal	8%						$ 130,000
Total Project Subtotal							$ 2,197,000
Contingency				30%			$ 659,000
Taxes, Bonds and Insurance				5%			$ 110,000
Overhead and Profit				15%			$ 330,000
Total Conceptual Construction Costs							$ 3,296,000

Membrane System O&M Costs		
Maintenance Item	Annual Cost ($/year)	
Dryer Maintenance oil, grease	$	3,000
Inlet Separator Replace Element	$	1,500
Quarterly Maintenance on Feed Compressor-oil filter, samples	$	10,000
Annual Maintenance on Feed Compressor-add separator elements	$	4,500
Unplanned Maintenance (Estimated as 15% Planned Maintenance)	$	3,000
Total Annual O&M Costs	$	22,000

RNG PSA Upgrading System and Pipeline Connection Capital Expense Estiamte							
			Material		Labor/Equipment		
Scope of Work	QTY.	Unit	Unit Rate	Cost	Unit Rate	Cost	Total Cost
Division 1 Work - 11% of Subtotal	1	LS					$ 177,000
Structural							
Concrete Slab for High Btu Skid (25'x10'x1' thick)	10	CY	$ 600	$ 6,000	$ 3,000	$ 3,000	$ 9,000
Mechanical							
PSA Conditioning System (400 scfm input capacity)	1	EA	$ 995,000	$ 995,000	$ 150,000	$ 150,000	$ 1,145,000
10" SS Digester Gas Piping	250	LF	$ 60	$ 15,000	$ 80	$ 20,000	$ 35,000
10" SS Digester Gas Fittings, Valves, and Metering	1	LS					$ 20,000
2" Buried HDPE Product Gas Piping	150	LF	$ 20	$ 3,000	$ 25	$ 3,750	$ 7,000
2" Buried HDPE Product Gas Fittings and Valves	1	LS					$ 5,000
Condensate Return and Chiller Piping	1	LS					$ 10,000
RNG to Pipeline Metering Station	1	LS				$ -	$ 75,000
Electrical and I&C							
Electrical - 15% of Mechanical Subtotal	15%						$ 200,000
I&C - 10% of Mechanical Subtotal	8%						$ 100,000
Total Project Subtotal							$ 1,786,000
Contingency				30%			$ 536,000
Taxes, Bonds and Insurance				5%			$ 89,000
Overhead and Profit				15%			$ 268,000
Total Conceptual Construction Costs							$ 2,679,000

PSA System O&M Costs		
Maintenance Item	Annual Cost ($/year)	
Dryer Maintenance oil, grease	$	3,000
Inlet Separator Replace Element	$	1,500
Quarterly Maintenance on Feed Compressor-oil filter, samples	$	7,500
Annual Maintenance on Feed Compressor-add separator elements	$	4,000
Vacuum Pump quarterly maintenance-oil filter, oil sample greasing	$	10,000
Unplanned Maintenance (Estimated as 15% Planned Maintenance)	$	4,000
Total Annual O&M Costs	$	30,000

Thermal Oxidizer Capital Expense Estiamte							
Scope of Work	QTY.	Unit	Material		Labor/ Equipment		Total Cost
			Unit Rate	Cost	Unit Rate	Cost	
Division 1 Work - 11% of Subtotal	1	LS					$ 32,000
Structural							
Concrete Slab for TOX Skid (25'x8'x0.5' thick)	4	CY	$ 650	$ 3,000			$ 3,000
Mechanical							
Thermal Oxidizer System (200 scfm capacity)	1	EA	$ 175,000	$ 175,000	$ 50,000	$ 50,000	$ 225,000
Ancillary Piping and Equipment	1	LS				$ -	$ 20,000
Electrical and I&C Subtotal							
Electrical - 12% of Mechanical Subtotal	12%						$ 29,000
I&C - 7% of Mechanical Subtotal	7%						$ 17,000
Total Project Subtotal							$ 326,000
Contingency				30%			$ 98,000
Taxes, Bonds and Insurance				5%			$ 16,000
Overhead and Profit				15%			$ 49,000
Total Conceptual Construction Costs							$ 489,000

Arcadis U.S., Inc.
410 N. 44th Street
Suite 1000
Phoenix, Arizona 85008
Tel 602 438 0883
Fax 602 438 0102

www.arcadis.com