Rochester Water Reclamation Plant

2019 Facilities Plan

Technical Memorandum 8: Digester Gas Management

TM 8 of 13 | J4325

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Technical Memorandum

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Project Title: Water Reclamation Plant Facilities Plan

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Subject: Digester Gas Management

Date: September 11, 2019

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List of Abbreviations

°F	degree(s) Fahrenheit
AACEI	Association for the Advancement of Cost Engineering International
BACT	best available control technology
BC	Brown and Caldwell
BCE	business case evaluation
Btu	British thermal unit(s)
ccf	100 cubic feet
cfm	cubic foot per minute
CH_4	methane
CHP	combined heat and power
City	City of Rochester
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
DG	digester gas
ft^3	cubic foot/feet
FTE	full-time equivalent
GGE	gasoline gallon equivalent
H_2S	hydrogen sulfide
HEX	heat exchanger
HHV	higher heating value
hr	hour(s)
HSW	high-strength waste
HVAC	heating, ventilation, and air conditioning
K	thousand
kW	kilowatt(s)
kWh	kilowatt-hour(s)
lb	pound(s)
LHV	lower heating value
M	million
max	maximum
MERC	Minnesota Energy Resources
min	minimum
MMBtu	million British thermal units
MW	megawatt(s)
N_2	nitrogen
N/A	Not Applicable
NG	natural gas
NO_x	nitrogen oxide
NPV	net present value
O_2	oxygen
O&M	operations and maintenance
ppbv	part(s) per billion by volume
ppmv	part(s) per million by volume
psi	pound(s) per square inch
psig	pound(s) per square inch gauge
QAP	Quality assurance plan
RFS2	Renewable Fuel Standard 2
RH	relative humidity
RIN	Renewable Identification Number
RNG	renewable natural gas
scfm	standard cubic foot/feet per minute
TM	technical memorandum
TS	total solids
USEPA	United States Environmental Protection Agency
w.c.	water column
WRP	water reclamation plant
WWTP	wastewater treatment plant
yr	year(s)

Executive Summary

As part of the City of Rochester (City) Facilities Plan for the Rochester Water Reclamation Plant (WRP), this task provides a business case evaluation (BCE) of potential digester gas (DG) utilization technologies. The DG is currently used to fuel one of the WRP's two, 1-megawatt (MW) Waukesha engine generators or hot water boilers. The WRP runs the engine generators on DG for 7 months of the year when plant heating demand is lower (summer) and prioritizes the DG use in the boiler during the winter when heat demands are high. Various DG alternatives were developed and evaluated to determine if any alternatives could provide economic benefit over the current operation of biogas-fired boilers and engine generators. The list of biogas utilization alternatives considered included:

- Continued use of engine-generators with replacement units installed around 2027
- Replacing the engine generators with microturbines for combined heat and power (CHP) production
- Producing compressed renewable natural gas (RNG) for pipeline injection
- Producing RNG for use as an on-site vehicle fuel

Practical considerations are likely to eliminate some of the alternatives from further consideration:

- The on-site vehicle fueling alternative produces approximately 1,700 gasoline gallon equivalents (GGEs) per day of compressed natural gas (CNG). A large fleet with CNG-fueled vehicles, such as a municipal transit buses or garbage trucks, would be required to utilize this fuel. In addition, the trucks would require access to the site for fueling, which may be disruptive to the adjacent neighborhood.
- There are only two manufacturers that provide microturbines, limiting the ability to secure long-term parts, support, and competitive procurement. Capstone is the only vendor with a track record of operating on DG and their financial status and recent warrantee performance is concerning.

The results of the DG utilization BCE indicate that beneficially using DG via pipeline injection and Renewable Identification Number (RIN) contracting can provide economic benefit over the current DG operating scenario if RIN pricing remains at current (or better) levels over the life of the project. The pipeline alternative has the following advantages for the Rochester WRP relative to other DG utilization alternatives:

- Reduced maintenance costs
- Wide range of turndown for variable DG flow
- Potential for external investment partners or developers

In addition to the CHP and RNG alternatives listed above, the economics of adding DG siloxane treatment upstream of engine generators were evaluated. While net O&M costs with siloxane removal are expected to be lower than existing costs, the reduction is not sufficient to justify the estimated capital cost.

Section 1: Introduction

1.1 Objective

Figure 1-1 illustrates the relative value of DG end uses compared to other energy commodity prices. As seen in this figure, the current value of pipeline natural gas (NG) is relatively low, while RIN revenue (described in greater detail in section 4.2.5) from biogas upgraded to RNG is high under current market conditions. In municipalities with lower electric utility costs similar to the City, the value of electrical output of a biogas CHP system is generally higher than the NG value, but less than the vehicle fuel value. The intent of this BCE is to determine whether the potential revenues for these higher-value biogas products are sufficient to justify the capital expenditures.

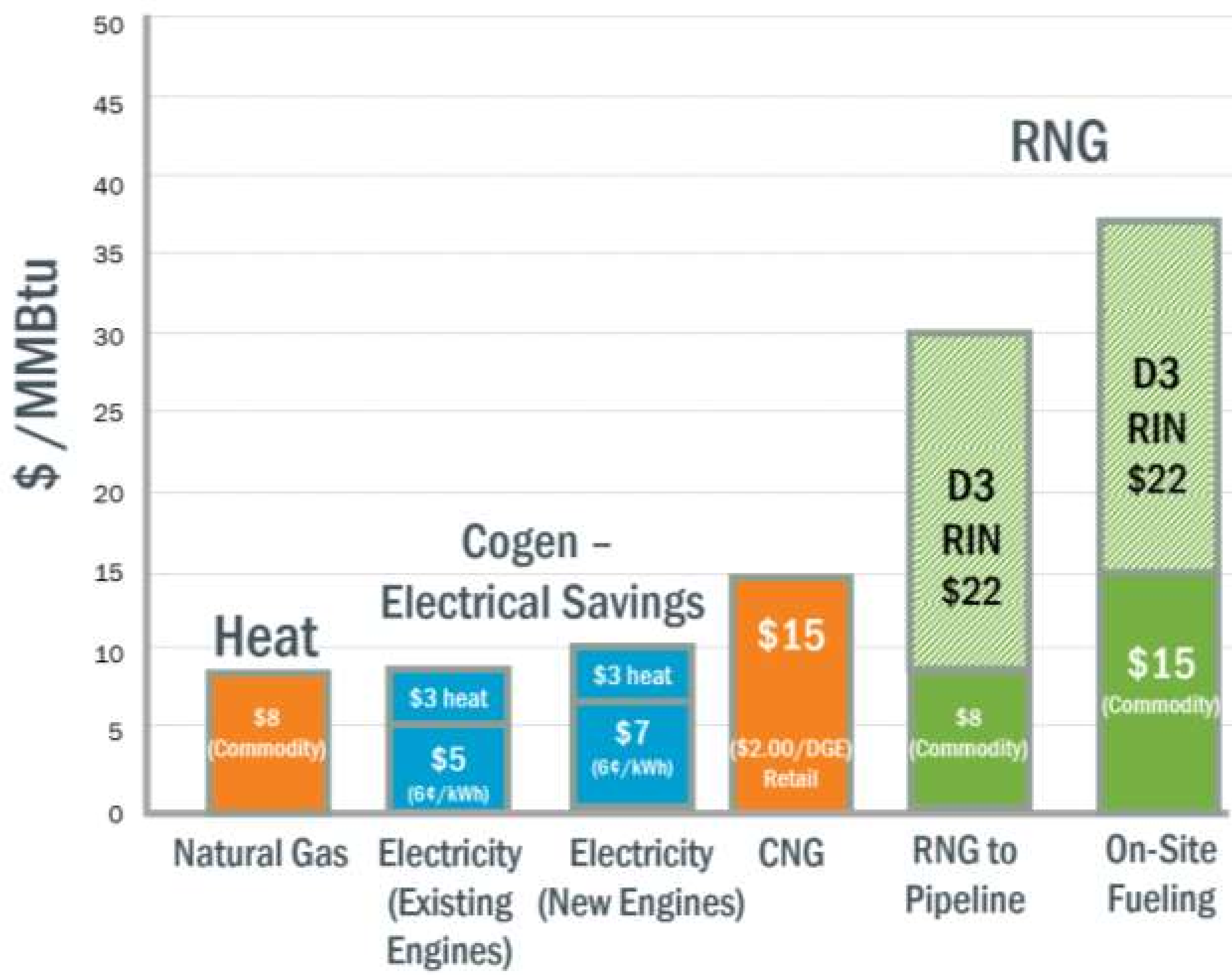


Figure 1-1. Relative value of DG as various end uses (average commodity prices in Rochester area)

D3 RIN = cellulosic biofuel RIN credit under Renewable Fuel Standard 2 (RFS2) program.

$0.06/kWh for electricity assumes no demand savings as described in section 4.2.3.

O&M costs not accounted for in graph – only estimated cost savings or revenue.

RNG to pipeline does not include injection tariff or devalued commodity sale price.

1.2 Report Format

This Technical Memorandum (TM) considers alternative DG utilization approaches and uses NPV analysis to determine if any alternatives could provide economic benefit over the current operation of biogas-fired boilers and engine generators. The TM is organized into the following sections:

- Section 1: Summary of existing system
- Section 2: Current DG flow and quality, and heating demand
- Section 3: Review of available utilization technologies
- Section 4: NPV comparison of utilization alternatives and cost benefit assessment of siloxane removal equipment
- Section 5: Summary and recommendations

1.3 Existing DG System

The following sections summarize the major components of the existing WRP DG system and related DG utilization components.

1.3.1 DG Management System

The Rochester WRP currently generates DG from active digesters (No. 1, 5, and 6) at approximately 5.5 to 8 inches w.c. Standalone low-pressure gas holders are used to store short term excess DG but are corroded with one out of service and the other near the end of its service life. Low pressure gas is routed to one of two booster blowers, which increase the DG pressure to approximately 5 to 6 pounds per square inch (psi) for use in the CHP and boiler systems.

A high-pressure DG storage sphere is used to store gas when the available quantity of gas exceeds the demand from the utilization equipment, including diurnal cycles. The high-pressure gas compressor boosts the DG pressure to approximately 10 to 45 psi for storage. Pressure reducing valves control the flow of stored gas back into the DG utilization system. Management of DG utilization and use of this high-pressure storage equipment generally allows the WRP to avoid flaring DG.

1.3.2 DG Treatment

Ferric chloride dosing in the anaerobic digesters for struvite control keep DG hydrogen sulfide (H_2S) levels low. Moisture is removed in a 2-stage system. The first stage heat exchanger (HEX) uses plant effluent for cooling to around 67 degrees Fahrenheit (°F). The second stage HEX uses chilled water to cool the DG to 40°F to 45°F. A gas-to-gas reheat system uses hot gas from the low-pressure blower discharge to increase the DG temperature to 63 °F, which lowers the relative humidity of the DG. The chilling and moisture removal systems remove some siloxanes, but not as much as an activated carbon system, which is designed to remove all siloxanes. High pressure gas is routed through a particulate filter with w/ low temperature loop aftercooler to bring temperature down to approximately 67 degrees F and does not route through the chiller HEX.

1.3.3 Engine-generators

The WRP has two 1 MW Waukesha engine generators as summarized in Table 1-1. One engine is typically in service between May and November, with the second unit serving as a stand-by. The existing engines are only operating at 60 percent of full load based on the quantities of DG available and have a relatively low electrical efficiency. The WRP is planning a control system upgrade for the Waukesha units to improve reliability.

The WRP has a curtailment agreement with Rochester Public Utilities that requires the WRP to operate the engine units occasionally in the winter and summer. These curtailments are triggered by low NG supplies that constrain the city's natural gas power generating capacity or excessive energy demand. The WRP receives an electric billing credit of $4160 per month for providing this curtailment service.

Table 1-1. Biogas Engine Generators

Criterion	Waukesha 1	Waukesha 2
Model	VHPL5794LT	VHPL5794LT
Installation year	2003/2004	2008
Run hours	46,000	41,000
Electrical efficiency	29%	
Thermal efficiency	39%[a]	

a. Thermal efficiency derated from nameplate value for siloxane fouling in exhaust heat recovery unit. Typical engine generators can recover 40 to 49 percent of the waste heat with clean heat exchange surfaces.

1.3.4 Boilers

All DG is burned in Boiler Nos. 3, 5, 6, and 7 during the winter months due to higher space heating demands. Additional NG is purchased to meet the WRP's heating demands during the winter months at approximately $10,000 annually. The WRP has determined that the net energy costs associated with using biogas in their boilers during winter months is less than running the CHP system all year because savings from electrical production do not offset the increased natural gas cost to satisfy plant heat demands and added engine-generator O&M.

1.4 Basis of Evaluation

This section summarizes the estimated size of existing energy flows that were used in the BCE, including:

- Biogas production and quality
- Process and space heat demand

1.4.1 Biogas Production

DG flow meter data was used to estimate current (baseline) DG production. DG flows were available for biogas production from Digesters 1, 5, and 6 from January 1, 2014 to December 31, 2017. Growth in solids production, increased VSR with gravity thickening, and high strength waste addition are likely to increase future DG flow rates, however, the change from HPO to A/O will reduce expected VSR which would counterbalance some of increase in DG production. For simplicity, this increase was not included in this analysis. Any future increases in biogas production will tend to improve the economic viability of all biogas utilization alternatives.

There is an old landfill adjacent to the WRP, but this evaluation assumes no landfill gas is available to supplement the DG as staff has noted no methane detection coming out of existing vents.

DG production is continuously measured on each DG lateral and recorded in the WRP's SCADA system. Daily DG production rates averaged 272 standard cubic feet per minute (scfm) and ranged between 180 and 368 scfm (with upper and lower 1 percent of data points excluded). Figure 1-2 shows the variation in total metered DG production over the baseline period. The NPV analysis in Section 3 is based on the average DG production rate.

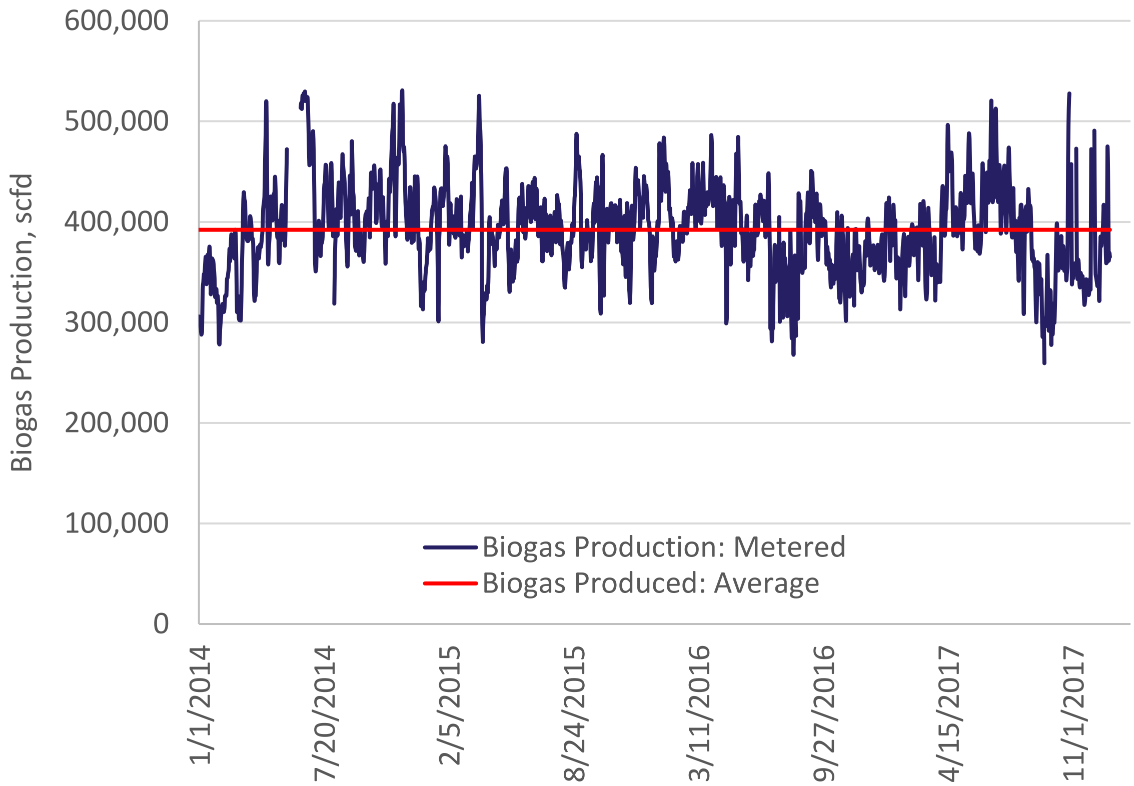


Figure 1-2. Metered DG production (January 1, 2014 to December 31, 2017)

1.4.2 Biogas Quality

Lab analysis from two recent gas samples taken after the moisture removal HEX indicated the WRP DG has relatively low contaminant levels (H_2S and siloxanes; summarized in Table 1-2). If these two samples are representative, conventional gas treatment costs for end use in cogeneration or for DG upgrading should be in a normal range. Additional future sampling will help refine the gas treatment system design and projected operating costs.

Table 1-2. DG Sample Lab Results			
Parameter	Unit	Rochester WRP Value [a]	Typical Municipal WWTP Value
CH_4	Volume percent, dry	60.3	55–65
CO_2	Volume percent, dry	31.3	35–45
O_2	Volume percent, dry	0.35	0–1
N_2	Volume percent, dry	1.14	0–2
LHV	Btu/ft^3	550	550–610
HHV	Btu/ft^3	615	610–680
H_2S	ppmv	56 [b]	20–2,000
Total siloxanes	ppmv	0.35 [c]	0.3–6

a. *Two DG samples (11/17/2014 and 06/22/2015) averaged. Gas quality can vary, and higher concentrations will affect gas treatment cost and O&M hours.*

b. *With ferric chloride dosing in primary clarifiers and digesters.*

c. *Raw DG siloxane concentration would be higher because some siloxanes have been removed in the moisture removal system.*

1.4.3 Process and Space Heat Demand

The process heating demands of the digesters must be met by each alternative either via DG, NG, or CHP heat recovery. Digester heating requirements are approximated using the annual average digester flows and are presented in Table 1-3.

Table 1-3. Estimated Digester Heating Demands			
Parameter	Summer, MMBtu/hr	Winter, MMBtu/hr	Annual Average, MMBtu/hr
Sludge heating [a]	1.1	1.9	1.4
Shell losses	0.2	0.6	0.4
Total digester heating demand with future gravity thickening	1.3	2.5	1.8
Current digester heating demand without gravity thickeners	1.9	3.3	2.5

a. *Based on current digester loadings and 5 percent TS digester feed following gravity thickener upgrades*

In addition to digester heating, space heat is required in several of the buildings during the winter. Figure 1-3 shows the heating, ventilation, and air conditioning (HVAC) demands from January 3, 2018 to February 10, 2019. This heating demand is met by the boiler and engines and does not include the heat provided by the low temperature and other heat recovery loops.

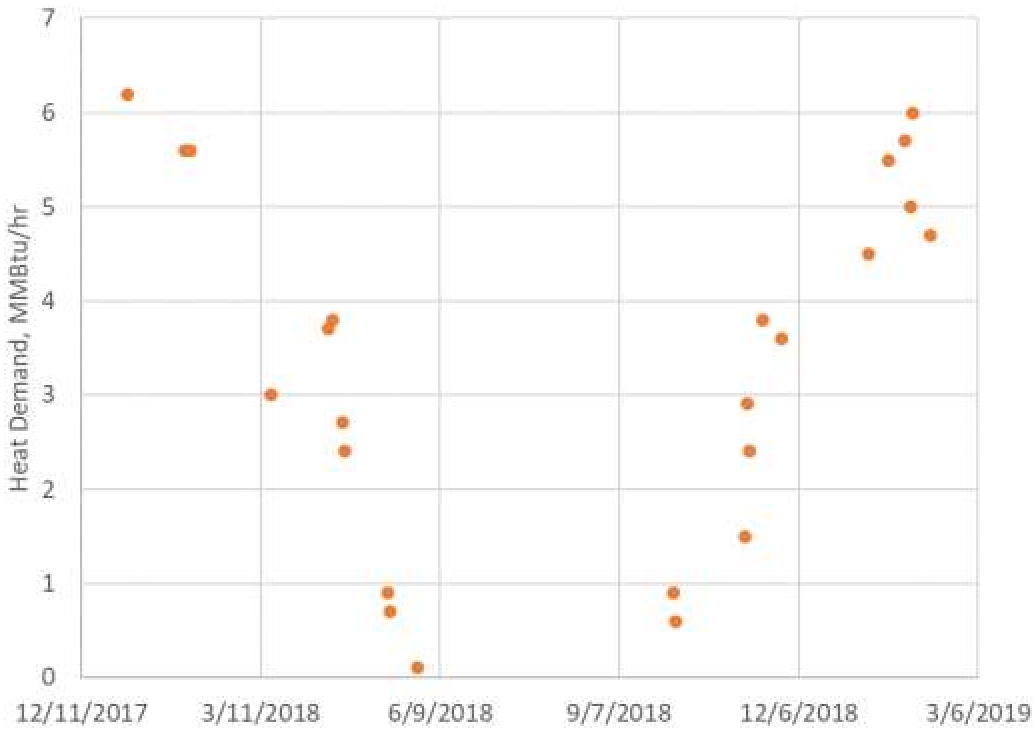


Figure 1-3. HVAC demand (January 3, 2018 to February 10, 2019)

Source: City of Rochester.

Average heat demand was calculated based on NG bills and the expected heat output from the boilers and engines, as shown in Table 1-4. Total thermal production was then calculated from utilizing DG in the engines and boilers, and adjusted to reflect the reduced heat demand with a future gravity thickener. Each alternative evaluated in Section 3 will be modeled to produce a total of 5.2 MMBtu per hour of heat for the digesters and HVAC demands, using CHP heat recovery, DG-fueled boilers, or NG-fueled boilers (vehicle fuel options).

Table 1-4. Estimated Total Plant Heating Production

Fuel Source	Heat Production Technology	Months/Year Operation	Heat Production, MMBtu/hr	Weighted Annual Average, MMBtu/hr
NG bills	Boiler	5	1.5[a]	0.6
DG	Boiler	5	9.0	3.8
DG	Engine	7	2.7	1.6
Total current thermal production	Engine + Boiler	12	N/A	6.0
Reduction in heat demand for GT	-	-	-	0.7
Future total heat demand	-	-	-	5.2

a. *Derived from monthly NG billing records (2012-2017) and 82 percent boiler efficiency.*

b. *Engine thermal efficiency of 39% assumed (derated for siloxane accumulation in exhaust). Typical engine generators can recover 40 to 49 percent of the waste heat.*

Section 2: DG Alternatives Analysis

Table 2-1 lists the alternatives evaluated in this TM and a description of each alternative's major process components. The list includes two CHP alternatives (engines and microturbines) and two gas upgrading alternatives (pipeline injection and on-site fleet fueling). The status quo alternative envisions continues IC engine use, but reflects engine replacement (and salvage value) as part of the net present value analysis.

A brief review and comparison of these alternative utilization technologies is provided in this section, beginning with the gas conditioning technologies common to all alternatives.

Table 2-1. DG Utilization Alternatives

Alternative	Description/Major Components
Status quo	• Matches current operation (one or two 1 MW replacement) • DG is sent to the engines and boilers (approximately 5 months per year to boilers) • Engine replacement 2027 • Limited gas conditioning (moisture removal) in near term, siloxane removal installed with new engine
Microturbines with heat recovery and siloxane removal	• Microturbines replace engines (five 200 kW units) • Siloxane removal and gas compression up to 80 psig • DG is sent to the microturbines and boilers (approximately 5 months per year to boilers)
DG upgrading to pipeline injection	• All DG sent to produce RNG: 400 scfm capacity DG upgrading system • Pipeline interconnection and injection into NG utility pipe • NG purchased to run boiler to provide digester heat and process space heat
DG upgrading with on-site vehicle fueling	• All DG sent to produce RNG: 400 scfm capacity DG upgrading system • Onsite CNG fueling station for fleet (e.g., solid waste trucks, city buses) • NG purchased to run boiler to provide digester heat and process space heat

2.1 DG Conditioning

Figure 2-1 presents a process flow schematic for a conventional DG conditioning system. Gas conditioning system components are briefly discussed in this subsection.

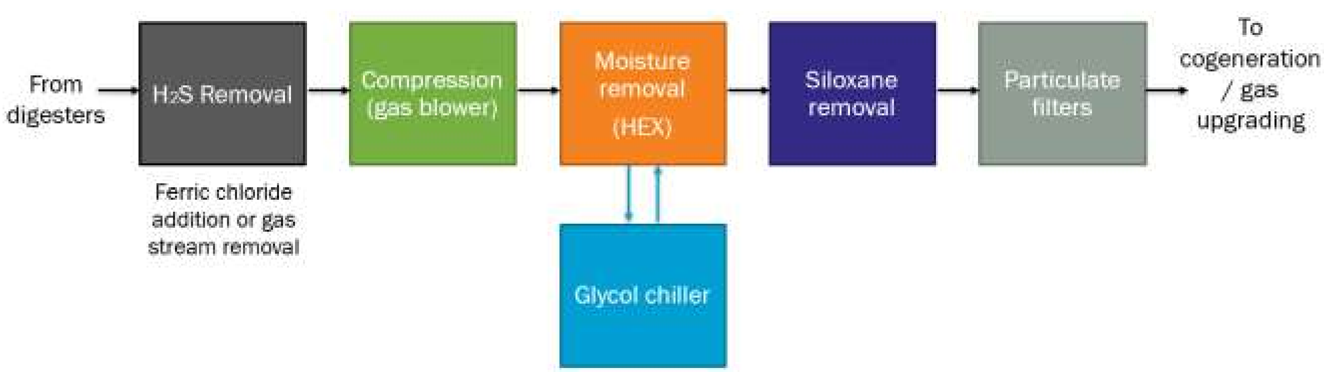


Figure 2-1. Process flow schematic for DG conditioning system

Figure 2-2 shows the gas conditioning system at the Columbia Boulevard Wastewater Treatment Plant (WWTP) in Portland, Oregon, where two 850-kilowatt (kW) engine-generators are installed.

Figure 2-2. DG treatment system, Columbia Boulevard WWTP

Source: Jim Brown, Cliff Meier, "Anaerobic DG Cogeneration Technology," PNCWA 2009.

2.1.1 H_2S Removal

Because the H_2S concentration in the WRP's DG is low due to upstream ferric chloride dosing, a dedicated H_2S removal system is not required for use in engines, microturbines, or DG upgrading. However, if siloxane removal is installed in the future, the residual H_2S will compete for activated carbon pore sites with the siloxanes and shorten the siloxane media life. The operations and maintenance (O&M) benefit of upstream H_2S polishing for extending siloxane media life could be evaluated in conjunction with any future siloxane installation.

H_2S and other sulfides are typically removed from warm, moist DG using packed-bed vessels to prevent corrosion and reduce sulfur oxide emissions from combustion sources. The packing can be (1) iron sponge material, which consists of iron-oxide-impregnated wood chips, (2) special potassium iodide impregnated carbon media, or (3) a specialized granular iron-impregnated media such as SulfaTreat. Iron sponge media typically has the lowest life-cycle costs, but the media is more difficult to remove from the vessels than a specialized media as it tends to "cement" together over time. Iron sponge media agglomeration is especially problematic in installations like the WRP with low H_2S concentrations and infrequent media changes, so H_2S-specific activated carbon and granular carbon media would be preferred if a polishing step is installed.

2.1.2 Compression and Moisture Removal

DG must be boosted in pressure to overcome the pressure losses of the gas treatment system and supply enough pressure for the end use. The DG pressure is boosted by a blower or compressor, which also adds heat to the DG. The existing WRP low pressure compressors are assumed to be suitable for continued use for the status quo option.

Moisture is removed from the DG to help prevent engine damage from condensing water droplets. Engine manufacturer's gas quality specifications typically require less than 80 percent relative humidity (RH) to protect the fuel train and cylinders. In addition, effective moisture removal prolongs siloxane media life because moisture competes with siloxanes for activated carbon pore sites (similar to H2S).

Following compression, water is typically removed by cooling the DG to around 35°F in a HEX, forcing moisture to condense. The existing WRP HEX system does not reach 35°F because icing occurs if the chilled water temperature is lowered, so the dewpoint is slightly higher than ideal.

Once the gas dew point is lowered, the cold gas is typically reheated using the incoming hot blower discharge flow so that the gas is no longer saturated. This reheating process improves the effectiveness of the downstream siloxane removal media, reduces the RH of the DG, and is used to set a relatively constant downstream gas temperature.

2.1.3 Siloxane Removal

DG contains various species of siloxanes commonly found in household and personal-care products such as deodorants and lotions. When DG and siloxanes are combusted in an CHP engine or boiler, the siloxanes oxidize to form silica particles that can build up and cause significant damage to CHP engine components and exhaust catalysts (if used).

The need for siloxane treatment varies somewhat between DG utilization technologies:

- Microturbines are most sensitive to siloxanes and generally require 5 parts per billion by volume (ppbv), which is often below detectable levels; therefore, continuous effective siloxane removal is required to protect microturbine equipment.
- To meet RNG specifications, siloxane removal is required upstream of gas separation membranes for pipeline injection and on-site vehicle fueling alternatives.
- Newer high efficiency engine-generators are virtually always installed with siloxane removal. The status quo BCE alternative assumes that siloxane removal will be installed to serve new engines.

A typical siloxane removal system would consist of two activated carbon vessels operated in series. Because siloxanes are not readily measured in the field, series operation allows for the development of a systematic approach to operating the tanks and timing media replacements to minimize carryover of siloxanes downstream.

Section 3.4 considers whether siloxane removal should be installed in the near term, prior to the engine replacement. Brown and Caldwell (BC) questioned the City regarding the impact of siloxanes on CHP O&M. These questions are summarized in Table 2-2. The intent of these questions was to inform the estimate of O&M savings used in the near-term siloxane treatment evaluation.

Table 2-2. Impact of Siloxanes on Engine Maintenance

BC Questions	City Responses	Significance
Frequency of oil changes?	900 hours	WWTP oil change frequency is often 1,000-1,500 hours which may suggest oil WRP changes could be extended slightly with siloxane removal.
What triggers the oil change? Silica in the oil testing or another metric?	Not completely silica, still trying to reduce oil change frequency, but the acid and silicon will both be limiting factors.	
Is spark plug life decreased from silica deposits?	Not so much from what we've seen.	No O&M savings from spark plug changes.
Does the exhaust heat recovery unit require cleaning of silica deposits? Has it been inspected to check for fouling?	Yes, but has not been cleaned that often, it does foul but not completely, efficiency is just reduced.	Siloxane removal would benefit with greater exhaust heat recovery.

Table 2-2. Impact of Siloxanes on Engine Maintenance		
BC Questions	City Responses	Significance
Other gas treatment notes	The mechanics have noticed that since the addition of ferric chloride, black residue can be found in the chilled water HEX, condensate drains, and engine generator methane gas sock filters. However, siloxanes on the pistons and wear on the cylinders has been reduced significantly since the chilled water HEX was installed and ferric chloride addition to the digesters was increased. Although methane gas sock filter replacement has increased significantly, overall wear on the generators has been significantly reduced.	Sock filters used to be changed once every couple years and now require changing every other oil change. Heavier siloxanes and VOCs may be removed from the gas with the condensate in the chilled water HEX.
Any piston damage related to silica deposits?	Yes, this is where we see the most damage. Our piston heads have deposit buildup on them and then this in turn leads to wear.	Some O&M savings are possible, including a possible extension of the overhaul interval.

2.2 Cogeneration

Cogeneration systems generate on-site electrical power and useful thermal energy, allowing for overall combined electrical and thermal efficiencies of up to 85 percent. Common prime movers for small to medium cogeneration systems include engine generators and microturbines, discussed in this subsection.

2.2.1 Engines

For the NPV analysis in Section 3, the two existing Waukesha units are assumed to be replaced with 1 MW engine generators at the end of their useful life, estimated year 2027. Current high-efficiency engine generators are more efficient than the existing Waukesha units (roughly 39 versus 29 percent), so the future average CHP output would increase to 1,027 kW. Based on equipment datasheets of engine generators sized at approximately 1 MW, the associated electrical efficiencies (full output rating) are as follows:

- Cummins 1,000 kW: 41.5%
- GE Jenbacher 1059 kW: 39%
- Dresser Rand 1040 kW: 41.5%
- Caterpillar 1015 kW: 36.1%
- Waukesha 1100 kW: 40.9%

Table 2-3 reviews engine sizing options that should be considered by the City during any future engine selection process and Table 2-4 shows the estimated potential heat recovery from each heat source. Replacing the existing engines with 1 MW units will not provide sufficient capacity based on the expected quantity and quality of DG, assuming high-efficiency engine models are selected.

Table 2-3. Proposed Engine Fuel Consumption				
Engine Selection	Operating Units	Proposed Gross Engine Output(kW)	Proposed Net Engine Output (kW)	Load at Current Average Available DG (percent)
2 at 1,000 kW	1 at 1,000 kW	1,027	965	103
2 at 1,100 kW	1 at 1,100 kW	1,027	965	93
2 at 1,200 kW	1 at 1,200 kW	1,027	965	86

Table 2-4. Estimated Engine Heat Recovery at 100 Percent DG Utilization[a]				
Engine Selection	Jacket Water (MMBtu/hr)	Exhaust (MMBtu/hr)	High Temperature Total (MMBtu/hr)	Lube Oil (Low Temperature) (MMBtu/hr)
Existing	1.74	1.74[b]	3.48	0
New	2.31	1.74[c]	4.05	0.40

a. *Based on Siemens SGE-56HM, 1040 kW engine generator at 1200 rpm operating on digester gas.*

b. *Assumes some heat exchanger fouling*

c. *Clean heat exchanger*

2.2.2 Microturbines

Microturbines are small combustion turbines that cogenerate heat and electricity and are generally compact, modular, and low-emission, with less ancillary equipment and routine maintenance than engines. Packaged microturbine units are available in capacities ranging from 65 to 333 kW per unit. They are capable of NG blending to increase power output during on-peak electrical rate periods or when the plant electrical demand is greater. In addition, because microturbine systems are modular, they allow for greater flexibility to match the available DG fuel, although the modular configuration also means more units to maintain. Microturbines have a relatively small footprint and are anticipated to fit in the existing engine building along with the heat recovery equipment. Figure 2-3 shows a microturbine package installation with three 65-kW units and Figure 2-4 shows how the existing engine room could be retrofitted with microturbines.

Figure 2-3. Example microturbine installation with integrated exhaust manifold

Source: Capstone

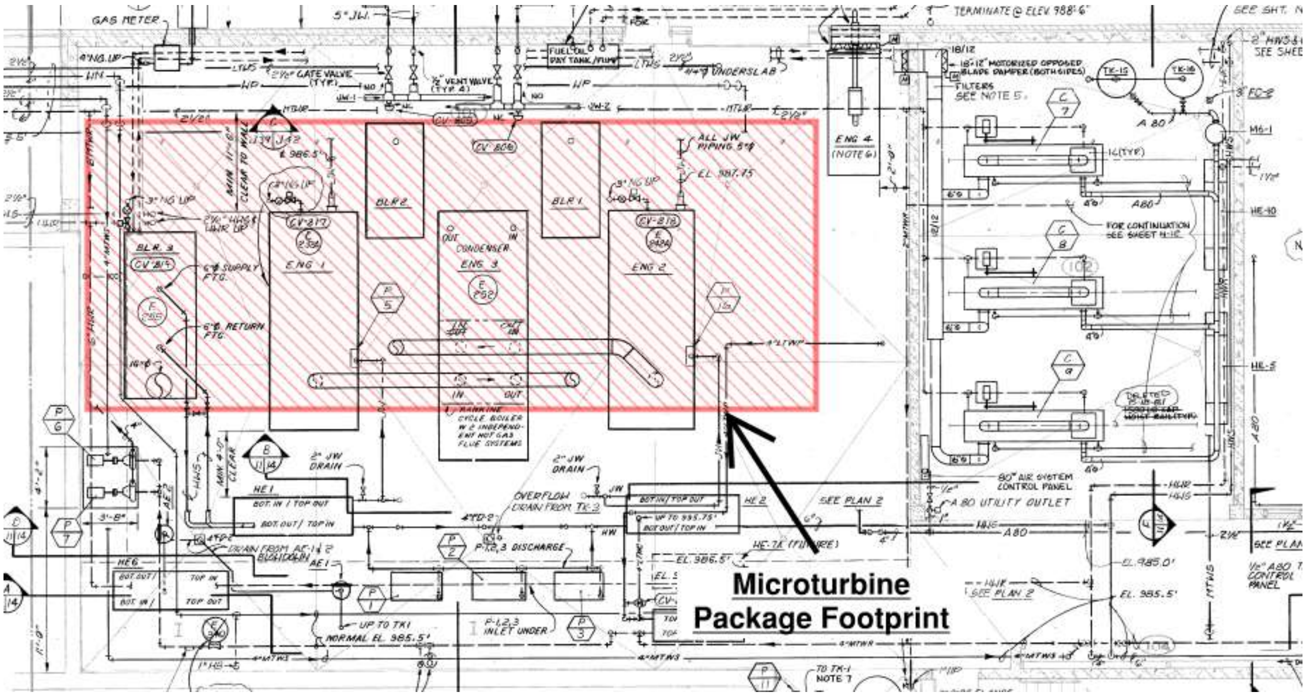


Figure 2-4. Microturbine and associated heat recovery equipment layout retrofitted in existing Engine Room.

Additional space will be required for hot water pumps, heat recovery unit, and gas compressor.

Microturbines have a few significant disadvantages:

- There are only two main microturbine manufacturers in the United States, Capstone and FlexEnergy. FlexEnergy purchased Ingersoll Rand's microturbine business and has few wastewater installations. Either vendor could provide a microturbine system based on the WRP's gas production (approximately 820 kW output). Neither vendor has significant financial resources, and there is a risk that long-term product support may not be available. The limited service support must be considered if this technology is ultimately selected.
- Microturbines are extremely sensitive to siloxanes and require gas conditioning to remove sulfides, moisture, and siloxanes and need compression up to 80 pounds per square inch gauge (psig). Due to the small passageway within the recuperator and the large surface area of siloxanes, siloxanes must be monitored frequently (i.e., monthly) to prevent them from entering the recuperator. Siloxane tests are conducted by sending samples to a laboratory and cost approximately $250 per sample.
- Typical electrical efficiency is lower than an engine at approximately 31 percent (newer advanced engines have electrical efficiencies of up to 42 percent).
- Microturbines have a lower thermal efficiency and typically can recover less heat than an engine.
- Microturbine output capacity drops significantly in warm weather.

Several WWTPs in the United States operate Capstone microturbines including Janesville, Wisconsin; Albert Lea, MN; Sheboygan, Wisconsin; Durango, Colorado; Persigo, Colorado; Ithaca, New York; and Santa Margarita, California—all of which have reported successful operation. However, a more recent installation in Dubuque, Iowa encountered challenges with poor manufacturer support.

2.2.3 Comparison of Cogeneration Technologies

At the Rochester WRP, the moderate quantities of DG available can be suitable for engines or microturbines. Table 2-5 provides a brief overview of the key differences between microturbines and engines as discussed in this section.

Table 2-5. Comparison Between Microturbines and Engines

Category	Microturbines	Engines
Capital costs	Lower in comparison to engines	Higher in comparison to microturbines; more ancillary equipment required such as a radiator, lube oil, HVAC, and inertia block. Ancillary equipment requires more footprint, piping, instrumentation and controls, and electrical.
Sizing	30, 65, 200, 250, and 333 kW units	60 kW to >2 MW
Electrical efficiency	28–32% (low)	Existing Waukesha: 29% New: 35–42% (moderate to high)
Thermal efficiency	20–25% (low)	Existing: 39% (moderate) New: 40–49% (moderate to high)
Maintenance requirements	Approximately 5% downtime for maintenance Moderate maintenance costs. Long term maintenance support from manufacturers and third parties questionable.	5–10 % downtime for maintenance Moderate to high maintenance costs Requires continual cooling
Turndown	Can tolerate some turndown (to 50% of full load)	Can tolerate some turndown (50 to 60% of full load)
Fuel requirements	H_2S (depending on raw DG properties), siloxane, and moisture removal Medium fuel gas pressure required (80 psig)	Hydrogen sulfide, siloxane, and moisture removal Low fuel gas pressure required (3 to 5 psig)
NG blending	Available in manufacturer's scope of supply	Available in manufacturer's scope of supply
Noise	Fairly quiet	Loud
Permitting	Lower emissions	Moderate exhaust emissions; may require exhaust treatment
Manufacturers	Capstone, Flex Energy	Caterpillar, MTU, GE Jenbacher, Cummins, Dresser Rand, Waukesha
Parasitic loads	8% of gross output	6% of gross output
Estimated net electrical output for NPV evaluation (at average DG production)	750 kW	690 kW (current Waukesha) 1,030 kW (future)

2.2.4 Emissions and Air Permitting Considerations

Olmstead county is currently considered to be in "maintenance" status from an air quality standpoint, so it is treated as being in attainment. The attainment status means that a new engine generator is unlikely to be required by the MPCA to meet Best Available Control Technology (BACT) standards, reducing the likelihood that an oxidation catalyst or selective catalytic reduction (SCR) system would be required. As a recent example, WLSSD is currently bidding a new engine-generator and no exhaust treatment is included. If an engine replacement project is pursued in the future, regulatory requirements would have to be confirmed with the MPCA.

Because microturbines produce low nitrogen oxides (NO_x) and carbon monoxide (CO) emissions in comparison to an internal combustion engine, they may not require an air permit, or a permit may be less difficult to obtain.

2.3 DG Upgrading

DG upgrading produces biomethane, an RNG substitute that can be used in vehicles fueled by CNG. Under current RIN market conditions, DG upgrading alternatives that provide RIN revenue can have better economic performance than CHP alternatives. RNG is routed to either a pipeline injection system and transferred to an end user or is stored and dispensed as on-site vehicle fuel. Participation in the RIN market is possible with both alternatives, providing a physical pathway from the location of injection to the CNG offtake station can be mapped.

2.3.1 DG Upgrading Description

Several DG separation technologies are available including membranes, pressure swing adsorption, and water solvents. Figure 2-5 shows a small DG upgrading system provided by Unison Solutions that uses membrane separation. Other typical DG separation technology manufacturers include Air Liquide, Guild, Morrow Renewables, and Greenlane. Given the DG upgrading equipment capacity required for the DG flows at the Rochester WRP, the membrane technology is the best apparent technology based on a low capital cost, high methane recovery rate, and moderate power requirements. Capital costs for the DG upgrading alternatives were developed assuming membranes as the basis of design.

Figure 2-5. DG upgrading system at San Mateo WWTP (California) using Unison's BioCNG system

Includes H_2S removal, moisture removal, compression, siloxane removal, and membrane separation.

The preliminary sizing for DG upgrading equipment is 400 scfm. Membrane separation systems can be supplied in 50, 100, 200, or 400 scfm capacities; given the current DG production at the WRP, the 400 scfm system will provide capacity for current DG flow variations with some capacity for growth.

Similar to conventional gas treatment systems that remove contaminants to improve engine performance, DG upgrading first involves gas conditioning to remove moisture, H_2S, and siloxanes from the raw DG and gas compression. The DG then goes through a membrane separation process to remove carbon dioxide (CO_2). Because the separation process is imperfect, the waste stream from the separation process is a methane (CH_4)-lean tail gas consisting primarily of CO_2 with up to 7 percent of the total DG CH_4 depending on the selected separation system. Tail gas is typically wasted using a flare or thermal oxidizer and may require a supplemental NG feed to help the tail gas combust. In some cases, tail gas is blended with NG to run engines or microturbines to avoid flare operation. Figure 2-6 shows a process flow diagram of a DG upgrading system.

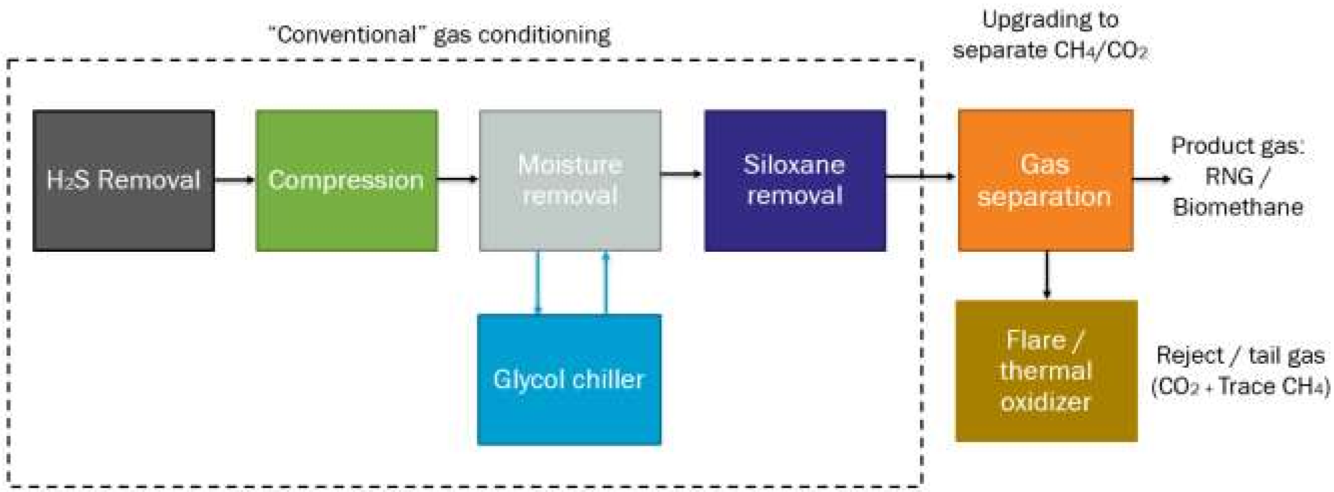


Figure 2-6. DG upgrading system schematic

2.3.2 Fuel Quality Standards for Upgraded DG

Pipeline fuel quality standards are higher than vehicle fueling standards, as shown in Table 2-6.

Table 2-6. Comparison of Typical DG Upgrading Pipeline Injection and Vehicle Fuel Quality Standards

Parameter	Vehicle Fueling	Pipeline Injection[c]
CH_4, percent by volume, min.	95	95
CO_2, percent by volume, max.	3.0	2.0
O_2, percent by volume, max.	0.1	0.2
Sum of CO_2, N_2, O_2 percent by volume, max.	5.0	
HHV, Btu/scfm, min.	960	950
Water, lb/million scfm, max.	7	6
H_2S, ppmv, max.	4	4
Mercaptan sulfur, ppmv, max.		120
Total sulfur, ppmv, max.	16	20 grains per ccf
p-Dichlorobenzene, ppmv, max.		9.5
Ethylbenzene, ppmv, max.		60

Table 2-6. Comparison of Typical DG Upgrading Pipeline Injection and Vehicle Fuel Quality Standards		
Parameter	Vehicle Fueling	Pipeline Injection[c]
Vinyl Chloride, ppmv, max.		3.3
Total measurable siloxanes, ppbv, max.	100	1,000
Toluene, ppmv, max.		2,400
Hydrogen, ppmv, max.		1,000
Mercury, ppmv, max.		0.00008
Total Ammonia, ppmv, max.	10	10
Temperature, degrees Fahrenheit, max.		120
Other volatile organic compounds, ppbv, max.	100	
Free of dust and gum, filtration to, micron, max.	0.3	0.2
Discharge pressure, psig	4,500	Depends on injection location. Usually ranges from 100 to 800 psig. Adjacent MERC connection is 55 psig.
Example facilities	Janesville, WI; San Mateo, CA; South Bend, IN	Point Loma, CA; Dubuque, IA

a. *Example pipeline injection quality standards from Northern Natural Gas Company. http://www.northernnaturalgas.com/Document%20Postings/Biomethane_Gas_Guidelines_rev080717.pdf*

b. *Example CNG vehicle fueling standards from Cummins Westport.*

c. *Some contaminants are not found in digester gas and may not require monitoring. MERC has indicated they would provide monitoring equipment for relevant gas contaminants.*

2.3.3 RIN Credits

Upgraded DG is eligible for incentives under the Renewable Fuel Standard 2 (RFS2), which is a United States Environmental Protection Agency (USEPA) program that requires transportation fuel to contain a minimum volume of renewable fuels. Qualified renewable fuel sources include biomass-based diesel, cellulosic biofuel, advanced biofuel, and total renewable fuel. RFS2 mandates that fuel refiners obtain renewable fuel credits (RINs) to meet a minimum percentage of renewable fuel production. To sell RINs, the DG facility must be certified as meeting USEPA requirements. Certified RINs are a tradable, environmental commodity with a monetary value. RIN revenue is available through either direct contract with an off-take entity, such as Trillium, or sale via a third-party broker. RIN credits are discussed further in Section 3.2.5.

2.3.4 Pipeline Tie-in

Sending biomethane to the existing Minnesota Energy Resources (MERC) pipeline eliminates the need for a local fleet to consume the upgraded DG and would allow for more flexibility with operations compared to on-site fueling alternatives because pipeline DG can be injected as it is produced rather than storing it. Figure 2-7 shows a pipeline injection "point of receipt" interconnection at the Point Loma WWTP that monitors gas quality, meters, and odorizes the renewable compressed NG prior to entering the pipeline.

Figure 2-7. Pipeline injection "point of receipt" at Point Loma WWTP

Monitors gas quality, prevents noncompliant gas from entering utility pipeline, and meters and odorizes RNG.

Figure 2-8 shows a potential location for a Minnesota Energy Resources (MERC) pipeline tie-in relative to existing NG pipelines. This pipeline operates at 55 psi and is a branch from a 275 psi pipeline a few miles away. Although the DG would be injected into this pipeline, it is likely that during winter months much of the actual DG will be drawn back out to the WRP for use in the boilers, but this does not reduce the revenue assumptions for the BCE.

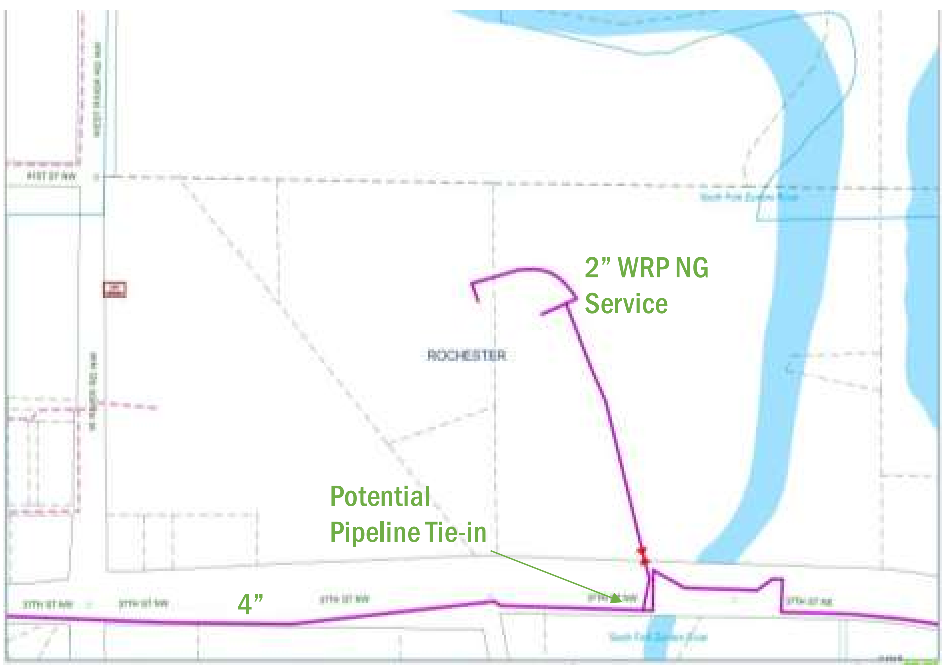


Figure 2-8. Potential location of existing NG pipeline for tie-in

The pipeline interconnection equipment that would be maintained by MERC requires a footprint up to 50 feet by 80 feet. Figure 2-9 shows a potential siting location for the DG upgrading equipment and pipeline injection monitoring equipment. It is important to note that 24/7 access to the pipeline injection monitoring equipment with a dedicated entrance is very important to the transmission districts and their ability to perform maintenance on these facilities. The WRP would need to provide MERC access to this equipment skid and this should be considered during design of any pipeline injection project.

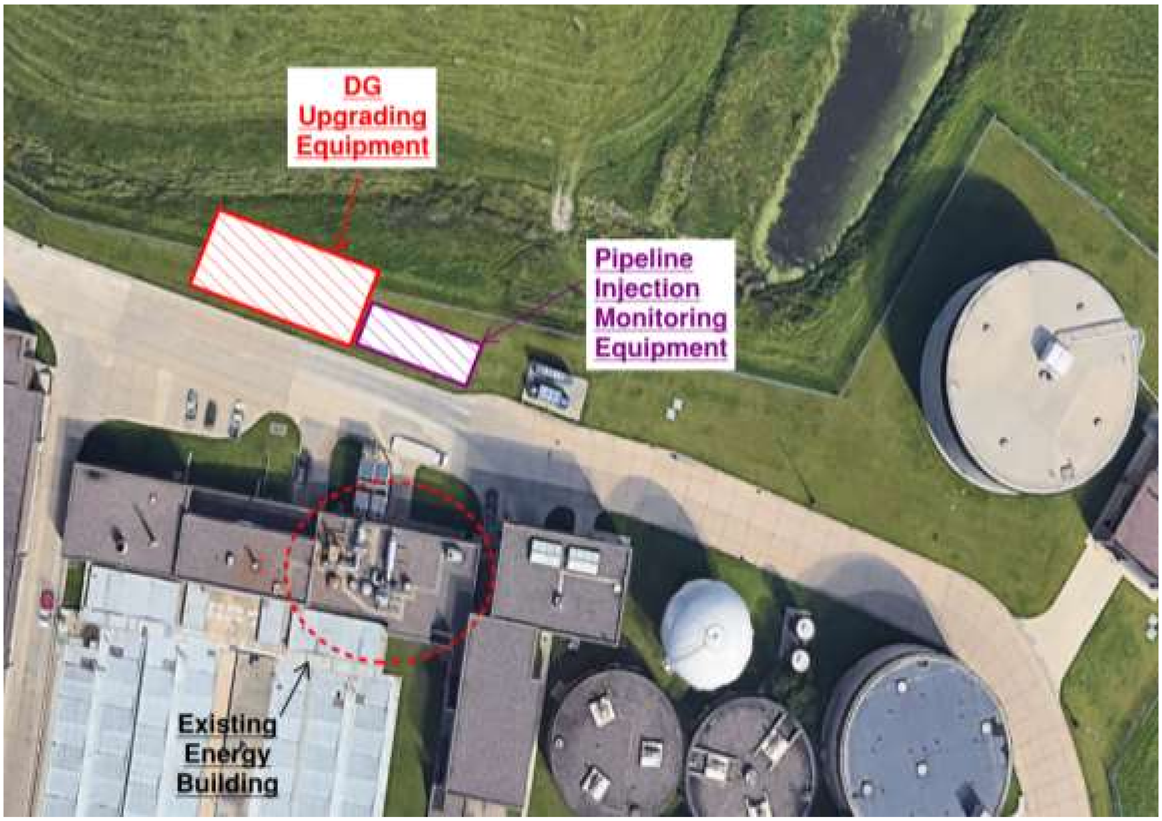


Figure 2-9. Potential location of existing NG pipeline for tie-in

Background Source: Google Earth

2.3.5 On-site Vehicle Fueling Considerations

On-site vehicle fueling requires additional equipment for compression, storage, and dispensing of CNG. High-pressure CNG compressors are required to boost the pressure of the gas up to approximately 4,500 psig. Figure 2-10 shows the high-pressure storage for on-site vehicle fueling and Figure 2-11 shows a CNG fueling dispenser installation. The approximate footprint for a fast-fill, on-site vehicle fueling station with four dispensers, three banks of high-pressure storage, and two high pressure compressors is approximately 50 feet by 110 feet. Figure 2-12 shows a potential site layout for the vehicle fueling alternative.

Figure 2-10. High-pressure CNG storage bank for on-site vehicle fueling

Figure 2-11. On-site vehicle fueling dispenser

Figure 2-12. On-site vehicle fueling site layout

Background Source: Google Earth

On-site fueling requires the City to find a committed, local partner that can use significant quantities of RNG fuel. Based on the quantity of DG the Rochester WRP produces, the vehicle fueling alternative would produce approximately 1,700 GGE per day of RNG. For RNG volumes of this magnitude, a large fleet of heavy-duty CNG vehicles is required to utilize the fuel. This typically means a municipality will upgrade their school bus or solid waste hauling vehicles to run on CNG to consume the product fuel. However, the City is converting buses to run as electric hybrid vehicles, eliminating a potential CNG fuel user. Therefore, the onsite vehicle fueling alternative would require another large end user partnership for this project to be feasible.

As an alternative to onsite vehicle fueling, vehicle fuel-quality biomethane may be transported to an offsite fueling facility via a tube trailer. Sometimes referred to as a 'virtual pipeline', this option eliminates the need for onsite storage but still requires a committed local partner.

2.3.6 Third Party Scenarios

DG upgrading, and pipeline injection systems are sometimes owned and/or operated by third-party entities, as illustrated in the following examples:

- The Point Loma WWTP in San Diego, California, currently upgrades its DG to biomethane or renewable pipeline NG. The WWTP's gas is sold to BioFuels Energy, LLC. This private entity operates the biomethane gas purification and injects the upgraded DG into the pipeline for use.

- The Dubuque WWTP (Iowa) constructed a 600 kW microturbine CHP system in 2014, along with a significant co-digestion program to maximize DG production in their digesters. Subsequently, they were approached by a third-party developer that offered the city a contractor at risk contract for 15 years with an option for another 5 years. The third party has rights to all DG and accepts the gas downstream of the gas conditioning (H_2S and siloxane removal) system. The DG is further compressed and upgraded with a pressure swing adsorption system. The third-party provider offered the city a percentage of gross revenue from RINs and gas sales, a lease and energy payments for their equipment site, and pipeline NG to replace their DG in the cogeneration system. Under RIN pricing conditions at the time of contracting, the city anticipated revenue of $180,000 per year for this system with no upfront capital or O&M costs to the city.

Contractual agreements with third-party entities can reduce the financial risk of the municipality, although the developer's profit may decrease the financial upside for the municipality. These third-party scenarios were not specifically included in the alternatives analysis but may be a feasible option for the City to consider if an RNG project is selected.

Section 3: Alternatives Comparison and Evaluation

This section presents a capital cost estimate, O&M costs, and NPV analysis for the DG utilization alternatives. A secondary alternative evaluation in Section 3.4 considers whether the capital and operating costs associated with adding siloxane treatment is likely to be justified by O&M savings.

3.1 Capital Cost Estimate

Conceptual capital cost estimates, including the individual component costs, were developed for all alternatives and are presented in Table 3-1. The capital costs are based on Class 5 conceptual cost estimates per the Association for the Advancement of Cost Engineering International (AACEI), which carry a level of accuracy of -30 to +100 percent. Major equipment costs were based on vendor budgetary estimates and comparable recent projects.

The capital costs in Table 3-1 reflect equipment sized for current conditions. DG upgrading costs assume a fully packaged system including H_2S removal, moisture removal and compression, siloxane removal, and gas separation. Since the WRP has low levels of H_2S and an existing moisture removal system, a custom unit may be engineered to lower capital costs and could be evaluated during design.

Table 3-1. Estimated Capital Costs for DG Utilization Alternatives

Cost Component	Status Quo Engines (2 at 1 MW)	Status Quo Engines (1 at 1 MW)	Microturbines with Gas Conditioning (5 at 200 kW)	Pipeline Injection (400 scfm)	Onsite Vehicle Fueling (400 scfm)
Engine replacement	$6.4M[a]	$2.5M[f]	-	-	-
Microturbines	-	-	$5.0M	-	-
Siloxane removal and compression	$0.5M[a]	$0.5M[a]	$0.8M	-	-
Gas upgrading	-	-	-	$6.5M	$6.5M
Pipeline and injection equipment				$2.0M [c]	
Vehicle fuel storage and fueling[b]	-	-	-		$6.5M
Engineering and administration[d]	$1.4M	$0.6M	$1.2M	$1.7M	$2.6M
Total Initial Project Cost for BCE	**$8.2M**	**$3.6M**	**$6.9M**	**$10.2M**	**$15.6M**
Potential project cost range for Class V estimate (-30 to +100%)	$6M–$16M	$2.5M–$7M	$5M–$14M	$7M–$20M	$11M–$31M
Future equipment replacement costs[e]	$0.5M	$0.5M	$0.5M	$1.0M	$1.0M

a. NPV assumes 2027 replacement expenditure for both engine generators.

b. Cost of fleet conversions from diesel to CNG not included. Storage and fueling costs depend on quantity of storage and number of dispensers desired. Assumed 4 fueling dispensers, two high pressure compressors and approximately 3 banks of high-pressure storage (minimum one day RNG storage).

c. Based on pipeline tie in location presented in this TM.

d. Assumed to be 20 percent of total construction cost.

e. Mechanical equipment replacement after 15 years of installation, including pumps compressors, etc.

f. NPV assumes 2027 replacement expenditure for one engine generator.

Because the engine generator replacements would be installed in 2027, the NPV analysis assumes a prorated engine salvage value at year 20 based on the following equation:

$$Salvage\ value = \frac{Number\ of\ useful\ years\ remaining}{Expected\ engine\ lifetime} * Capital\ cost$$

3.2 O&M Costs

Natural gas, CHP maintenance, electrical savings, and upgraded DG revenue cost assumptions are discussed in this section for the DG utilization alternatives.

3.2.1 NG for Heating and Boiler

For the status quo alternative, NG costs are expected to remain similar to current levels. Microturbines do not produce sufficient heat during summer months; therefore, supplemental NG would need to be purchased.

Under current conditions, DG is used in the boilers and engines to produce approximately 80 percent of the heat demand on an annual average basis. DG upgrading alternatives will divert DG away from the boilers and engines, and will require significant NG purchases for boiler fuel to ensure plant heat demands are met. Table 3-2 summarizes the assumptions for determining the NG costs for heating at the WRP.

Table 3-2. Natural Gas and Boiler Operating Cost Assumptions

Criterion	Value
Natural gas purchase price, $/therm	0.76
Thermal efficiency boiler, %	82

3.2.2 Cogeneration: Operating Costs

The O&M costs for the cogeneration alternatives are based on plant historical costs, industry experience, and vendor data. The Rochester WRP cogeneration costs include routine maintenance, such as oil changes and filter replacements, labor, and major events, such as top- and bottom-end overhauls. The gas treatment O&M costs include siloxane removal media replacement and associated labor following the new engine installations in 2027.

The O&M costs for the cogeneration alternatives are shown in Table 3-3. Note that the cogeneration and gas treatment operating costs are expressed on a per kW-hour ($/kWh) basis to reflect the run time and wear on the system. These should not be confused with the electrical savings described in the section below. Expressing O&M costs on a per kilowatt-hour (kWh) basis can be misleading because most O&M costs scale to operating hours more than kWh. If engine loading is low, O&M costs per kWh will be higher because fewer kWh are generated. As an example, if there was sufficient DG to run the Waukesha units at 900 kW and the annual maintenance costs stayed roughly the same, the O&M cost would fall from $0.028/kWh to $0.019/kWh.

Table 3-3. Internal Combustion Engine and Gas Treatment Operating Cost Assumptions

Criterion	Engines	Microturbines
Existing engine-generator O&M, $/kWh [a]	0.028	N/A
Replacement/new cogeneration O&M, $/kWh [b]	0.024	0.018
Blower and chiller power, percent of produced power [b]	6%	8%
Electrical efficiency new cogeneration, %	39	31
Thermal efficiency new cogeneration, %	36	21
Electrical efficiency existing cogeneration, %	28	N/A
Thermal efficiency existing cogeneration, %	39 (45 with siloxane removal)	N/A
Equipment uptime, % [d]	95	95
Gas treatment maintenance, $/yr [c]	29,000	34,000
Labor: cogeneration (FTE) [e]	0	0

a. *Provided by City staff based on historical costs.*

b. *Assuming future siloxane removal and increased engine loading reduces maintenance costs by roughly 25%.*

c. *For siloxane removal media replacement, shipping, labor and disposal. Note that the Unison Solutions estimate for media changeout costs were based on a DG flow rate of 500 scfm, but the average flow condition is 272 scfm. These costs have been scaled accordingly. Microturbine costs higher to account for additional siloxane sampling and potentially more frequent replacement interval.*

d. *Equipment uptime not 100% despite having a standby unit since siloxane media changeout will shutoff cogeneration operation. NPV analysis assumes cogeneration systems run for 7 months of the year and boilers run for 5 months of the year.*

e. *Included in O&M cost, per City staff.*

f. *Assuming average FTE salary, including fringe, of $70,000 annually.*

3.2.3 Cogeneration: Electrical Savings

To forecast electrical savings from DG cogeneration systems, the impact of engine downtime on demand savings must be considered. At a minimum, engine downtime will include oil changes every 1,000 to 2,000 hours, ideally scheduled to coincide with spark plug and gas treatment system media changes (if needed) to maximize engine availability. Microturbine downtime will include air filter and igniter replacement every 8,000 hours. The net result of this downtime is that cogeneration system electrical savings do offset demand-based charges (dollars per kW) in many months.

Electrical savings for alternatives that included CHP were calculated using the current WRP rates, which were provided by City staff at 6 cents per kWh usage. This evaluation only assumes usage charges are reduced for cogeneration options; actual savings may be greater if the City is able to operate cogeneration systems on a ‘perfect month’ basis without shutdown to also achieve $20 per kW for peak 15-minute demand savings.

As noted in Section 1.3.1, the WRP receives a credit of $4160 per month for based on their ability to support the local electrical grid with power production during curtailment periods. If the WRP chooses to pursue a pipeline injection project, additional analysis will be required to determine if it is economically advantageous to maintain natural-gas fueled cogeneration. If natural gas prices remain low, this cogeneration might be advantageous for both the curtailment credit and digester heating benefits.

Cogeneration availability also affects the electrical consumption savings based on generated kWh. This BCE assumes that the cogeneration availability is 95 percent (8,332 hours per year). This assumption is higher than a conventional assumption of 90 percent because a standby unit is provided for all options.

Electrical rates were assumed to increase at an annual rate of 2 percent.

3.2.4 DG Upgrading: Operating Costs

The O&M costs for DG upgrading for pipeline injection or on-site fueling are summarized in Table 3-4. The labor for on-site vehicle fueling is estimated to be higher than that for pipeline injection because additional coordination is required with the fleet to be fueled. Operating costs assume a 55 psig pipeline pressure and 4,000 psig for RNG.

Some heat recovery would be available from the compressor outlet, but the quantity is only on the order of 100,000-200,000 Btu/hr if the heat is added to the low temperature loop. This quantity of heat could be used to supplement the HVAC system, but would contribute less than 10% of the digester heat demand.

Table 3-4. DG Upgrading Operating Cost Assumptions

Criterion	Value
Gas upgrading maintenance ($/scfm-yr) [a]	450
Gas upgrading electrical consumption (kWh/scfm)	0.0071
Vehicle fueling maintenance ($/cfm-yr)	300
Feed-in tariff ($/therm) [b]	0.10
RIN Quality Assurance Program verification fees ($/yr)	50,000
Fuel recovery [c]	94%
DG upgrading availability	95%
Compressor power to pipeline (kW)	7.6
Compressor power for vehicle fuel (kW)	143
Average FTE salary, including fringe, $/yr	70,000
Labor: gas upgrading for pipeline injection (FTE)	0.5
Labor: gas upgrading and onsite vehicle fueling (FTE)	1.0

a. *Based on 2% of equipment capital cost per manufacturer.*

b. *The fee that the NG pipeline operator charges to accept the incoming upgraded DG.* ***To be confirmed by MERC.***

c. *The percentage of DG processed by the upgrading system that is not lost in the flared tail gas.*

3.2.5 DG Upgrading: Revenue

DG upgrading revenue varies based on the type of system:

- **Pipeline injection:** Municipalities injecting RNG into the pipeline typically pay a tariff to the NG utility who owns the pipeline for transporting the RNG to the end user. The municipality would then contract with a CNG fueling station or other fleet entity to purchase the RNG that has been injected into the pipeline for use in vehicles. NG revenue was estimated to be $0.40 per therm, which is approximately half of the price the Rochester WRP pays for NG and comparable to a wholesale price that CNG fueling stations pay for natural gas.

- **On-site fueling:** Other municipalities have negotiated long-term contracts with partner fleets based on a small discount over commercial CNG costs. Vehicle fuel revenue was estimated to be $2 per GGE based on recent CNG price data for the City, assuming the City would fuel its own fleet.

In addition to these revenue streams, RIN revenue can be realized under either of these scenarios. RINs are tradable credits, so their price fluctuates over time (shown in Figure 3-1). RIN values are subject to regulatory changes, but are statutorily mandated, so congressional action would be required to make major changes in the program. RIN pricing has fallen in 2019, in part due to an increase in waivers issued by the EPA to refineries that are required to purchase the RINs.

Wastewater-derived DG is eligible for D3 (cellulosic) and D5 RINs (advanced biofuels), with D3 RINs being the more valuable of the two. Because the USEPA is currently maintaining that high-strength waste (HSW) (fats, oils, grease, food waste, etc.) is not sufficiently cellulosic, WWTPs that import any feedstocks for co-digestion are only eligible for D5 RINs, currently valued at 10 to 20 percent of the value of a D3 RIN. Because the WRP does not currently import co-digestion feedstocks, 100 percent of the RINs produced for the pipeline injection and vehicle fueling alternatives would be eligible as D3 cellulosic RINs under the RFS2 program. However, if the WRP starts co-digesting HSW, the RIN revenue for the pipeline injection and vehicle fueling alternatives will be significantly reduced because the RINs would be classified as D5. Note that the EPA regulations for the classification of RINs produced from co-mingled feedstocks are subject to change as there are multiple groups requesting a methodology to quantify the RNG produced from D3 and D5 RINs separately.

Figure 3-1. Two-year D3 and D5 RIN trading price variability

(Source: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information)

Table 3-5 summarizes the revenue assumptions used for the DG upgrading NPV calculations. The long-term RIN value shown in Table 3-5 and used for the BCE is roughly 85 percent of the current market value for RINs in order to reflect costs associated with using a third-party broker to sell the credits.

Table 3-5. DG Upgrading Revenue Assumptions	
Criterion	**Value**
Pipeline injection NG sale ($/therm)	0.40
Vehicle fuel sale ($/GGE)[a]	2.00
Long-term D3 RIN forecast ($/RIN)[b]	1.60
Long-term D5 RIN forecast ($/RIN)[b]	0.45
Effective RIN recovery (%)[c]	85

a. Gallon of gasoline equivalent (GGE) = 114,000 Btu LHV. Based on CNG prices in Rochester as of March 2019.

b. RIN = 77,000 Btu LHV as defined by the USEPA.

c. Actual RIN revenue decreased to account for third party verification review costs and broker fees.

3.3 NPV Analysis

The NPV analysis includes the economic analysis assumptions summarized in previous sections and Table 3-6. As a conservative measure, no funding or grants are included in the NPV analysis. RINs are, however, included in the NPV analysis because they are not competitive to obtain. For the baseline NPV analysis, the electrical and NG utility costs are assumed to increase at the escalation rate identified in Table 3-6.

Table 3-6. NPV Assumptions	
Component	**NPV Assumption**
NPV term, years	20
Discount rate, annual percentage	3.0%
Inflation rate, annual percentage	2.0%
Real discount rate, annual percentage	1.0%
Utilities escalation rate, annual percentage	2.0%

The NPV results are based upon several assumptions and variables outlined in this TM and the data available at the time of the analysis. Actual NPV increases over the baseline alternative may vary if any of the assumptions or variables differ from what was assumed in the analysis.

Table 3-7 shows the NPV results and Table 3-8 summarizes the O&M costs on an annual basis for each alternative. Note that positive values reflect costs, while negative values reflect savings. Table 3-8 shows the baseline O&M costs broken down into subcategory.

Table 3 7. DG Utilization Alternatives 20-year NPV Results							
Cost Component	Status Quo Engines (2 at 1 MW)	Status Quo Engines[c] (1 at 1 MW)	Microturbines with Gas Conditioning (5 at 200 kW)	Pipeline Injection D3 RIN No HSW	Pipeline Injection D5 RIN With HSW	On-site Vehicle Fueling D3 RIN No HSW	On-site Vehicle Fueling D5 RIN With HSW
Initial Capital NPV	7.5 M[a]	3.5 M[a]	6.9 M	10.2 M	10.2 M	15.6 M	15.6 M
Future Capital NPV [a,b]	0.4 M	0.4 M	0.7 M	1.4 M	1.7 M	1.5 M	1.7 M
20-year NPV of O&M[d]	(2.9 M)	(2.6 M)[c]	(1.0 M)	(15.3 M)	4.2 M	(32.6 M)	(12.9 M)
20-year Salvage Value	(2.3M)	(1.0 M)	0	0	0	0	0
20-year NPV	2.8 M	0.2 M	6.6 M	(3.7 M)	16.1 M	(15.5 M)	4.4 M

a. *NPV of 2027 capital costs.*

b. *Future mechanical component replacements at 15 years.*

c. *One replacement engine, second existing engine remains for stand-by. Electrical savings for single new engine assumed to be 90% of dual new engine system due to lower efficiency and availability of the stand-by.*

d. *Net benefits (savings minus operating costs)*

Table 3-8. Annual O&M and Benefits Cost Breakdown							
Cost Component	Status Quo Engines[a] (2 at 1 MW)	Status Quo Engines[a] (1 at 1 MW)	Microturbines with Gas Conditioning (5 at 200 kW)	Pipeline Injection D3 RIN No HSW	Pipeline Injection D5 RIN With HSW	On-site Vehicle Fueling D3 RIN No HSW	On-site Vehicle Fueling D5 RIN With HSW
Total O&M Cost	145K	145K	196K	829K	829K	902K	902K
Equipment O&M	105K	105K	75K	122K	122K	204K	204K
Siloxane removal [c]	29K	29K	34K	0	0	0	0
Parasitic electrical	0	0	0	118K	118K	153K	153K
NG	10K	10K	87K	425K	425K	425K	425K
Additional staffing	0[b]	0[b]	0[b]	35K	35K	70K	70K
Gas transmission	0	0	0	79K	79K	0	0
RIN QAP[d]	0	0	0	50K	50K	50K	50K
Total Benefits	(320K)	(300K)	(254K)	(1,669K)	(598K)	(2,690K)	(1,610K)
Electrical savings from power generation	(270K)	(250K)	(204K)	0	0	0	0

Table 3-8. Annual O&M and Benefits Cost Breakdown							
Cost Component	Status Quo Engines[a] (2 at 1 MW)	Status Quo Engines[a] (1 at 1 MW)	Microturbines with Gas Conditioning (5 at 200 kW)	Pipeline Injection D3 RIN No HSW	Pipeline Injection D5 RIN With HSW	On-site Vehicle Fueling D3 RIN No HSW	On-site Vehicle Fueling D5 RIN With HSW
Curtailment credit	(50K)	(50K)	(50K)	0	0	0	0
CNG sale	0	0	0	(211K)	(211K)	(1,233K)	(1,233K)
RINs sale	0	0	0	(1,458K)	(378K)	(1,458K)	(378K)
Net Annual Costs	(175K)	(155K)	(58K)	(840K)	231K	(1,788K)	(789K)

a. *Reflects costs and electrical savings after engine replacement for Alternative 1*

b. *CHP staffing is included in O&M cost.*

c. *Siloxane removal costs for DG upgrading alternatives included in O&M.*

d. *RIN quality assurance plan administration to certify RINs for sale*

This NPV model assumes current DG production and D3 RIN values for 20 years at a reduced value ($1.60/RIN) in comparison to the current market value ($1.90/RIN). Some factors suggest that RIN pricing will remain high, especially for D3 cellulosic RINs. Actual cellulosic production is currently well below the statutory target obligated volumes because planned large-scale cellulosic ethanol production has not been successful. Also, the RFS2 legislation that created RINs has political support across political parties.

The NPV analysis in Table 3-8 includes DG upgrading alternatives using D5 RIN values to gauge how a co-digestion program would impact RIN revenue for the RNG alternatives. Under the current USEPA RIN interpretation, the addition of HSW and the lower D5 RIN value significantly undermines the financial viability of the DG upgrading alternatives.

In comparing all listed alternatives, the most favorable calculated NPV is where all DG is used for on-site RNG fueling. Sending all DG to produce a renewable vehicle fuel offers an economic benefit because the D3 RIN value and commodity value of fuel are both recoverable. However, there are hurdles in implementing this alternative, including the need to identify a fleet fueling partner. The pipeline injection alternative has smaller implementation barriers but appears to be less economically favorable under the somewhat conservative assumptions for sale value. As mentioned previously, pipeline injection can serve as an indirect pathway to a CNG fleet partner located in Minnesota or out of state.

Several of the gas upgrading systems on the market allow provisions for including a separate gas outlet prior to separating CO_2 from the CH_4 stream; this provides the City with flexibility to route conditioned gas from the gas upgrading system to the engines or boilers if pipeline injection incentives are no longer in place. This conditioned gas would also meet the treatment requirements upstream of the engines if a CO catalyst is installed on the engine exhaust.

Of the cogeneration alternatives, engines appear to have a favorable NPV in comparison to microturbines due to the higher electrical and thermal efficiencies of the technology. While the initial capital expenditures to replace the engine generators are higher, the increased electricity and heat production reduces annual power and NG bills.

3.4 Siloxane Removal NPV

As mentioned in Section 2.1.3, removing siloxanes upstream of the engine generators may reduce engine O&M and increase the heat recovery from the exhaust. If siloxane removal is not installed in the near term it will almost certainly be required when the engine generators are replaced to meet the engine manufacturer's fuel quality standards. An NPV analysis was conducted to determine whether installing siloxane removal in the near term is likely to be beneficial relative to future siloxane treatment installed with an engine generator replacement. The results of this NPV are based on a 7-year analysis (2020 to 2026). Operating cost assumptions used in this analysis are presented in Table 3-9.

Table 3-9. Engine Generator and Siloxane Treatment Operating Cost Assumptions

Criterion	Without Siloxane Removal	With Siloxane Removal
Engine-generator O&M, $/kWh [a]	0.028	0.024
Thermal efficiency, %	39[d]	45
Electrical efficiency - existing cogeneration, %	28	28
Gas treatment maintenance, $/yr [c]	0	29,000

a. *Provided by City staff based on historical costs.*

b. *Assuming siloxane removal reduces maintenance costs by 25%.*

c. *For siloxane removal media replacement, shipping, labor and disposal. Note that the Unison Solutions estimate for media changeout costs were based on a DG flow rate of 500 scfm, but the average flow condition is 272 scfm. These costs have been scaled accordingly.*

d. *Includes assumed reduction in rated thermal efficiency due to silica deposits in exhaust heat recovery*

This siloxane NPV analysis assumes a $450,000 construction cost for two carbon media vessels. NG costs were assumed to decrease for the siloxane removal alternatives if heat recovery units are cleaned and no longer exposed to additional silica.

Based on the O&M information presented in Table 2-2, the primary impact of siloxane combustion is damage to pistons, with relatively minor impacts to routine oil and spark plug maintenance. Given this experience, a 10 to 15 percent reduction in engine O&M costs was estimated.

A sensitivity analysis was performed on media life since the Unison Solutions estimate for annual media replacement costs were based on very limited DG sampling and may not be representative of the typical gas profile. In addition, previous gas sampling did not include VOCs, which can compete with siloxanes for carbon capacity. In this sensitivity analysis, a range of siloxane media O&M costs varying from -20 to +40 percent were considered.

Table 3-10 presents the results of the siloxane removal evaluation. Because it is likely that the siloxane removal equipment could have continued use with a future biogas utilization alternative (new engines or biogas upgrading), NPV was considered both with and without salvage. The "Status Quo Engine" scenario has the lowest NPV, indicating that there is not a significant financial benefit to installing siloxane removal before it is needed for future gas utilization alternatives.

Table 3-10. Siloxane Removal Annual O&M Costs and Net Present Value				
Cost Component	Status Quo Engines	Status Quo Engines with Siloxane Removal	Status Quo Engines with Siloxane Removal (-20% Media Cost)	Status Quo Engines with Siloxane Removal (+40%Media Cost)
Engine O&M [a]	105K	90K	90K	90K
NG	10K	0	0	0
Siloxane media replacement	0	29K	23K	41K
Additional staffing [b]	0	0	0	0
Total O&M	115K	119K	114K	131K
7-year NPV of O&M	788K	812K	772K	891K
7-year NPV without salvage	788K	1,401K	1,312K	1,431K
7-year NPV with salvage[c]	788K	1,096K	772K	1,175K

a. *Assuming costs prior to engine replacement.*
b. *Assumes staffing is included in O&M cost.*
c. *Salvage value assumes 60% of asset value remaining after 10 years*
d. *Peak shaving curtailment credit and electrical savings assumed the same all alternatives.*

Section 4: Summary and Recommendations

The results of the DG utilization BCE indicate that beneficially using DG via pipeline injection with RIN contracting can provide economic benefit over the current DG operating scenario if RIN pricing remains at current (or better) levels over the life of the project. These results also assume the WRP will not co-digest HSW; a co-digestion program would significantly reduce RIN revenues based on the EPA's current interpretation of RIN classification and suggest that the status quo operation is more economically viable. However, the pipeline injection alternative has additional advantages for the Rochester WRP relative to other DG utilization alternatives:

- Fewer mechanical components and less complex control systems
- Flexibility for future operations if RIN values decrease (i.e., there is still an option to send conditioned DG to the engines)
- Less mechanical wear associated with system stops and starts
- Potential for external investment partners

Other alternatives are less attractive for various reasons:

- **On-site vehicle fueling:** The vehicle fuel alternative produces 1,700 GGEs per day, requiring a large fleet with CNG-fueled vehicles, such as municipal buses or garbage trucks, to utilize this fuel. In addition, the trucks would require access to the site for fueling, which may be disruptive to the adjacent neighborhood.
- **Microturbines**: The microturbine alternative has a lower capital investment in comparison to engines, but the reduced electrical and thermal efficiencies result in less long-term power and NG savings. In addition, there are only two small manufacturers that can provide equipment which can be a risk in securing long-term parts and service.

The pipeline DG project proposed in this TM has economic benefit over the cogeneration alternatives if RIN values continue to maintain current values. Therefore, incremental steps could be pursued to investigate this option, including:

- MERC has indicated that they are unwilling to construction a pipeline injection facility to serve the WRP. In order to pursue the pipeline injection approach, continuing dialog will be required to identify and address MERC's concerns about this arrangement.
- Visiting a facility that is doing pipeline injection such as Dubuque, Iowa.
- Discussing the business details of possible RIN arrangements with potential RIN off-take partners or developers such as Trillium, Chevron, or Clean Energy.
- Conducting additional gas sampling for major constituents, H_2S, VOCs and siloxanes to refine DG treatment costs. Prior to making a final decision, obtain three to four additional samples to confirm that there are no significant changes in the contaminant levels that would impact the O&M costs.
- Tracking CenterPoint Energy's recently announced plan to offer RNG to their customers who want to be more sustainable. The RNG would be billed at a premium price relative to regular natural gas billing. CenterPoint Energy's plan to purchase RNG was rejected by the Minnesota Commerce Department, but might be re-submitted with revisions to address various issues. It appears that CenterPoint plans to offer revenue comparable to RINs. (http://www.startribune.com/minnesota-utility-pursues-renewable-natural-gas-option/505604482/).

- Considering the feasibility of adding additional heat recovery and optimizing existing HVAC systems to reduce future NG costs if biogas is sold as vehicle fuel. These options could include increased use of effluent heat recovery or heat pumps, air to air HEXs for building heat, or solar thermal collectors.

If, after further investigation, a pipeline injection project is not chosen as a long-term biogas alternative, replacing the existing engine generators with newer, more-efficient units still achieves Rochester WRP's goals of producing renewable power and thermal energy.

Although siloxane removal is likely to be required with future biogas utilization alternatives (either the pipeline injection or engine-generator), installation of siloxane removal in the near term does not appear to be cost-justified based on estimated improvements in engine O&M and heat recovery.

Attachment A: Vendor Quotes

Biogas Upgrading System Vendor Quotes

UNISON SOLUTIONS

Leaders in Biogas Technology

BUDGET PROPOSAL
BIOGAS UPGRADING SYSTEM
SECTION 43 32 77

Date: 9/26/2018
Expires: 10/26/2018

Alison Nojima
Brown and Caldwell

Proposal Number: BC-117-2535.1
Project Name: Roseville Pleasant Grove WWTP

Unison Solutions, Inc. is pleased to provide this proposal for a Biogas Upgrading System for the Roseville Pleasant Grove WWTP Project. This proposal includes all of the CAD design services, technician labor, fabrication and materials to construct a Biogas Upgrading System.

Thank you for giving Unison Solutions the opportunity to provide you with the enclosed proposal. If you have questions or require additional information, please contact me at your convenience.

Sincerely,

Adam Klaas
Unison Solutions, Inc.
Phone: 563-585-0967
Cell: 563-542-3081

SPECIFICATION

- Section 43 32 77 – Biogas Upgrading System

EXCEPTIONS/CLARIFICATIONS TO SPECIFICATIONS

- 1.02: Ammonia Removal is not part of the specification or quoted system therefore outlet ammonia levels cannot be guaranteed.
- All anchor bolts will be supplied by installation contractor.
- 1.05/19: All foundation design is to be done by others.
- 2.02/11: Tail Gas After-Cooler is a finned plate type heat exchanger. The materials of construction are aluminum for both the fins and plates.
-

UNISON SOLUTIONS, INC. CERTIFICATIONS

- ASME Certification Number (U-Stamp) - 37,381
- ASME Certification Number (R-Stamp) - R7415
- UL Certification Number - 20110405-E255550

EQUIPMENT/SUB-SYSTEMS

HYDROGEN SULFIDE REMOVAL SYSTEM

- Hydrogen Sulfide Removal Media Vessels
- Work Platforms and Ladder
- Lead/Lag Piping and Valves
- Initial Charge of H_2S Removal Media

GAS COMPRESSION/MOISTURE REMOVAL SYSTEM

- Gas Compressor Inlet Moisture/Particulate Filter
- Pre-cooler
- Gas Compressors
- Oil/Gas Separators
- Oil Coolers
- Oil Particulate Filters
- Gas to Gas Heat Exchanger
- Gas to Glycol Heat Exchanger
- Moisture Separator
- Gas Recirculation
- Siloxane/VOC Removal Vessels
- Initial charge of Siloxane/VOC Removal Media
- Final Particulate Filter
- Skid Base

CO_2 REMOVAL SYSTEM

- Single Pass CO_2 Removal System
- Product Gas B200 Flow Meter with CH_4 Signal
- Tail Gas B200 Flow Meter with CH_4 Signal
- Product Gas Odorizer

GLYCOL CHILLER

- Glycol Chiller
- Initial fill of Propylene Glycol/Water Mixture

TAIL GAS COMPRESSION/AFTER-COOLER SYSTEM

- Buffer Tank
- Gas Compressor Packages
- Air to Gas After-Cooler
- Buffer Tank
- Gas Recirculation

NATURAL GAS BLENDING SYSTEM

- NG Electric Actuated Shut-off Valve
- NG Modulating Flow Valve
- Blended Gas B200 Flow Meter with CH_4 Signal
- Mounted on Compression/Moisture Removal System

CONTROL SYSTEM

- Gas Conditioning System Control Panel
- Transformer
- Wall Mounted VFDs

GAS ANALYSIS PANEL

- Gas Analyzer for CH_4, CO_2, O_2
- Calibration Gas with Regulators

SOUND ENCLOSURE

- Steel Exterior
- Ventilation Fan and Intake Louvers
- LEL and H_2S Monitor with Beacon Light
- Incandescent Light Fixtures

CAPSTONE TURBINE FUEL KIT COMPONENTS

- Ball Valves
- Pressure Reducing Valve
- Particulate Filter
- Pressure Gauge

DESIGN CONDITIONS

SITE INFORMATION

- Minimum Ambient Temperature	35°F
- Maximum Ambient Temperature	100°F
- Site Elevation	275' AMSL

SYSTEM REQUIREMENTS

- Minimum Gas Flow	50 scfm
- Maximum Gas Flow	400 scfm

INLET GAS CONDITIONS

- Minimum Inlet Gas Pressure	4"WC
- Maximum Inlet Gas Pressure	12"WC
- Minimum Inlet Gas Temperature	60°F
- Maximum Inlet Gas Temperature	105°F
- Methane (CH_4)	55-65%
- Carbon Dioxide (CO_2)	35-45%
- Nitrogen (N_2)	0-0.75%
- Oxygen (O_2)	0-500 ppmv
- Water Dew Point	60-98°F @ inlet pressure
- Hydrogen Sulfide (H_2S)	1,000 ppmv
- VOC/Siloxanes (L2, L3, L4, L5, D3, D4, D5, D6)	0-2,000 ppbv
- Ammonia	<10ppmv
- VOCs	0-5 ppmv

PRODUCT GAS CONDITIONS

- Discharge Gas Pressure	120 psig
- Discharge Gas Temperature	60-80°F
- Methane (CH_4)	95%
- Carbon Dioxide (CO_2)	3%
- Oxygen (O_2)	<0.1%
- Sum of Inerts (CO_2, N_2, O_2)	5%
- Higher Heating Value	960 Btu/scf
- Water	7#/mmscf
- Hydrogen Sulfide (H_2S)	4 ppmv
- Total Sulfur	16 ppmv
- Maximum Siloxane	<100 ppbv
- VOCs	<100 ppbv
- Particulate Removal	99% removal of >0.5 micron

TAIL GAS CONDITIONS

- Discharge Gas Pressure (min)	10 psig
- Discharge Gas Temperature	60-80°F
- Higher Heating Value (min)	300 Btu/scf

TAIL/NATURAL GAS BLEND CONDITIONS

- Discharge Gas Pressure (min)	80 psig
- Discharge Gas Temperature	70-120°F
- Higher Heating Value	600-875 Btu/scf
- Maximum Btu Content rate of change	10 Btu/scf/sec

SITE REQUIREMENTS

ELECTRICAL CLASSIFICATION

- NEC Class I, Division 1 Group D Areas
    - Hydrogen Sulfide Removal System
    - Gas Compression/Moisture Removal System
    - Siloxane/VOC Removal System
    - CO_2 Removal System
    - Tail Gas Compression/After-Cooler System
    - Buffer Tanks
    - Natural Gas Blending System
    - Sound Enclosure
- Unclassified Electrical Areas
    - Glycol Chiller
    - Gas Conditioning System Control Panel
    - Transformer
    - Wall Mounted VFDs
    - Gas Analyzer

EQUIPMENT MOUNTING

- Skid Mounted
    - Gas Compression/Moisture Removal System
    - Siloxane/VOC Removal System
    - CO_2 Removal System
    - Tail Gas Compression/After-Cooler System
    - Natural Gas Blending System
    - Sound Enclosure

- Standalone

  - Hydrogen Sulfide Removal System
  - Buffer Tanks
  - Glycol Chiller
  - Gas Conditioning System Control Panel
  - Transformer
  - Wall Mounted VFDs
  - Gas Analysis Panel

EQUIPMENT/SUB-SYSTEM DETAILS

HYDROGEN SULFIDE REMOVAL SYSTEM

- (2) Hydrogen Sulfide Removal Media Vessels

  - 10’Ø x 10’ straight side
  - Rated for 5psig pressure and 1psig vacuum
  - Materials of construction shall be 304L stainless steel
  - 150# ANSI B16.5 side inlet and outlet connections
  - Flanged and dished top head
  - Flanged and dished or flat bottom head
  - Vessels shall be free-standing
  - Vessels equipped with a 36” top manway
  - Vessels equipped with a 24” side manway
  - Internal supports and grating for media
  - Pressure/Vacuum relief valves included
  - Two top vents with stainless steel ball valves
  - Bottom manual condensate drain with stainless steel ball valves, manual drain bypass. Drains will be U-trap type drains.
  - Lead/Lag piping and valves for Hydrogen Sulfide Removal Vessels will be provided.
  - Block and Bleed isolation valves on inlet and outlet of each vessel

- Work Platform and Ladder

  - Work platform shall be welded carbon steel construction with satin black powder coat finish
  - Ladder shall be aluminum construction

- Initial Charge of H_2S Removal Media

  - The initial charge of Ferric Hydroxide H_2S Removal media for each Hydrogen Sulfide Removal Media Vessel will be provided.
  - H_2S Removal to be loaded into Hydrogen Sulfide Removal Vessels by INSTALLATION CONTRACTOR

GAS COMPRESSION/MOISTURE REMOVAL SYSTEM

- Gas Compressor Inlet Moisture/Particulate Filter

  - Mounted upstream of the Gas Compressor
  - 99% removal of 3micron and larger particulates and liquid droplets
  - Materials of construction shall be 304L stainless steel
  - 150# ANSI B16.5 side inlet and outlet connections
  - Cleanable polypropylene structured mesh element
  - Differential pressure gauge across the filter element
  - Sight glass for liquid level indication
  - Level switches above the condensate drain to warn of failure
  - Bottom drain with strainer, condensate pump, check valve, manual bypass and piping

- Pre-cooler

  - Within the heat exchanger the gas will be cooled to 50°F
  - Gas to Glycol fin/tube core
  - Materials of construction shall be 304L stainless steel tubes with aluminum fins inside a 304L stainless steel housing.
  - 150# ANSI B16.5 inlet and outlet connections

- Gas Compressor

  - Two Oil Flooded Twin Screw Compressors rated for 200scfm each
  - Direct drive 100Hp, 480V/3Ph/60Hz electric motors
  - Motor speeds will be controlled by a VFD
  - All gas and oil components other than the compressor head shall be constructed of stainless steel and/or aluminum.
  - Gas inlet and discharge flex connectors
  - Gas inlet and discharge isolation valves
  - Gas inlet check valve
  - Discharge pressure safety valve
  - Oil handling system will include an oil handling reservoir, coalescing filter, pressure safety valve, oil cooler, three-way thermal bypass valve and an oil particulate filter.
  - Initial fill of oil for the Gas Compressor systems will be provided

- Oil/Gas Separators

  - ASME Section VIII, Division 1 code stamped
  - Materials of construction shall be 304L stainless steel
  - ANSI B16.5 inlet and outlet connections
  - Discharge check valve

- Oil Coolers

  - Air to oil fin/tube core

- Materials of construction shall be aluminum fins and tubes
- Flange connections
- 480V/3Ph/60Hz EXP electric motor

- Oil Particulate Filters

  - Inline oil filter to remove particulate from oil stream
  - Replaceable elements
  - Materials of construction shall be 304L stainless steel

- Gas to Gas Heat Exchanger

  - Brazed plate
  - Materials of construction shall be 304L stainless steel body with nickel/chrome brazing
  - ANSI B16.5 inlet and outlet connections

- Gas to Glycol Heat Exchanger

  - Brazed plate
  - Materials of construction shall be 304L stainless steel body with nickel/chrome brazing
  - ANSI B16.5 inlet and outlet connections

- Moisture Separator

  - Uni-Flow Model
  - ASME Section VIII, Division 1 code stamped
  - Materials of construction shall be 304L stainless steel
  - ANSI B16.5 inlet and outlet connections
  - Centrifugal style with no element to be cleaned or changed
  - Integral level switched for drain control
  - Bottom drain with strainer, solenoid valve, check valve, manual bypass and piping

- Gas Recirculation

  - Backpressure regulator shall be provided to allow excess gas to flow from the discharge of the system back to the inlet of the Gas Compressor.

- Skid Bases

  - Welded carbon steel construction with satin black powder-coat finish
  - All components mounted, piped and wired on skid base
  - 24V and 120V electrical components wired to one of two junction boxes on edge of skid
  - INSTALLATION CONTRACTOR to provide conduit and wiring to 480V components

- Conduit shall be rigid aluminum
- Condensate drains piped to edge of the skid base. Drains to be routed to floor drain by INSTALLATION CONTRACTOR.

GLYCOL CHILLER

- Glycol Chiller

    - Sized for the process heat load
    - Suitable for outdoor installation
    - Refrigeration System
        - Two independent refrigeration circuits sized for 50% capacity each
        - Two compressors sized for 50% capacity each
            * 5 year compressor warranty
        - Chiller capacity: 25% to 100% of rated capacity
        - EC motor driven condenser fans
        - Aluminum micro-channel air cooled condensers
        - 316L stainless steel evaporators
        - R410a refrigerant. R-410a is an HFC refrigerant with 0 ODP
        - Refrigeration circuit has sealed core filter drier, liquid line solenoid valve, liquid line shut-off valve, and sight glass/moisture indicator
        - Electronic expansion valve, one per refrigeration circuit
        - Glycol Chiller shall be factory tested and shipped with complete refrigerant charge
    - Glycol Circulation
        - Dual glycol circulation pumps sized for 100% capacity
        - Stainless steel end suction centrifugal pumps
        - TEFC Pump Motors
        - Pump isolation valves on inlet and outlet
        - Pump discharge check valves
        - Glycol reservoir is a 304 stainless steel closed tank
        - Glycol piping is copper with anti-corrosion coating
        - Armaflex insulation
        - Glycol Chiller to utilize propylene glycol/water mix
        - Initial fill of Propylene glycol will be provided
    - Support Structure
        - G90 galvanized steel member frame
        - Powder-coated aluminum cover panels
        - All components mounted, piped and wired on skid
    - Glycol Chiller Control Panel
        - UL Type 4X
        - UL 508A Listed Industrial Control Panel
        - 316L Stainless Steel
        - 480V/3Ph/60Hz feed will be required
        - 480V disconnect
        - Microprocessor based controller with full text LCD display
        - 480VAC to 24VAC transformer

SILOXANE/VOC REMOVAL SYSTEM

- (3) Siloxane/VOC Removal Vessels

    - Three (3) 36”Ø x 8’ straight side Siloxane Removal Vessels
    - Materials of construction shall be 304L stainless steel
    - ANSI B16.5 inlet and outlet connections
    - ASME Section VIII Code Stamped
    - Flanged and dished top and bottom heads
    - Vessels shall be skid mounted with skirted bottoms
    - Elliptical access nozzle on top of each vessel
    - Internal septas for even gas distribution through media
    - Pressure relief valves included
    - Bottom manual condensate drain with stainless steel ball valves
    - Test/purge ports with ball valves on the inlet and outlet of each Siloxane Removal Media Vessel
    - Series piping with bypass around each vessel and valves between Vessels will be provided
    - Block and Bleed isolation valves on inlet and outlet of each vessel

- Work Platform and Ladder

    - Work Platform shall be welded carbon steel construction with satin black powder coat finish
    - Ladder shall be aluminum construction

- Initial charge of Siloxane/VOC Removal Media

    - The initial charge of media for each vessel will be provided.
    - The media shall be specifically engineered for removal of siloxanes, VOCs and similar contaminants from landfill and digester gas sources.
    - Siloxane media to be loaded into the Siloxane Removal Media Vessels by the INSTALLATION CONTRACTOR.

- Final Particulate Filter

    - Mounted downstream of the Siloxane Removal Vessels
    - 99% removal of .5 micron and larger particulate
    - Materials of construction shall be 304L stainless steel for filter housing and cartridge style element
    - 150# ANSI B16.5 side inlet and outlet connections

Single Pass CO_2 REMOVAL SYSTEM

- Single Pass CO_2 Removal System

    - Mounted downstream of the Siloxane/VOC Removal System

- Materials of construction shall be 304L stainless steel for filter housing and cartridge style membrane element
- Modulating valves for pressure control
- Tail Gas Line to the Flare (Flare supplied by others)
- Product gas flow meter
- Gas Odorizer
- Automated isolation valves on 3 membranes (inlet and product gas)

GAS ANALYSIS PANEL

- Type 4X Stainless Steel Enclosure
- CH_4 0-100% (NDIR)
- CO_2 0-5% (NDIR)
- O_2 0-25% (Electrochemical)
- Outputs: 4-20mA
- Back Pressure Regulator
- Zero and Span Solenoid Valves for Automatic Calibration
- Inlet Pressure Regulator
- Flowmeters with Needle Valve
- External Fittings for Zero, Span, and Sample Gas Connections
- Thermoelectric Condensate Removal System with Drain and H_2O Sensor
- Internal Sample Pump
- Calibration Gas & Regulators Supplied (One Year)

GAS COMPRESSION/MOISTURE REMOVAL SYSTEM

- Compressor Inlet Buffer Tank

    - Mounted upstream of the Gas Compressor Systems
    - Materials of construction shall be 304L stainless steel
    - ANSI B16.5 inlet and outlet connections
    - ASME Section VIII Code Stamped
    - Flanged and dished top and bottom heads
    - Vessels shall be skid mounted with skirted bottoms

- Gas Compressor Package

    - Two Rotary Vane Compressors sized for 150scfm each
    - Direct drive 40Hp, 480V/3Ph/60Hz electric motors
    - Motor speeds will be controlled by VFDs
    - Self-regulating servo control
    - Oil sumps
    - Safety relief valves
    - Oil sump temperature
    - Bushing temperature
    - Oil filters
    - Thermostatic valves
    - Integrated oil coolers

- Oil separators

- Air to Gas After-Cooler

  - Air to Gas plate/fin core
  - Materials of construction shall be aluminum plate and fins
  - Galvanized steel fan shroud
  - 480V/3Ph/60Hz EXP electric motor
  - Motor speed will be controlled by a VFD to control gas discharge temperature

- Gas Recirculation

  - Backpressure regulator shall be provided to allow excess gas to flow from the discharge of the system back to the inlet of the Gas Compressor.

NATURAL GAS BLENDING SYSTEM

- NG Electric Actuated Shut-off Valve
- NG Modulating Flow Valve
- Blended Gas B200 Flow Meter with CH_4 Signal
- Mounted on Compression/Moisture Removal System

- MIXED GAS BUFFER TANK

- Mounted upstream of the Gas Compressor Systems
- Materials of construction shall be 304L stainless steel
- ANSI B16.5 inlet and outlet connections
- ASME Section VIII Code Stamped
- Flanged and dished top and bottom heads
- Vessels shall be skid mounted with skirted bottoms

CONTROL SYSTEM

- Gas Conditioning System Control Panel

  - Enclosure
    - UL Type 12
    - UL 508A Listed Industrial Control Panel
    - Painted carbon steel
    - Outdoor Location
  - Thermal Management
    - Air Conditioner
  - Power Distribution
    - Fused Disconnect
    - 480V/3Ph/60Hz feed required
    - 35kA Short Circuit Current Rating
    - Over current and branch circuit protection via fuses

- 480VAC field wiring to terminate at the component or terminal strips inside control panel
- Surge Suppression
  - 480VAC Transient Voltage Surge Suppressor
  - 120VAC Surge Filter
- Motor Control (Wall Mounted VFDs)
  - (2) 100Hp rated 6 pulse VFDs for Compressor Motors
  - (2) 40Hp rated 6 pulse VFDs for Tail Gas Compressor Motors
  - (1) 2Hp rated 6 pulse VFD for Air to Gas After-Cooler
  - (2) 2Hp rated Motor Starter Overload for Oil Cooler Motors
  - (1) ½ Hp rated Motor Starter Overload for Condensate Pump
- Programmable Logic Controller
  - Allen Bradley
  - Compact Logix PLC and I/O
  - Native Allen Bradley Ethernet IP data network
  - Modbus TCP/IP communication card for Micro Turbine comms
- Human Machine Interface
  - Allen Bradley Panelview 6
  - TFT Color LCD Display
  - 12” diagonal
- Instrument wiring to terminate at terminal strips inside Control Panel

- Transformer
  - 3 kVA
  - 480VAC to 120VAC
  - NEMA 3R; Painted carbon steel

INSTRUMENTATION

- All instrumentation provided will be designed for gas service and rated for use in a NEC Class I, Division 1 Group D area.
- Hydrogen Sulfide Removal System Instrumentation
  - Inlet Pressure Transmitter
  - Inlet Temperature Gauge
- Gas Compression/Moisture Removal System Instrumentation
  - Level Switches at each Condensate Drain
  - Level Indicators at each Condensate Drain
  - Temperature Transmitter at each Temperature Change Point
  - Temperature Transmitter to Monitor Glycol Temperature
  - Bi-metal Thermometers at each Temperature Change Point
  - Gas Compressor Discharge Pressure Transmitters
  - Delivery Pressure Transmitter
- CO_2 Removal System Instrumentation
  - BioCNG System Delivery Pressure Transmitter
  - Gas Analyzer
  - Product Gas Flow Meter
- Tail Gas Compression System Instrumentation
  - Compressor Inlet Pressure Transmitter

- Delivery Pressure Transmitter
- Delivery Temperature Transmitter
- Natural Gas Blending System
  - B200 Flow Meter

PIPING

- Pipe upstream of H_2S Removal will be SA-312 TP316/316L Weld Pipe, minimum Schedule 10S. Threaded pipe shall be minimum Schedule 40S.
- Pipe will be SA-312 TP304/304L Weld Pipe, minimum Schedule 10S. Threaded pipe shall be minimum Schedule 40S.
- Flange connections will be ANSI B16.5, SA-182 F304/304L Class 150.
- Pipe welding will follow ASME B31.3 Process Piping. Welded pipe will be visually inspected and pressure tested.
- Gaskets will be 1/16" nitrile bound non-asbestos ring gaskets.

VALVES

- Ball Valves
  - Stainless steel with RTFE seat.
  - Valves will be full port
  - Below 2": 3 piece
  - 2" and above flanged
  - 316 stainless steel body, ball, and trim
- Butterfly Valves
  - Low Pressure:
    - Lug style iron body
    - 316 stainless steel disc and stem
    - PTFE packing
    - Viton seat
    - Stainless steel handles
  - Medium Pressure:
    - Lug style stainless steel body
    - 316 stainless steel disc and stem
    - High performance type double offset
    - PTFE seat
    - Stainless steel handles
- Check Valves
  - Will be one of 2 styles; ball or dual-door.
    - Ball check valves shall be stainless steel with RTFE ball.
    - Dual-door check valves shall be wafer style body, material shall be aluminum and/or stainless steel with an FKM seat.
- Globe Valves
  - Stainless steel with PTFE packing

FASTENERS

- Fasteners shall be ASTM F593 304 Stainless Steel

SOUND ENCLOSURE

- All electrical inside the enclosure is rated Class I Division 1
- Steel exterior with multiple color options for site esthetics
- 1/2" plywood construction over steel studs
- Insulated walls and ceiling
- Interior 5/8" green board (mildew resistant drywall)
- Lighted interior with two EXP incandescent light fixtures
- LEL inside enclosure for gas detection and warning
- Ventilation fan and intake louver to prevent over heating inside enclosure
- Double steel entry doors

Note: Customer will be required to power the ventilation fan and lights

GENERAL INCLUSIONS

- Radiographic testing of welds in accordance with RT3 markings per ASME Section VII on all vessels.
- California PE stamped seismic calculations for all vessels and anchoring.

SPARE PARTS

- Per section 2.18 of spec Section 43 22 77.

SUBMITTALS

- Quantity: (3) copies of 3 ring binders and (1) electronic CD copy
- Shop Drawings and Product Data will be provided in sufficient detail to confirm compliance with the requirements for the project. Shop Drawings and Product Data will be provided in a complete submittal package.
- Shop Drawings
    - Installation drawings and specifically prepared technical data, including design capacities will be provided.
    - Specifically prepared wiring diagrams unless standard wiring diagrams are submitted with product data will be provided.
    - Written description of operation will be provided.
- Product Data
    - Catalog cuts and product specifications for each product specified will be provided.
    - Standard wiring diagrams unless wiring diagrams are specifically prepared and submitted with Shop Drawings will be provided.

FACTORY TESTING

- The System will be tested on ambient air at Unison's facility prior to shipment.
- The CUSTOMER is allowed to witness the testing and Unison will inform the customer (2) weeks prior to anticipated testing date so customer can make travel arrangements.

OPERATION & MAINTENANCE MANUALS

- Quantity: (3) copies of 3 ring binders and (1) electronic CD copy

- After shipment the Gas Conditioning System will be provided with a specifically prepared Operation & Maintenance Manuals. The information provided includes a system overview, operator interface, start-up/shut down procedures, communications, alarms procedures, maintenance overview, mechanical component spec sheets and electrical component spec sheets.

MANUFACTURER'S FIELD SERVICES

INSPECTION, TESTING, START-UP, AND TRAINING SERVICES

- Includes twenty-two (22) non-consecutive, 8-hour days, six trips for one Unison Technician onsite with travel and expenses included.

GAS TESTING AND ANALYSIS SERVICES

- Total of 18 gas testing kits
- Lab Analysis cost for:
    - 3 Total Sulfur
    - 15 Siloxane
    - 3 Ammonia
    - 15 VOCs

MAINTENANCE

- Hydrogen Sulfide Removal System

    - Clean Hydrogen Sulfide Inlet Moisture/Particulate Filter
    - Replace Hydrogen Sulfide Media
    - Estimated Cost = $27,800*
    - Estimated Media Life = 130 days for lead vessel @ 1,000ppmv

    **Labor for change out, disposal and shipping of media not included*

- Gas Compression/Moisture Removal System

    - Clean Gas Compressor Inlet Moisture/Particulate Filter
    - Replace Oil Particulate Filters
    - Change Oil Separator Elements
    - Change Compressor Oil
    - Clean Oil Heat Exchangers
    - Clean Glycol Chiller Condenser
    - Test Glycol for Freeze Point
    - Estimated Cost = $5,500*every 12 months

    **Technician Labor and travel expenses not included*

- Siloxane Removal System

    - Replace Siloxane/VOC Removal Media
    - Estimated Cost = $16,000* per change out

- Estimated Media Life = 300 days based on the Dry Creek gas analysis
**Labor for change out, disposal and shipping of media not included*

- Tail Gas Compression/After-Cooler System

    - Replace Oil Particulate Filters
    - Change Oil Separator Elements
    - Change Compressor Oil
    - Clean Oil Heat Exchangers
    - Clean Air to Gas After-Cooler fins
    - Estimated Cost = $2,500*every 12 months

    **Technician Labor and travel expenses not included*

ELECTRICAL PARASITIC

- Electrical Parasitic

    - Condensate Pump = 1 kW
    - Gas Compressor Motor = 99 kW each
    - Oil Cooler Motor = 3 kW each
    - Glycol Chiller = 42 kW
    - Tail Gas Compressor = 41 kW each
    - Air to Gas After-Cooler = 3 kW
    - Controls & Auxiliary Equipment = 4 kW

    Total = 336 kW (Full Load)
    Total = 270 kW (Average Run Load)

DELIVERY SCHEDULE

- Submittals delivered **6** to **8** weeks after order acceptance.
- Delivery is subject to confirmation at the time of submittal approval.

PRICING SUMMARY

- Price includes all labor and expenses associated with the fabrication of the system.
- Prices do not reflect any taxes that may be applicable and are valid for 30 days.
- Price is FCA; Factory, Dubuque, IA 52002, per Incoterms 2010. Shipping costs included.
- Price does includes Start-up and Commissioning per Manufacturer's Field Services listed above.

Biogas Upgrading per Scope of Supply and 90% Specification Section 43 32 77 .... $2,648,150.00

PAYMENT SCHEDULE

startup and comm: $73,725
shipping: $48,750

- 30% at submittal approval
- 30% at midpoint of construction
- 30% upon equipment ready to ship
- 10% upon start-up not to exceed 180 days from shipment
- Net 30 days on all payments

PROVIDED BY OTHERS

- VPN connection for remote access to Unison supplied equipment for troubleshooting and remote assistance.

PRICE DOES NOT INCLUDE

- Shipping of equipment to jobsite, in equipment pricing
- Start-up and commissioning services, in equipment pricing
- Any maintenance work after start-up
- H_2S or Siloxane/VOC removal media after initial fill
- Performance guarantee or service/maintenance contract
- Any gas testing or analyses
- Permitting for the installation of the equipment or air permits
- Freeze protection; including insulation and/or heat trace and heat trace power
- Pipe stands for field piping
- Anchor bolts
- Product Gas testing equipment per Section 43 32 77 pg 43, 3.03/1.g.4 of the specs

ASSUMPTIONS

VESSELS & MEDIA

- H_2S and VOC's present in the gas will foul Siloxane media, additional gas testing will be necessary to finalize all vessel and media requirements, budget pricing is dependent on gas data given at the time of the proposal.
- Any assumption of media life that has been given is an estimate; additional gas testing will be required at the Buyer/Owner/End Users expense.
- Vessel sizes are estimates only, gas testing will be necessary to finalize all vessel sizing.

MECHANICAL

- Flare is supplied by OTHERS
- If an existing flare is being used, it is assumed this flare is in good working order, with all safety and control equipment.
- Foundations and/or maintenance pads are designed by OTHERS to properly support the equipment.

ELECTRICAL

- 480V/3Ph/60Hz is available
- 120V/3Ph/60Hz is available

INSTALLATION CONTRACTOR RESPONSIBILITIES

- Installation responsibilities are broken out below into three categories to outline the work; these responsibilities by no means fall on any single contractor or individual. It is the responsibility of the Buyer/Owner/End User to ensure all these conditions are adhered to, as necessary. It is responsibility of the Buyer/Owner/End User to install all equipment in compliance with local and national codes applicable to the installation site.

BUYER/OWNER/END USER RESPONSIBILITIES

- All foundations and/or maintenance pads as necessary for equipment
- Provide and seal all roof and building penetrations as necessary
- Provide all anchor bolts, temporary lift equipment, power, labor, and all other incidentals required for proper installation of the equipment shown on the drawings that will be provided by Unison Solutions, Inc.
- All rigging and setting of equipment at job site
- Proper storage of the equipment and media prior to installation
- Provide installation of Equipment/Sub-systems per the Unison Solutions Installation Guide
- Load initial charge of Hydrogen Sulfide Media and Siloxane/VOC Media into the vessels

MECHANICAL CONTRACTOR RESPONSIBILITIES

- Provide all field piping between the Equipment/Sub-systems, including but not limited to:
    - Hydrogen Sulfide Removal System
    - Gas Compression/Moisture Removal/Siloxane/VOC Removal System
    - Tail Gas Compression and Natural Gas Blending Systems
    - Glycol Chiller
    - Gas Analysis System
- Provide pipe supports as necessary. Piping shall be self-supporting, and not supported off of the Unison supplied equipment.
- Install all field located or shipped loose devices
- Provide all Heat Trace and/or Insulation as necessary to provide proper freeze protection as defined by Unison Solutions.

ELECTRICAL CONTRACTOR RESPONSIBILITIES

- Provide 480V/3Ph/60Hz feed to the Gas Conditioning System Control Panel, Gas Compressor VFD Panels, and Glycol Chiller.
- Provide all field wiring and conduits between the Equipment/Sub-systems to the Gas Conditioning Control Panel and associated equipment. This includes but not limited to:
    - Hydrogen Sulfide Removal System
    - Gas Compression/Moisture/Siloxane/VOC Removal System Removal
    - Tail Gas Compression and Natural Gas Blending Systems
    - Glycol Chiller
    - Gas Conditioning System Control Panel
    - Wall Mount VFDs (5x total)
    - Transformer
    - Gas Analysis System
- Provide local disconnects as necessary
- Provide all Hazardous location conduits & wiring systems per Article 500 of the NEC

- Provide conduit seals entering and/or leaving the Class I, Division 1 Electrical Area. Conduit seals will need to be filled during Start-up and Commissioning after verification of field wiring by Unison's Start-up Technician. Conduit seals are to be filled prior to the introduction of gas to the equipment.
- Provide heat trace power from local lighting panel, as necessary.

WARRANTY

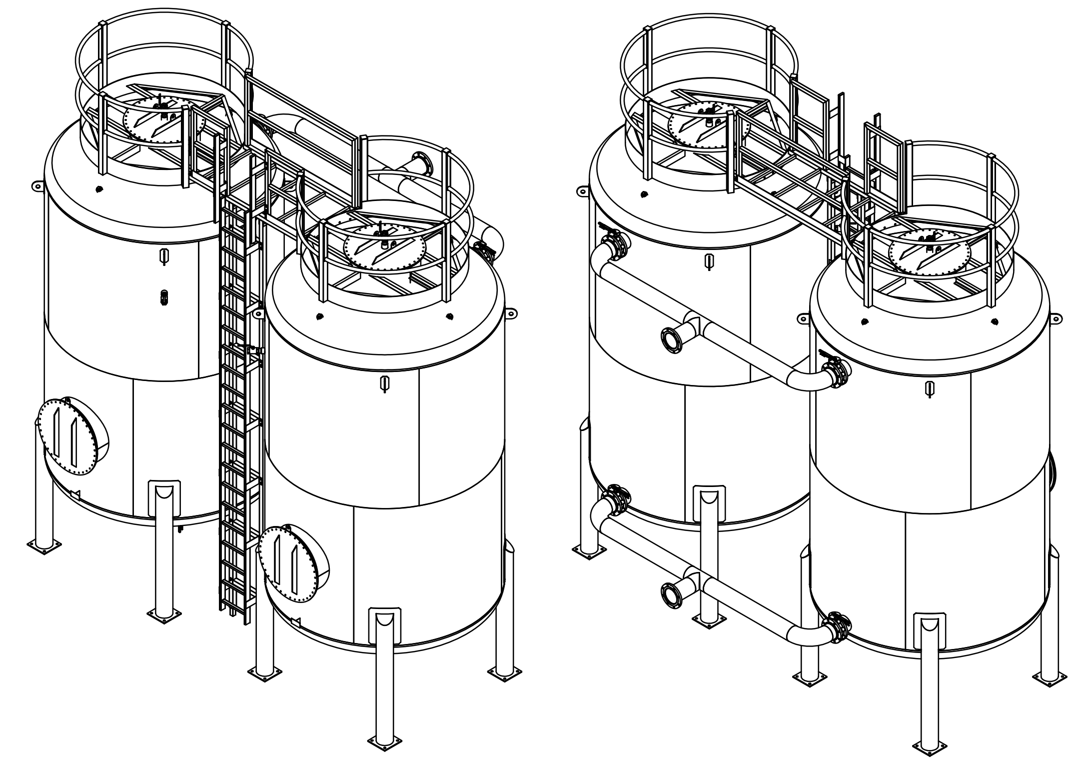
- Unison Solutions, Inc. will warrant all workmanship and materials in conformance with the attached Warranty Statement. Warranty is valid for **18** months from the time the equipment is shipped from Unison's factory or **12** months from the date of startup, whichever occurs first.

- This proposal is for equipment only and does not include any system engineering and design services expressed or implied.

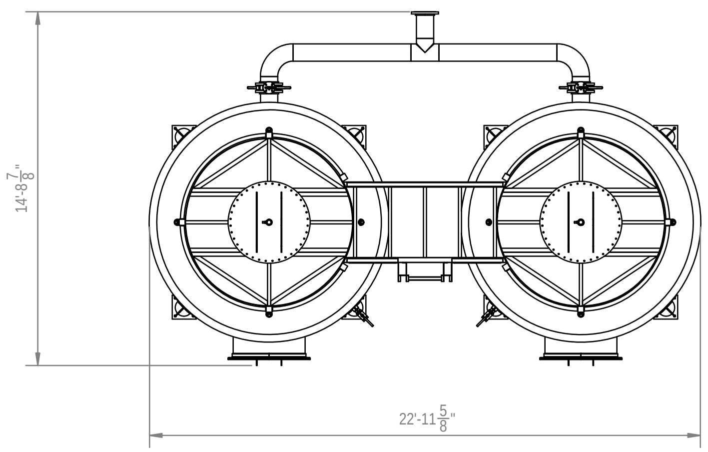
- Unison Solutions, Inc. will not release the PLC program for this system. This is considered proprietary and the intellectual property of Unison Solutions, Inc.

REVISIONS				
REV.	BY	APPRVD	DATE	DESCRIPTION

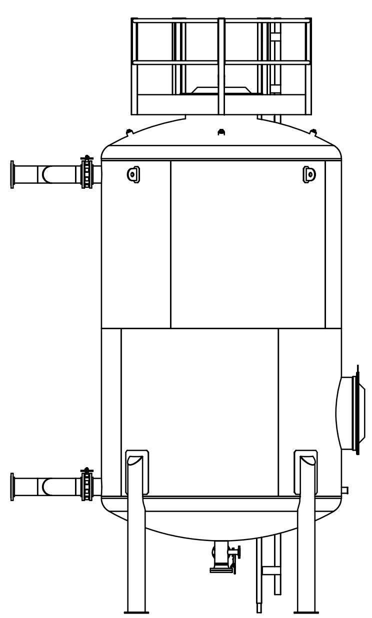
ISOMETRIC VIEW



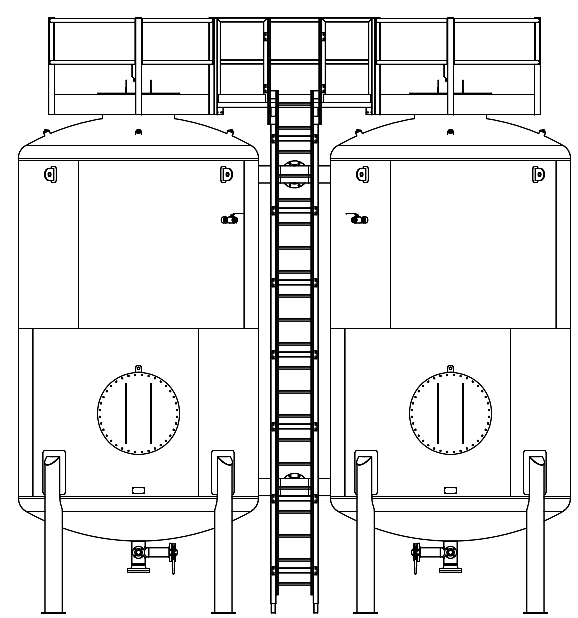
TOP VIEW



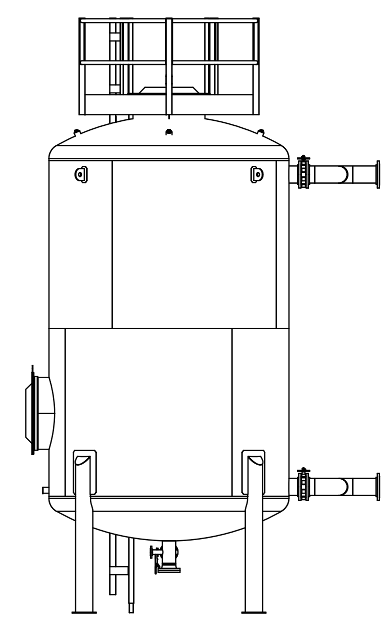
LEFT VIEW



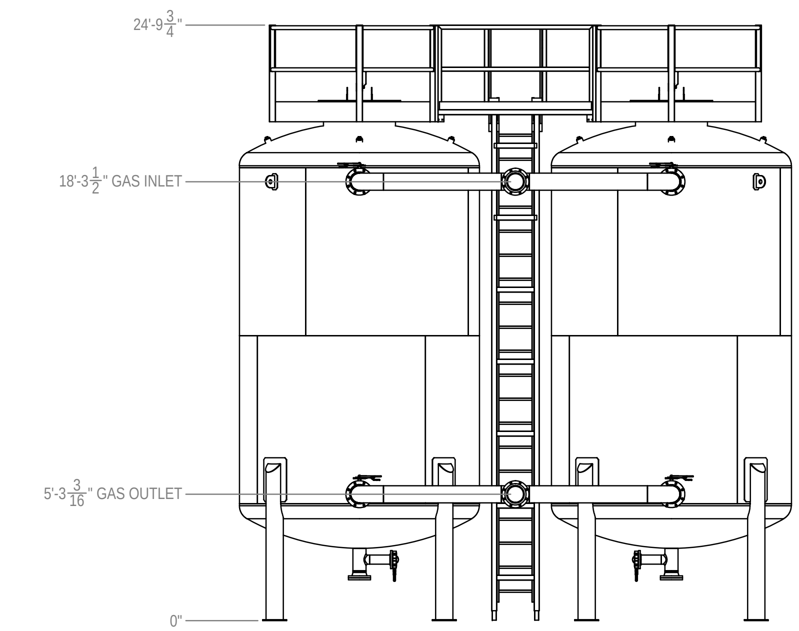
FRONT VIEW



RIGHT VIEW



REAR VIEW



NOT FOR CONSTRUCTION

DIMENSIONS FOR REFERENCE ONLY
AND ARE SUBJECT TO CHANGE

PRELIMINARY LAYOUT

APPROVED BY:

DATE:

THIRD ANGLE PROJECTION

NOTES:	MANUFACTURING TOLERANCE (UNLESS SPECIFIED)	
	0.001 =+/-0.063 ANGULAR=+/-1° BREAK ALL SHARP EDGES ALL DIMENSIONS ARE IN INCHES UNLESS OTHERWISE SPECIFIED	
	SCALE:	NTS
	DRAWN BY:	TAB DATE: 2/10/2017
	CHECKED:	
	ENGINEER:	
	RELEASED:	

UNISON SOLUTIONS

Unison Solutions Inc.
5451 Chavenelle Road
Dubuque, IA 52002

PHONE: 563-585-0967
FAX: 563-585-0970

PROJECT: **BioCNG-400 ROSEVILLE**

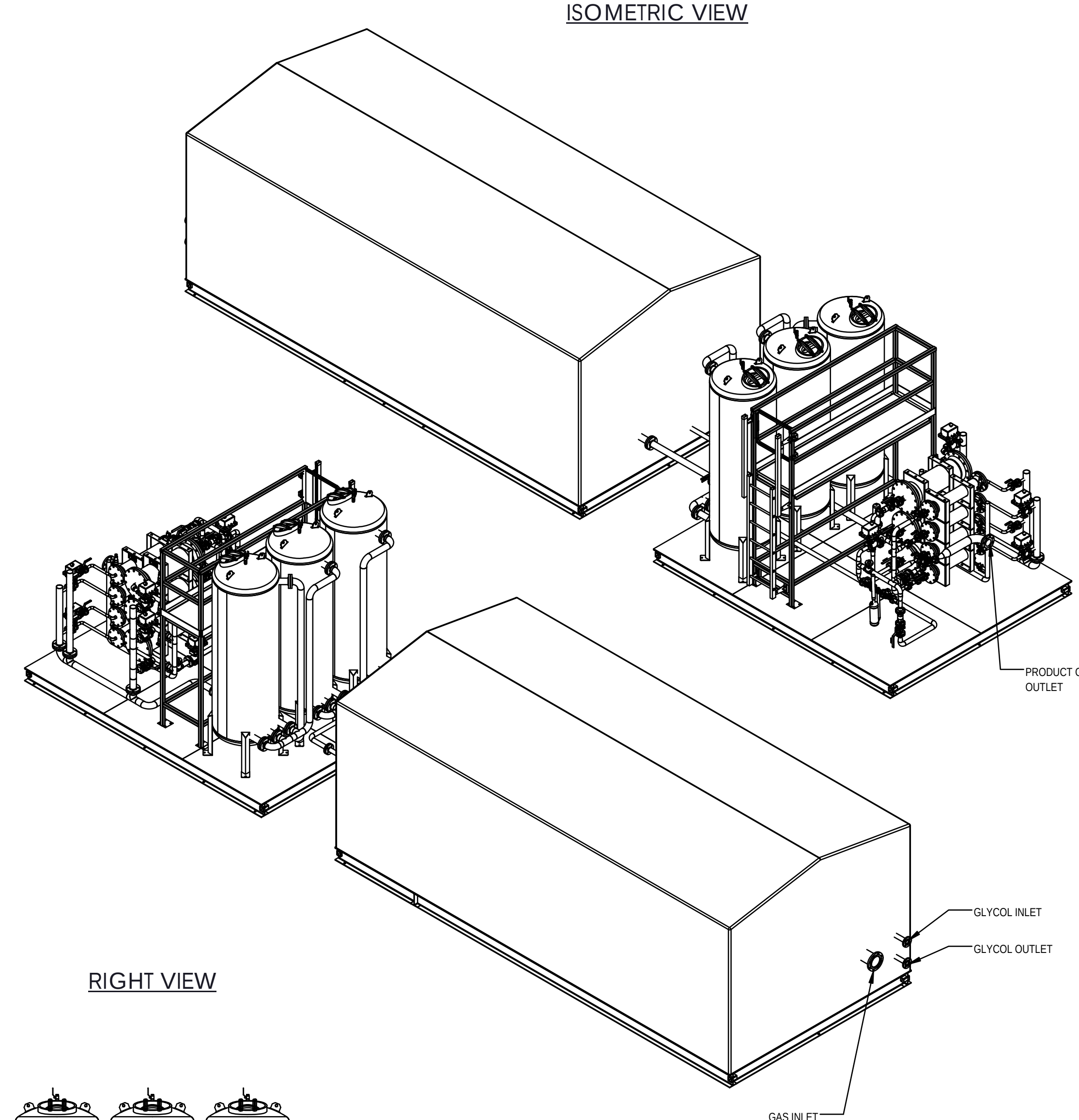
DESCRIPTION: **HYDROGEN SULFIDE REMOVAL SYSTEM**

DRAWING NO. **6**

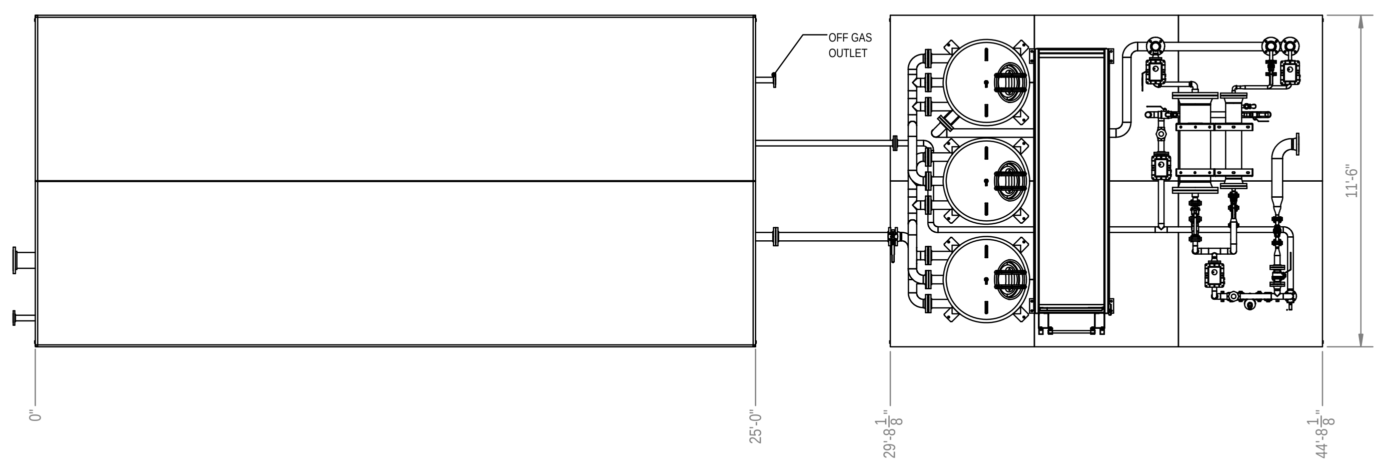
WEIGHT	SIZE	SHEET No.	REVISION
	D	1 of 1	

REVISIONS				
REV.	BY	APPRVD	DATE	DESCRIPTION

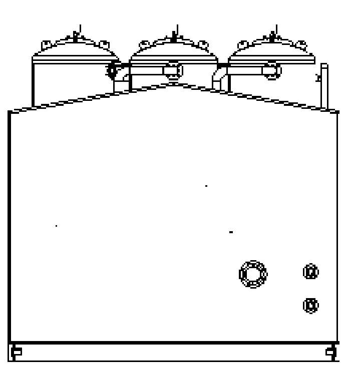
ISOMETRIC VIEW



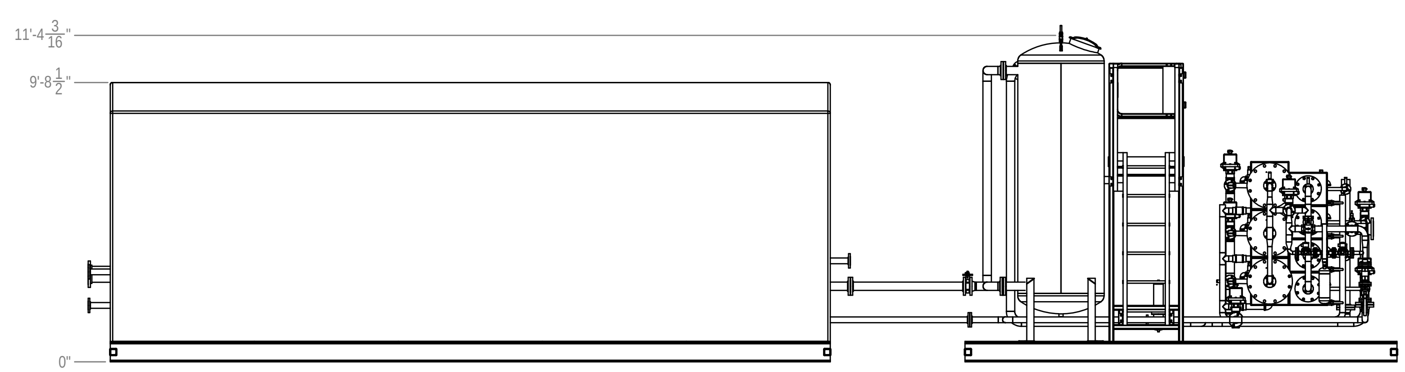
TOP VIEW



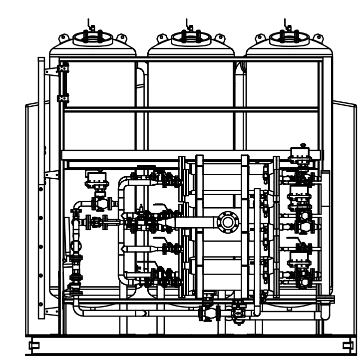
LEFT VIEW



FRONT VIEW



RIGHT VIEW



PRELIMINARY LAYOUT

APPROVED BY:

DATE:

NOT FOR CONSTRUCTION

DIMENSIONS FOR REFERENCE ONLY
AND ARE SUBJECT TO CHANGE

THIRD ANGLE PROJECTION

NOTES:	MANUFACTURING TOLERANCE (UNLESS SPECIFIED)	
CONDUIT/STANDS/INSTRUMENTATION NOT SHOWN	0.001 =+/-0.063 ANGULAR=+/-1• BREAK ALL SHARP EDGES ALL DIMENSIONS ARE IN INCHES UNLESS OTHERWISE SPECIFIED	
	SCALE:	NTS
	DRAWN BY:	TAB DATE: 2/10/2017
	CHECKED:	
	ENGINEER:	
	RELEASED:	

UNISON SOLUTIONS

Unison Solutions Inc.
5451 Chavenelle Road
Dubuque, IA 52002

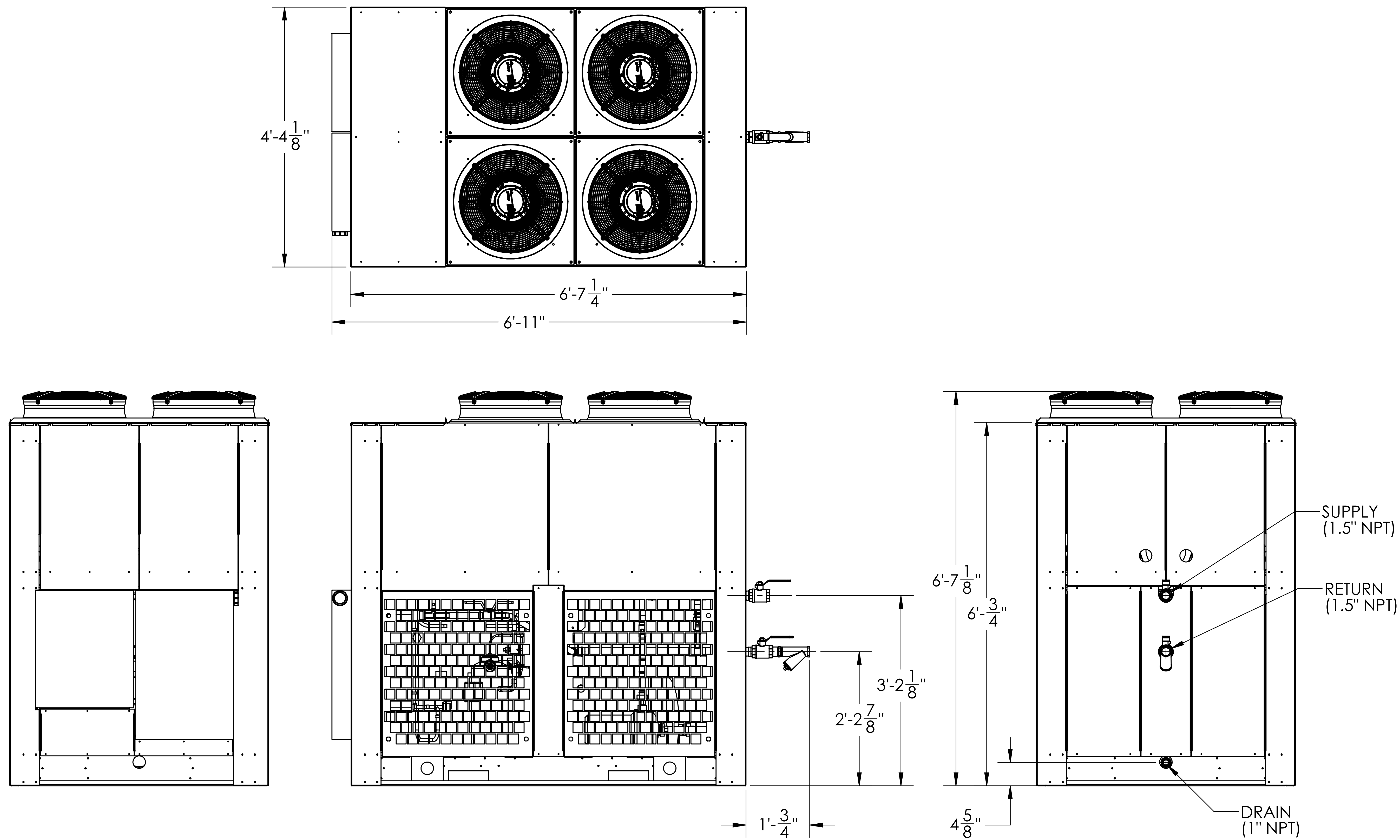
PHONE: 563-585-0967
FAX: 563-585-0970

PROJECT: **BioCNG-400 ROSEVILLE**

DESCRIPTION: **BIOCNG400**

DRAWING NO.

WEIGHT	SIZE	SHEET No.	REVISION
	D	1 of 1	



JTS 20DIA

PART	
CONFIG.	
MATERIAL	
FINISH	
NOTES	

SIZE	REV
B	0
SCALE: 1:20	SHEET 2 OF 4

	NAME:	DATE:
DRAWN	Dave Odell	2/7/2013
REVIEWED	Bryce Waite	2/6/2013
Q.A. APPR.		
CLIENT APPR.		
RELEASED TO MFG.		

PROJECT:
JTS 20DIA
DWG. NO.
JTS 20DIA-M020
REQUIRED CLEARANCES

JOHNSON THERMAL SYSTEMS
1505 Industrial Way
Caldwell, ID 83605
WWW.JohnsonThermal.com

Engine Vendor Quotes

Jenbacher - Rochester WWTP Budgetary Pricing

	JMS320	(2) JMS320
Power (kWe) =	1,065	2,130
Energy Input (Mbtu/hr) =	9,199	18,398
Energy Consumption (SCFM based on 550 btu/cuft) =	279	558
Electrical Efficiency =	39.5%	39.5%
Thermal Energy with Exhaust Heat Recovery (Mbtu/hr) =	4,367	8,734
JENBACHER SUPPLY		
JMS, Generator Set with Heat Recovery, Biogas Version D805 - 480V		
Dual fuel blending at load		
NFPA special gas train adder		
Exhaust gas heat exchanger (not ASME stamped)		
Exhaust gas bypass valve (valve, control hardware and software)		
M1 Panel air conditioning unit		
A1 Panel air conditioning unit		
Ventilation Fan Control, Option 1		
Ventilation System Louver Control		
Engine Vibration Sensor		
Modbus		
OPC (located in Winserver)		
Hot water Pump (panel control parts & SW only)		
Hot water Monitoring (panel control parts and SW only)		
Hot water temperature control (panel parts and SW only)		
Intercooler Temperature Control (panel parts and SW only)		
Intercooler Loop Pump Control (panel parts and SW only)		
Intercooler Loop pressure switch (panel parts and SW only)		
Fan Control/Protection/Contacts for 2 circuit radiator		
Gas Flow meter trending		
Grid parallel with kW Power Control		
Grid parallel with import/export control		
Blackout starting capability		
Grid Parallel with island mode option 3		
Master Synchronization panel (2-4 units)		
Measurement & Protection CTs		
2.99d UK Electric Metering Package		
Diane RMC (remote message control) with startup (once per site)		
2nd year of warranty		
	Sub total =	$1,009,186
ELECTRICAL SWITCHGEAR		
(1) Low Voltage Switchgear - 1 GCB, FCB and UCB with protection		
(1) Shipping		
	Sub total =	$161,765
BALANCE OF PLANT		
(1) Guntner Remote V-Type HT/LT radiators designed for 100°F ambient, 50% prop glycol		
Freight for the Radiator from Laredo, TX		
(2) 4" HT Radiator water flexes		
(2) 3" LT Radiator water flexes		
(1) LT electric coolant pump		
(1) LT Flow control valves FCH1		
(1) LT Expansion Tank NTW2		
(1) LT Misc gauges, valves, PRV, transducer, etc		
(1) LT warmup Amot valves TCV3		
(1) HT electric coolant pump		
(1) HT Thermal expansion tank & bands NTW3		
(1) HT Misc gauges, valves, PRV, transducer, etc		
(1) HT Clorius electronic temperature valve, TCV5 or equal		
(1) Exhaust Flexes for silencer		
(1) Exhaust silencer		
(1) Metering package (fuel flow, power net, power parasitic)		
(1) Lube oil tanks - clean and used		
Frt on above		
	Sub total =	$206,078
DELIVERY and SITE COMMISSIONING		
Origin Charges: Ocean Freight, BAF, CAF, Pre-carriage Door, AMS, Customs, BOL		
Destination Charges: Entry Fee, Import Fee, Duties, Fees, Delivery to Site		
Precommissioning: 4 days on site per unit		
Precommissioning Travel: 2 trips		
Commissioning preparation documentation: 1 day in office		
Commissioning on site: 15 days on site per unit		
Commissioning Travel: 4 trips		
After commissioning documentation: 3 days in office		
Lube oil and Glycol first fill, for engine circuit		
Engineering review of product design/use and review of equipment		
	Sub total =	$185,133
	Total Budgetary Price =	$1,562,162
	$ / kWe =	$733.41

SIEMENS	GROUP: IC	GAS	PRODUCT INFORMATION: IC-G-B-42-059	INDEX: 1
	POWER RATING		DATE: 20/12/16	DEP.: 2

GENSET:	**SGE-42HM**	**SPEED:**	**1800**
JACKET WATER TEMPERATURE(°F):	**194**	**FUEL TYPE:**	**SEWAGE GAS**
INTERCOOLER WATER TEMP(°F):	**131**		

SERVICE:	**CONTINUOUS**	COMPRESSION RATIO:	**11,9:1**
COOLING SYSTEM:	**TWO CIRCUITS**	REGULATION:	**Electronic**
	TWO STAGE IC / Oilcooler in main circuit	IGNITION TIMING:	**21º**
EXHAUST MANIFOLD TYPE:	**DRY**	MAX. BACK PRESSURE:	**18 "H2O (450 mmH2O)**
EMISSIONS:			

NO_x	g/bHPh	**1**	
CO	g/bHPh	**<2.2**	
NMHC	g/bHPh	**<0.7**	
CH_4	g/bHPh	**<3**	
CO_2	lb/h	**1669**	

AMBIENT CONDITIONS ISO 3046/1:

Atmospheric pressure ("Hg (kPa))=	**30 (100)**
Ambient temperature (°F (°C))=	**77 (25)**
Relative humidity (%)=	**30**

up to 46 percent thermal efficiency.

up to 49 percent thermal efficiency.

POWER RATING (4)			NOMINAL	PARTIAL LOADS		
LOAD		%	**100%**	80%	60%	40%
MECHANICAL POWER	(3, 4, 5)	BHP (KWb)	**1395 (1040)**	1116 (832)	837 (624)	558 (416)
BMEP		psi (bar)	**239 (16.5)**	192 (13.2)	144 (9.9)	96 (6.6)
ELECTRICAL POWER (cosφ 1)	(9)	kWe	**1007**	805	601	395
ELECTRICAL POWER (cosφ 0,8)	(9)	kWe	**997**	798	597	392
FUEL CONSUMPTION	(1)	BTU/bHP-hr (KW)	**6005 (2455)**	6189 (2024)	6409 (1572)	6855 (1121)
MECHANICAL EFFICIENCY		%	**42.4**	41.1	39.7	37.1
ELECTRICAL EFFICIENCY (cosφ 1)	(9)	%	**41.0**	39.8	38.2	35.2
HEAT IN MAIN WATER CIRCUIT	(1)	BTU/min (KW)	**32640 (574)**	27180 (478)	21610 (380)	16440 (289)
HEAT IN SECONDARY WATER CIRCUIT	(1)	BTU/min (KW)	**3242 (57)**	2616 (46)	1877 (33)	1308 (23)
HEAT IN CHARGE COOLER	(1)	BTU/min (KW)	**3242 (57)**	2616 (46)	1877 (33)	1308 (23)
HEAT IN OIL COOLER	(1)	BTU/min (KW)	*******	***	***	***
HEAT IN EXHAUST GASES (25 ºC)	(1)	BTU/min (KW)	**40600 (714)**	34690 (610)	27810 (489)	20360 (358)
HEAT IN EXHAUST GASES (120ºC)	(1)	BTU/min (KW)	**31790 (559)**	27500 (483)	22320 (393)	16620 (292)
EXHAUST GAS TEMPERATURE	(1)	°F (°C)	**865 (463)**	903 (484)	946 (508)	1004 (540)
HEAT TO RADIATION	(1)	BTU/min (KW)	**3981 (70)**	3298 (58)	2616 (46)	1990 (35)
CARBURETION SETTINGS (2)						
O_2 TO EXHAUST(DRY)(ONLY A REFERENCE)		%	**8.6**	8.5	8.2	7.9
MASS FLOWS						
INTAKE AIR FLOW	(1)	lb/h (Kg/h)	**10260 (4650)**	8350 (3790)	6350 (2880)	4350 (1980)
EXHAUST GAS FLOW (WET)	(1)	lb/h (Kg/h)	**11230 (5100)**	9160 (4150)	6970 (3160)	4800 (2180)

NOTES:

1. ALL VALUES ASUME LHV OF THE GAS. 100% LOAD TOLERANCES:
   FUEL CONSUMPTION +5%,
   COOLING CIRCUIT AND EXHAUST GASES ± 8%, RADIATION ±25%
   EXHAUST TEMPERATURE ±20°C, MASS FLOWS ± 10% (ALSO FOR CO2 FLOW IN EXHAUST).
2. THE ENGINE PERFORMANCE DATA, TIMING ADVANCE AND CARBURETION SETTINGS ARE VALID FOR A BIOGAS THAT FULFILS THE REQUIREMENTS DEFINED IN IC-G-D-30-001e AND IC-G-D-30-003e. HEAT BALANCE FOR A REFERENCE GAS: CH4 67%, CO2 33%
3. NET POWER, MECHANICAL PUMPS NOT INCLUDED.
4. POWERS ARE VALID FOR AMBIENT TEMP.=77ºF (25ºC) AND AN ALTITUDE OF =1640 ft (500 m). SEE OTHER CONDITIONS IN PI IC-G-B-00-005
5. OVERLOAD NOT ALLOWED. IT IS NOT RECOMMENDED TO OPERATE BELOW 40% LOAD DURING LONG TIME.
6. THE SPECIFICATIONS AND MATERIALS ARE SUBJECT TO CHANGE WITHOUT NOTIFICATION
7. A ENGINE WITH INLET OR OUTPUT RESTRICTION OVER PUBLISHED LIMITS, OR WITH INADEQUATE MAINTENANCE OR INSTALLATION CAN MODIFY POWER RATING DATA.
8. EMISSIONS ACCORDING TO D1 CYCLE IS 8178-4.
9. ALTERNATOR VOLTAGE 480 V
10. **ONLY IN PARALLEL TO THE GRID OPERATION**

SIEMENS	GROUP	GAS	PRODUCT INFORMATION	INDEX
	IC		IC-G-B-56-102	D1
	POWER RATING		DATE 15/05/17	DEP. 2

GENSET:	**SGE-56HM**	**SPEED:**	**1200**
JACKET WATER TEMPERATURE(°F):	**194**	**FUEL TYPE:**	**SEWAGE GAS**
INTERCOOLER WATER TEMP(°F):	**131**		

SERVICE:			**CONTINUOUS**	COMPRESSION RATIO:	**11,9:1**
COOLING SYSTEM:			**TWO CIRCUITS**	REGULATION:	**Electronic**
			TWO STAGE IC	IGNITION TIMING:	**21º**
EXHAUST MANIFOLD TYPE:			**DRY**	MAX. BACK PRESSURE:	**18 ''H2O (450 mmH2O)**
EMISSIONS:					
	NO_x	g/bHPh	**1**	AMBIENT CONDITIONS ISO 3046/1:	
	CO	g/bHPh	**<2.2**	Atmospheric pressure (''Hg (kPa))=	**30 (100)**
	NMHC	g/bHPh	**<0.7**	Ambient temperature (°F (°C))=	**77 (25)**
	CH_4	g/bHPh	**<3**	Relative humidity (%)=	**30**
	CO_2	lb/h	**1672**		

POWER RATING (4)			NOMINAL	PARTIAL LOADS		
LOAD		%	**100%**	80%	60%	40%
MECHANICAL POWER	**(3, 4, 5)**	BHP (KWb)	**1395 (1040)**	1116 (832)	837 (624)	558 (416)
BMEP		psi (bar)	**270 (18.6)**	216 (14.9)	161 (11.1)	107 (7.4)
ELECTRICAL POWER (cosϕ 1)	**(9)**	kWe	**1011**	807	602	396
ELECTRICAL POWER (cosϕ 0,8)	**(9)**	kWe	**1000**	800	598	394
FUEL CONSUMPTION	**(1)**	BTU/bHP-hr (KW)	**6015 (2459)**	6140 (2008)	6368 (1562)	6763 (1106)
MECHANICAL EFFICIENCY		%	**42.3**	41.4	39.9	37.6
ELECTRICAL EFFICIENCY (cosϕ 1)	**(9)**	%	**41.1**	40.2	38.5	35.8
HEAT IN MAIN WATER CIRCUIT	**(1)**	BTU/min (KW)	**28380 (499)**	22290 (392)	17120 (301)	12620 (222)
HEAT IN SECONDARY WATER CIRCUIT	**(1)**	BTU/min (KW)	**10180 (179)**	8644 (152)	7507 (132)	6142 (108)
HEAT IN CHARGE COOLER	**(1)**	BTU/min (KW)	**3469 (61)**	2445 (43)	1877 (33)	1081 (19)
HEAT IN OIL COOLER	**(1)**	BTU/min (KW)	**6711 (118)**	6199 (109)	5630 (99)	5061 (89)
HEAT IN EXHAUST GASES (25 ºC)	**(1)**	BTU/min (KW)	**38390 (675)**	32640 (574)	25880 (455)	18310 (322)
HEAT IN EXHAUST GASES (120ºC)	**(1)**	BTU/min (KW)	**29030 (511)**	25020 (440)	20070 (353)	14400 (253)
EXHAUST GAS TEMPERATURE	**(1)**	°F (°C)	**779 (415)**	811 (433)	842 (450)	876 (469)
HEAT TO RADIATION	**(1)**	BTU/min (KW)	**3753 (66)**	3298 (58)	2843 (50)	2161 (38)
CARBURETION SETTINGS (2)						
O_2 TO EXHAUST(DRY)(ONLY A REFERENCE)		%	**9.1**	9.0	8.8	8.5
MASS FLOWS						
INTAKE AIR FLOW	**(1)**	lb/h (Kg/h)	**10930 (4960)**	8880 (4030)	6740 (3060)	4550 (2060)
EXHAUST GAS FLOW (WET)	**(1)**	lb/h (Kg/h)	**11930 (5410)**	9690 (4400)	7370 (3340)	5000 (2270)

NOTES:

1. ALL VALUES ASUME LHV OF THE GAS. 100% LOAD TOLERANCES:
   FUEL CONSUMPTION +5%,
   COOLING CIRCUIT AND EXHAUST GASES ± 8%, RADIATION ±25%
   EXHAUST TEMPERATURE ±20°C, MASS FLOWS ± 10% (ALSO FOR CO2 FLOW IN EXHAUST).
2. THE ENGINE PERFORMANCE DATA, TIMING ADVANCE AND CARBURETION SETTINGS ARE VALID FOR A BIOGAS
   THAT FULFILS THE REQUIREMENTS DEFINED IN IC-G-D-30-001e AND IC-G-D-30-003e. HEAT BALANCE FOR A REFERENCE GAS: CH4 62.5%, CO2 36%, N2 1,5%
3. NET POWER, MECHANICAL PUMPS NOT INCLUDED.
4. POWERS ARE VALID FOR AMBIENT TEMP.=77ºF (25ºC) AND AN ALTITUDE OF =1640 ft (500 m). SEE OTHER CONDITIONS IN PI IC-G-B-00-005
5. OVERLOAD NOT ALLOWED. IT IS NOT RECOMMENDED TO OPERATE BELOW 40% LOAD DURING LONG TIME.
6. THE SPECIFICATIONS AND MATERIALS ARE SUBJECT TO CHANGE WITHOUT NOTIFICATION
7. A ENGINE WITH INLET OR OUTPUT RESTRICTION OVER PUBLISHED LIMITS, OR WITH INADEQUATE MAINTENANCE OR INSTALLATION
   CAN MODIFY POWER RATING DATA.
8. EMISSIONS ACCORDING TO D1 CYCLE IS 8178-4.
9. ALTERNATOR VOLTAGE 480 V
10. **ONLY IN PARALLEL TO THE GRID OPERATION**

SIEMENS

Standard Scope of Supply	Issue: 3.0 Date : Oct. 2018

MODULE	**Generator Set Control and Power Panel**	
	Engine:	**SGE-SL, SGE-SM, SGE-HM**
	Range:	**18, 24, 36, 48, 56**
	Speed:	**1200, 1500 & 1800**
	Fuel:	**N/A**

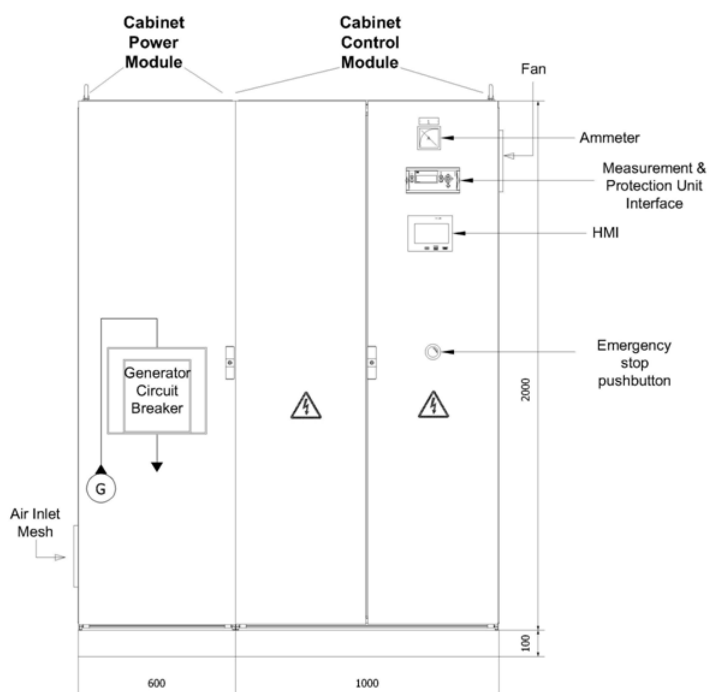
As Feb 2014
To be verified at point of order

➢ *Description*

The Siemens generator set control panel complements the engine and alternator supply to provide integrated, tested and reliable control and power switching.

The control system is provided in two cabinets – a control cabinet and a power cabinet, these can be supplied assembled or as separate parts. The cabinet construction is modular, made from powder coated steel and supplied as two floor standing enclosures. The nominal dimensions will be height 78.7”, depth 23.6” control section width 39.3”, power section width 23.6”. (Optional 4” plinth is available)

The physical appearance of the cabinet is shown in the figures below:



SIEMENS

➢ *Power cabinet: -*

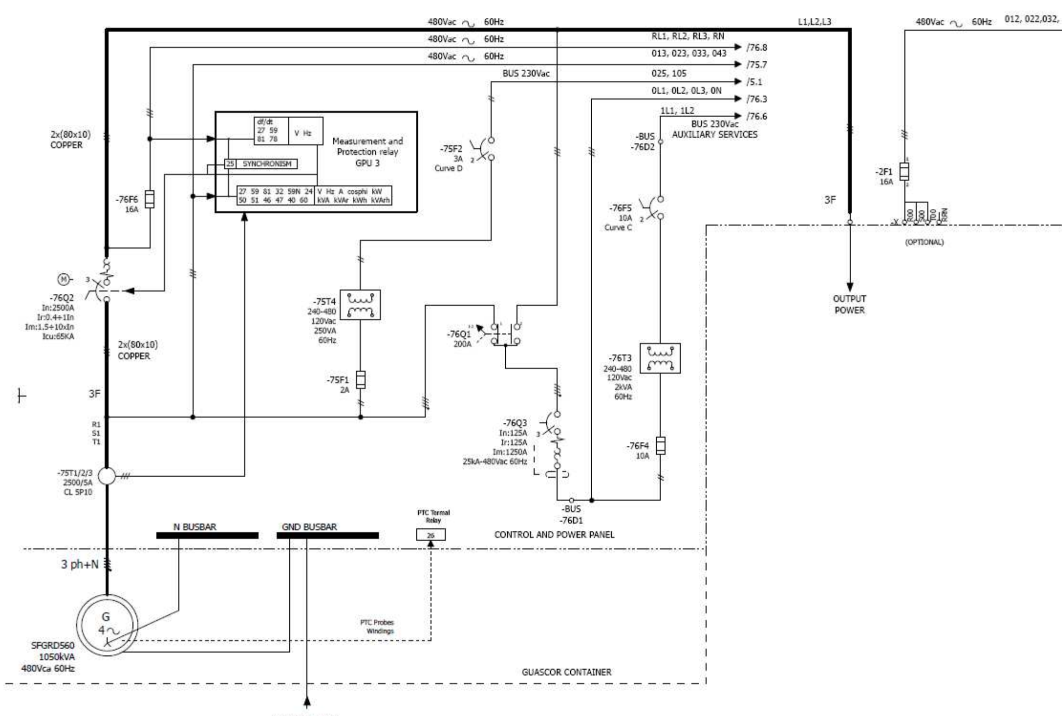
The power cabinet contains the motor actuated breaker to connect the alternator to the load, along with voltage and current monitoring for generator set control protection and metering.
Within the cabinet is the chassis mounted breaker and copper busbar for alternator and customer connections – the busbars are insulated and color coded for safety and identification, the bars are also pre-drilled for ease of connection.

Cable entry to the cabinet is through the base for the power cabling and for control wiring. The cabinet is equipped with an anti-condensation heater and a filtered ventilation opening.

Scope to include:

- *Enclosure, coated steel with single opening door, lifting eyes, connections through the base*
- *Motor actuated spring charge breaker rated for the generator set duty, 3 pole with integral overcurrent protection, under-voltage release and status indication.*
- *Current transformers rated to the generator set duty, protection class 5P10, located on the alternator side of the breaker, to measure the generator current (gross)*
- *Copper bus bar – rated for the operating duty and alternator fault current. Insulated and color identified.*
- *Voltage transformers – step down to provide monitoring and control voltage level for the control side of the panel, voltage transformers are provided on both the load and alternator side of the breaker.*
- *Auxiliary power take off – a supply from the load side of the breaker to an isolator switch, to be used to supply the auxiliary system of the control panel and generator set package.*

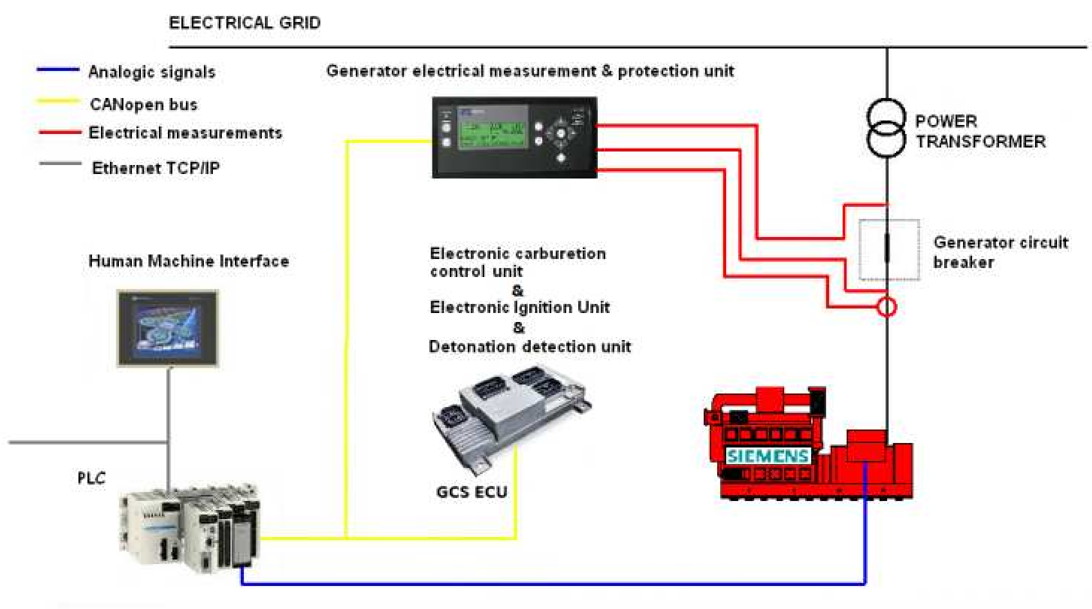
Simplified one-line diagram – for information only



➢ *Control Cabinet*

The control cabinet contains the integral parts of the generator set control system, supplied as a single two door enclosure designed to integrate and sit along-side the power panel – but can but mounted remote from the power panel with an option wire harness.
The generator set will be supplied pre-wired to a junction box, this junction box will then wire to the control panel to provide communications with the generator set.

- *The key parts of the control system are:*
  - *PLC and touchscreen HMI*
  - *Generator control module – for protection, measurement and synchronization*
  - *Engine Control unit GCS-E (engine mounted)*
  - *Ancillary systems power and control*
  - *Battery charging*
  - *Communications interface*
- *The architecture of the control system is shown in the sketch below:*



➢ *Control cabinet functionality*

Power panel control

- *Generator side voltage measurement: Direct taps or step-down transformers provide voltage sensing of the generator voltage for control and monitoring*
- *Load side voltage measurement: Direct taps or step-down transformers provide voltage sensing of the mains (utility) voltage for control, synchronization and protection*
- *Generator current measurement: Bus-bar mounted CT's between the generator and the breaker provide current measurement of the generator (gross), used for power measurement and protection*
- *Generator circuit breaker control: Open and Close orders of the generator sync breaker*
  The circuit breaker has the following elements:
  - *Spring actuated motor operator*

- *Remote closing release*
- *Under-voltage release*
- *Volt-free contacts for indication of status (open/closed) and trips*
- *The voltage for control will be 120 VAC*

– *Depending on the application two configurations for breaker closing are possible:*
  - *Direct closing - without synchronization ("Black start"). Load voltage sensing must show no volts*
  - *Closing with synchronization ("start with coupling to the mains")*

– *The under-voltage release coil is fuse protected; it will trip the breaker in the following events:*
  - *Open signal from the PLC.*
  - *Emergency stop.*
  - *Open signal from the generator electrical protection unit in the event of a protection trip.*

Control system power supply

– *The control system is supplied with 24 VDC from a rectifier and 2 battery systems, the main starting batteries and a set of panel auxiliary batteries. The main starter batteries are placed on the generator set base-frame – primary use engine starting secondary use dc power for control system.*

– *The panel auxiliary batteries are placed inside the cabinet. They provide dc and backup power for a series of critical services (power to the PLC and multifunction protection unit and maintain event and data logging), maintaining autonomy in absence of the mains power and during engine cranking to avoid main battery voltage dip. They are isolated from the main batteries by a diode bridge to avoid reverse discharge.*

– *The cabinet has an electronic rectifier/battery charger with an output of 24 VDC and 20A. The power supply to feed this equipment will be 3 phase taken from the auxiliary service feed.*

– *The main circuits supplied by the 24VDC rectifier/batteries system are:*
  - *PLC & HMI*
  - *Under-voltage relay to monitor the 24 Vdc voltage supply*
  - *Generator protection and measurement unit*
  - *Engine control unit GCS-E*
  - *Emergency stop relay*
  - *Cranking motor.*
  - *Gas ramp.*
  - *Pre-lube pump.*

Emergency Stop

– *The generator set is equipped with 2 emergency stop push-buttons: one alongside the engine and the other on the cabinet door. Pushing either of them will activate the safety relay.*

– *The safety relay will safely perform the following functions when activated:*

– *It will open the generator circuit breaker*

– *It will cut off the fuel supply to the engine, stopping it.*

– *It will stop the pre-lube pump (both in manual mode and in automatic mode).*

– *Give an indication to the PLC for signal recognition (NC contact).*

– *The emergency push-button and the safety relay when activated will require manual reset*

Engine Control Unit "GCS-E"

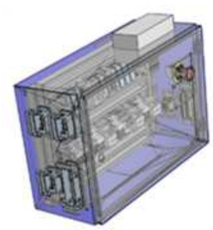
– *GCS-E Engine control unit: The GCS-E is an engine ECU that provides the complete management for safe efficient operation of the engine through integration of the following systems:*
  - *Engine ignition system*

- *Engine carburation / emission control system*
- *Engine speed and load control*
- *Detonation protection system*
- *Engine auxiliary control, start/stop, pre-heat, pre-lube*
- *Engine parameter monitoring*
- *Engine protection and alarms*

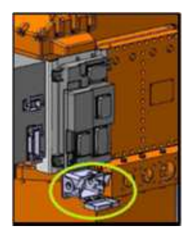
– *The GCS-E also provides customer interfacing through Modbus TCP-IP, CAN J1939 and CAN open*

– *The GCS-E system comprises an ECU, power relay box, harness, customer interface and engine sensors / actuators. All components including ECU and power relay box are engine mounted, the system is completely wired and tested prior to supply.*

– *The GCS-E – ECU: is a single module that is the brain of the control; it integrates control for ignition, carburation, speed and load control, detonation protection, ancillary devices and protection. System configuration is through a single user interface and multiple interface options are available for communication and integration with third party generation or system controllers.*



– *The GCS-E - Power Relay Box: provides the interface between the ECU and the engine ancillaries. The power box requires a 24vdc and a 480v 3 phase AC power supply (by customer) power is then distributed within the box to the ECU as well as the relays and contactors required to operate the included ancillaries (Pre-lube pump, Jacket water heater, starter motor, oil heaters etc). The power box is the location of the engine emergency stop push button.*



– *GCS-e - Harness + Customer Interface connector: The engine is supplied pre-wired through a dedicated wire harness for all included sensors, actuators and ancillaries. Customer interfacing is through a single location using a ruggedized connector (customer interfacing includes – communications, measured power, demand start/stop). After manufacture the engine is tested with the included electrical harness, ancillary devices and ECU installed, ensuring reliable operation and simplified installation and commissioning.*

Generator protection unit

– *The generator protection unit is a multifunction control device that provides protection of the alternator, measurement of the electrical output and synchronization functions. A summary of the function provided is provided below:*

– *Generator protection functions*
  - *Under and over-voltage (ANSI 27/59)*
  - *Under and over-frequency (ANSI 81m/81M)*
  - *Mechanical overload (ANSI 32)*
  - *Reverse power (ANSI 32)*
  - *Overcurrent (2 levels) (ANSI 51)*
  - *Fast Overcurrent (<42 ms) (ANSI 50/51)*

  - *High overcurrent (<350%) (ANSI 50)*
  - *Current unbalance (ANSI 46)*
  - *Voltage asymmetry (ANSI 47)*
  - *Excitation loss from high reactive power consumption*
  - *Over excitation from high reactive power export (ANSI 40)*
- *The measurements carried out and displayed by the unit are:*
  - *Voltage (3 phases)*
  - *Current (3 phases)*
  - *Active power (kW)*
  - *Reactive power (kVar)*
  - *Power factor (cos phi)*
  - *Frequency (f)*
  - *Energy supplied by the generator (kWh)*
- *Generator to plant connecting busbar supervision*
- *Synchronizing*
- *CAN OPEN communication with PLC*

Cooling system control

- *The control system is pre-configured to prove control of the cooling system – (subject to motor size details being provided) Two options are available*
- *Option A - Cooling through a simplified tower. To include the following control:*
  - *Main cooling circuit pump*
  - *Secondary cooling circuit pump*
  - *Cooling tower pump*
  - *Cooling tower fan*
- *Option B – Cooling through air blast coolers. To include the following control:*
  - *Main cooling circuit pump*
  - *Secondary cooling circuit pump*
  - *Air water cooler fans 1 and 2 (1st cooling stage)*
  - *Air water cooler fans 3 and 4 (2nd cooling stage)*
  - *Air water cooler fans 5 and 6 (3rd cooling stage)*
- *The control system will provide thermostatic control of the main and secondary circuit water temperatures based upon the main cooling circuit temperature and the air intake temperature.*
- *The HMI provides mode selection for each circuit (automatic, manual or disabled) and an auxiliary services configuration menu.*
- *In manual mode the respective cooling system will be powered and the motor will start. With the selector in disabled all systems will remain disconnected. With the selector in the automatic mode, the motors will work when the conditions for an automatic start are fulfilled.*

Each motor will be protected by means of a thermal magnetic motor circuit breaker with the appropriate rating. The PLC will receive signals to confirm the operation of the service and a trip of the protection. Both states will be displayed in the HMI. An alarm will be display in the HMI if the protection trips activate or if there is no confirmation of a working condition when the working order is active.

Customer connections

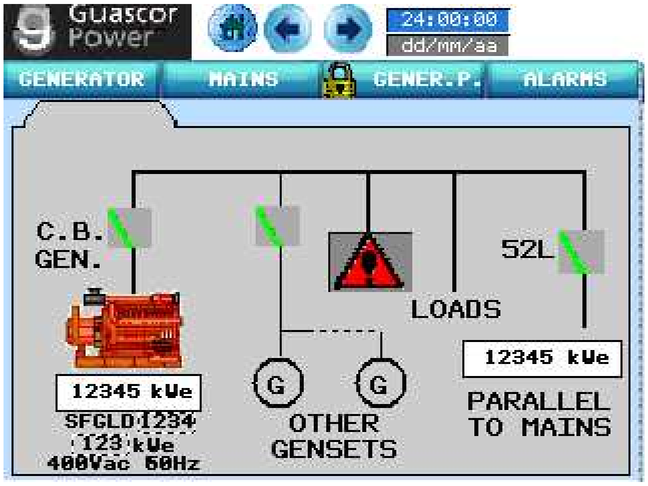
- *The control system provides volt free contacts (VFC) of genset information, available for external connection to other plant equipment. The signals are as follows:*
    - *Genset working*
    - *Genset horn beeping*
    - *Genset general alarm*
    - *Genset circuit breaker status*
    - *Genset connected to the mains*

AVR control

- *The control system provides control of the alternator AVR to maintain correct voltage regulation at synchronization and during island operation, provide voltage matching during synchronization and power factor control during parallel operation.*
- *The AVR parameterization and monitoring is performed through the HMI, alarm states from the AVR and displayed on the HMI.*

PLC and HMI

- *The control system is built around an industrial based PLC with connected HMI. The PLC is programmed to provide reliable and safe operation of the generator set under all operating condition. The control system is configured through parameterization during commissioning and should not require further adjustment between service intervals. The HMI is a color touchscreen graphic terminal installed on the cabinet door (optionally it can be supplied to terminals for remote mounting.*
- *The PLC communicates using CANopen with the modules of the control system (GCS-E, GPU) providing fast reliable communication. The PLC also has an Ethernet TCP/IP port, which provides the communication with similar gensets to share load in islanding operation. In addition the TCP/IP communication port also provides the options for:*
    - *Remote warnings (by GSM or similar, OPTIONAL)*
    - *Data map export to a SCADA (OPTIONAL)*
- *The screen image below is a sample from the base HMI showing the one line operational view:*



Detonation Protection

Recommended for all generator sets

- *The detonation detection system is a module within the GCS-E.*
- *The detonation detection system provides protection against detonation in the cylinders of the engine – an undesirable and detrimental operating condition. The system consists of 2 parts:*
- *The GCS-E control unit processes the information from the sensors and sets the correction action required to eliminate detonation, then reestablish the original values when possible.*
- *Sensors - piezoelectric sensors that provide the vibration signals from the cylinder walls to the GCS-E control unit.*
- *The GCS-E utilizes CANopen communications to transmit all of the relevant information to the PLC (detonation status, load reduction, high priority alarm and ignition timing modification).*
- *The HMI provides parameterization of the system and display of operating data and alarm conditions.*

Options:

- *Other options are available: please contact local distributor or Dresser-Rand for details:*
- *Multi set load sharing and island management*
- *Mains (utility) circuit breaker control*
- *Engine- electric pre-heating*
- *Energy metering*
- *Cylinder exhaust temperatures*
- *Alternator winding and bearing temperature monitoring*
- *Gas pressure and booster control*

Enclosure General Characteristics

- *Interior lighting with door microswitch*
- *120Vac/6A utility socket*
- *Fan Ventilation (optional air conditioning unit)*
- *All ancillaries protected against overcurrent and short circuit.*
- *Auxiliary services feeder with residual current protection*
- *The relays for control purposes will include lockable test button and mechanical interlock.*
- *Protection degree IP54*
- *Cable gland plate for entry of cables and non-protected active parts IP20*
- *Fan and vent grille: IP54*
- *Steel sheet thickness: 2mm.*
- *Epoxy polyester powder coating finish with 50 microns thickness and painted with RAL 7035.*
- *Enclosure labels engraved and fixed with rivets or screws*

Storage Specification

- *Protection rating* — *IP 54 (5: Dust protected and 4 Water splashing against the enclosure from any direction shall have no harmful effect).*
  Cabinet should not be subject to direct sunlight.
- *Resistance against impacts* — *IK 8 (Resistance against impacts with an energy up to 5 JOULE 1,7Kg - 29,5cm)*
- *Storage Temperature* — *-20C to +60C (-4F to +140F)*
- *Relative Humidity* — *85% w/o condensation*

- *Air purity (dust)* *≤ 0,1mg/ m3 (10-7 oz/ft³) (non-conductive levels)*
- *Corrosive gases* *Free of corrosive gases*
- *CAUTION*
- *After a longer storage time the first operation that should be carried out before the start up will be:*
  - *1) Supply the AUXILIARY SERVICES to activate the battery charger and charge the PLC batteries to ensure its operation.*
  - *2) After connect the cabinet with the genset, it shoud be carry out a starting order for the pre-lube pump and the preheating systems before the genset starting.*

WORKING CONDITIONS

- *Indoor use only*
- *Maximum ambient temperature: 40ºC*
- *Maximum continuous temperature over a 24h period: 35ºC.*
- *Minimum ambient temperature: -5ºC*
- *Industrial environment*
- *Pollution degree: 2*
- *Relative humidity lower than 50% for the maximum allowed temperature (40ºC) and lower than 90% for 20ºC*
- *Maximum altitude 1000m*
- *Industrial EMC environment*

WIRING

- *Minimum cross sectional area for power wires 14 AWG*
- *Minimum cross sectional area for control and maneuver wires 18 AWG*
- *Color cable coding:*
- *Black: for rated voltage circuits.*
- *White or grey: for neutral or the grounded secondary circuit of transformers.*
- *Red: AC control circuits with a no rated voltage (for example: ungrounded secondary circuit of transformers)*
- *Blue: ungrounded CC current circuits with voltage.*
- *Yellow/green (or green): earth*
- *White with blue stripe: grounded DC current circuits.*
- *Orange: ungrounded control circuits or other wiring that remain energized when the circuit breaker is in the "off" position.*
- *White with orange stripe: grounded conductors that remains energized when the main circuit breaker is in the "off" position.*

STANDARDS

- *NFPA 70 – NEC ("National Electrical Code").*
- *UL 508A "INDUSTRIAL CONTROL PANELS"*
- *UL 891 "SWITCHBOARDS".*
- *NFPA 70E – "Standard for Electrical Safety in the Workplace".*
- *"IEEE Std 315-1975 (Reaffirmed 1993) Graphic Symbols for Electrical and Electronics Diagrams".*
- *UL467 (ANSI) "Grounding and Bonding Equipment".*

SIEMENS	GROUP		PRODUCT INFORMATION	INDEX
	IC	GAS	IC-G-B-56-321	A1
	POWER RATING		DATE 22/02/17	DEP. 2

GENSET:	**SGE-56HM**	**SPEED:**	**1200**
JACKET WATER TEMPERATURE(°F):	**194**	**FUEL TYPE:**	**SEWAGE GAS**
INTERCOOLER WATER TEMP(°F):	**131**		

SERVICE:			**CONTINUOUS**	COMPRESSION RATIO:	**11,9:1**
COOLING SYSTEM:			**TWO CIRCUITS**	REGULATION:	**Electronic**
			TWO STAGE IC / Oilcooler in main circuit	IGNITION TIMING:	**21º**
EXHAUST MANIFOLD TYPE:			**DRY**	MAX. BACK PRESSURE:	**18 ''H2O (450 mmH2O)**
EMISSIONS:					
	NO_x	g/bHPh	**1**	AMBIENT CONDITIONS ISO 3046/1:	
	CO	g/bHPh	**<2.2**	Atmospheric pressure (''Hg (kPa))=	**30 (100)**
	NMHC	g/bHPh	**<0.7**	Ambient temperature (°F (°C))=	**77 (25)**
	CH_4	g/bHPh	**<3**	Relative humidity (%)=	**30**
	CO_2	lb/h	**1627**		

POWER RATING (4)			**NOMINAL**	**PARTIAL LOADS**		
LOAD		%	**100%**	80%	60%	40%
MECHANICAL POWER	**(3, 4, 5)**	BHP (KWb)	**1395 (1040)**	1116 (832)	837 (624)	558 (416)
BMEP		psi (bar)	**270 (18.6)**	216 (14.9)	161 (11.1)	107 (7.4)
ELECTRICAL POWER (cosϕ 1)	**(9)**	kWe	**1011**	807	602	396
ELECTRICAL POWER (cosϕ 0,8)	**(9)**	kWe	**1000**	800	598	394
FUEL CONSUMPTION	**(1)**	BTU/bHP-hr (KW)	**5856 (2394)**	5978 (1955)	6189 (1518)	6586 (1077)
MECHANICAL EFFICIENCY		%	**43.4**	42.6	41.1	38.6
ELECTRICAL EFFICIENCY (cosϕ 1)	**(9)**	%	**42.2**	41.3	39.7	36.8
HEAT IN MAIN WATER CIRCUIT	**(1)**	BTU/min (KW)	**33320 (586)**	27130 (477)	21610 (380)	16890 (297)
HEAT IN SECONDARY WATER CIRCUIT	**(1)**	BTU/min (KW)	**3412 (60)**	2388 (42)	1820 (32)	1081 (19)
HEAT IN CHARGE COOLER	**(1)**	BTU/min (KW)	**3412 (60)**	2388 (42)	1820 (32)	1081 (19)
HEAT IN OIL COOLER	**(1)**	BTU/min (KW)	*******	***	***	***
HEAT IN EXHAUST GASES (25 ºC)	**(1)**	BTU/min (KW)	**36510 (642)**	31050 (546)	24570 (432)	17460 (307)
HEAT IN EXHAUST GASES (120ºC)	**(1)**	BTU/min (KW)	**27630 (486)**	23810 (419)	19080 (335)	13720 (241)
EXHAUST GAS TEMPERATURE	**(1)**	°F (°C)	**779 (415)**	811 (433)	842 (450)	876 (469)
HEAT TO RADIATION	**(1)**	BTU/min (KW)	**3753 (66)**	3298 (58)	2843 (50)	2161 (38)
CARBURETION SETTINGS (2)						
O_2 TO EXHAUST(DRY)(ONLY A REFERENCE)		%	**9.1**	9.0	8.8	8.5

MASS FLOWS						
INTAKE AIR FLOW	**(1)**	lb/h (Kg/h)	**10410 (4720)**	8450 (3830)	6400 (2900)	4340 (1970)
EXHAUST GAS FLOW (WET)	**(1)**	lb/h (Kg/h)	**11350 (5150)**	9220 (4180)	7010 (3180)	4760 (2160)

NOTES:

1. ALL VALUES ASUME LHV OF THE GAS. 100% LOAD TOLERANCES:
   FUEL CONSUMPTION +5%,
   COOLING CIRCUIT AND EXHAUST GASES ± 8%, RADIATION ±25%
   EXHAUST TEMPERATURE ±20°C, MASS FLOWS ± 10% (ALSO FOR CO2 FLOW IN EXHAUST).
2. THE ENGINE PERFORMANCE DATA, TIMING ADVANCE AND CARBURETION SETTINGS ARE VALID FOR A BIOGAS THAT FULFILS THE REQUIREMENTS DEFINED IN IC-G-D-30-001e AND IC-G-D-30-003e. HEAT BALANCE FOR A REFERENCE GAS: CH4 67%, CO2 33%
3. NET POWER, MECHANICAL PUMPS NOT INCLUDED.
4. POWERS ARE VALID FOR AMBIENT TEMP.=77ºF (25ºC) AND AN ALTITUDE OF =1640 ft (500 m). SEE OTHER CONDITIONS IN PI IC-G-B-00-005
5. OVERLOAD NOT ALLOWED. IT IS NOT RECOMMENDED TO OPERATE BELOW 40% LOAD DURING LONG TIME.
6. THE SPECIFICATIONS AND MATERIALS ARE SUBJECT TO CHANGE WITHOUT NOTIFICATION
7. A ENGINE WITH INLET OR OUTPUT RESTRICTION OVER PUBLISHED LIMITS, OR WITH INADEQUATE MAINTENANCE OR INSTALLATION CAN MODIFY POWER RATING DATA.
8. EMISSIONS ACCORDING TO D1 CYCLE IS 8178-4.
9. ALTERNATOR VOLTAGE 480 V
10. **ONLY IN PARALLEL TO THE GRID OPERATION**

SIEMENS	GROUP		PRODUCT INFORMATION	INDEX
	IC	GAS	IC-G-B-56-327	1
	POWER RATING		DATE 20/12/16	DEP. 2

GENSET:	**SGE-56HM**	**SPEED:**	**1800**
JACKET WATER TEMPERATURE(°F):	**194**	**FUEL TYPE:**	**SEWAGE GAS**
INTERCOOLER WATER TEMP(°F):	**131**		

SERVICE:			**CONTINUOUS**	COMPRESSION RATIO:		**11,9:1**
COOLING SYSTEM:			**TWO CIRCUITS**	REGULATION:		**Electronic**
			TWO STAGE IC / Oilcooler in main circuit	IGNITION TIMING:		**21º**
EXHAUST MANIFOLD TYPE:			**DRY**	MAX. BACK PRESSURE:		**18 ''H2O (450 mmH2O)**
EMISSIONS:						
	NO_x	g/bHPh	**1**	AMBIENT CONDITIONS ISO 3046/1:		
	CO	g/bHPh	**<2.2**		Atmospheric pressure (''Hg (kPa))=	**30 (100)**
	NMHC	g/bHPh	**<0.7**		Ambient temperature (°F (°C))=	**77 (25)**
	CH_4	g/bHPh	**<3**		Relative humidity (%)=	**30**
	CO_2	lb/h	**2164**			

POWER RATING (4)			NOMINAL	PARTIAL LOADS		
LOAD		%	**100%**	80%	60%	40%
MECHANICAL POWER	(3, 4, 5)	BHP (KWb)	**1810 (1350)**	1448 (1080)	1086 (810)	724 (540)
BMEP		psi (bar)	**234 (16.1)**	187 (12.9)	139 (9.6)	93 (6.4)
ELECTRICAL POWER (cosϕ 1)	(9)	kWe	**1305**	1043	778	513
ELECTRICAL POWER (cosϕ 0,8)	(9)	kWe	**1292**	1034	773	510
FUEL CONSUMPTION	(1)	BTU/bHP-hr (KW)	**6001 (3183)**	6134 (2603)	6372 (2028)	6853 (1454)
MECHANICAL EFFICIENCY		%	**42.4**	41.5	39.9	37.1
ELECTRICAL EFFICIENCY (cosϕ 1)	(9)	%	**41.0**	40.1	38.4	35.3
HEAT IN MAIN WATER CIRCUIT	(1)	BTU/min (KW)	**41230 (725)**	34580 (608)	28210 (496)	21900 (385)
HEAT IN SECONDARY WATER CIRCUIT	(1)	BTU/min (KW)	**4834 (85)**	3640 (64)	2559 (45)	1820 (32)
HEAT IN CHARGE COOLER	(1)	BTU/min (KW)	**4834 (85)**	3640 (64)	2559 (45)	1820 (32)
HEAT IN OIL COOLER	(1)	BTU/min (KW)	*****	***	***	***
HEAT IN EXHAUST GASES (25 ºC)	(1)	BTU/min (KW)	**53400 (939)**	44760 (787)	35660 (627)	25990 (457)
HEAT IN EXHAUST GASES (120ºC)	(1)	BTU/min (KW)	**41930 (737)**	35470 (624)	28580 (503)	21070 (370)
EXHAUST GAS TEMPERATURE	(1)	°F (°C)	**874 (468)**	900 (482)	937 (503)	982 (528)
HEAT TO RADIATION	(1)	BTU/min (KW)	**4777 (84)**	3640 (64)	2843 (50)	2275 (40)
CARBURETION SETTINGS (2)						
O_2 TO EXHAUST(DRY)(ONLY A REFERENCE)		%	**8.6**	8.5	8.2	8.1
MASS FLOWS						
INTAKE AIR FLOW	(1)	lb/h (Kg/h)	**13340 (6050)**	10850 (4920)	8240 (3740)	5680 (2580)
EXHAUST GAS FLOW (WET)	(1)	lb/h (Kg/h)	**14600 (6620)**	11880 (5390)	9050 (4100)	6260 (2840)

NOTES:

1. ALL VALUES ASUME LHV OF THE GAS. 100% LOAD TOLERANCES:
   FUEL CONSUMPTION +5%,
   COOLING CIRCUIT AND EXHAUST GASES ± 8%, RADIATION ±25%
   EXHAUST TEMPERATURE ±20°C, MASS FLOWS ± 10% (ALSO FOR CO2 FLOW IN EXHAUST).
2. THE ENGINE PERFORMANCE DATA, TIMING ADVANCE AND CARBURETION SETTINGS ARE VALID FOR A BIOGAS THAT FULFILS THE REQUIREMENTS DEFINED IN IC-G-D-30-001e AND IC-G-D-30-003e. HEAT BALANCE FOR A REFERENCE GAS: CH4 67%, CO2 33%
3. NET POWER, MECHANICAL PUMPS NOT INCLUDED.
4. POWERS ARE VALID FOR AMBIENT TEMP.=77ºF (25ºC) AND AN ALTITUDE OF =1640 ft (500 m). SEE OTHER CONDITIONS IN PI IC-G-B-00-005
5. OVERLOAD NOT ALLOWED. IT IS NOT RECOMMENDED TO OPERATE BELOW 40% LOAD DURING LONG TIME.
6. THE SPECIFICATIONS AND MATERIALS ARE SUBJECT TO CHANGE WITHOUT NOTIFICATION
7. A ENGINE WITH INLET OR OUTPUT RESTRICTION OVER PUBLISHED LIMITS, OR WITH INADEQUATE MAINTENANCE OR INSTALLATION CAN MODIFY POWER RATING DATA.
8. EMISSIONS ACCORDING TO D1 CYCLE IS 8178-4.
9. ALTERNATOR VOLTAGE 480 V
10. **ONLY IN PARALLEL TO THE GRID OPERATION**

MODULE	**Generator Set Control and Power Panel**	
	Engine:	**SGE-SL, SGE-SM, SGE-HM**
	Range:	**18, 24, 36, 48, 56**
	Speed:	**1200, 1500 & 1800**
	Fuel:	**N/A**

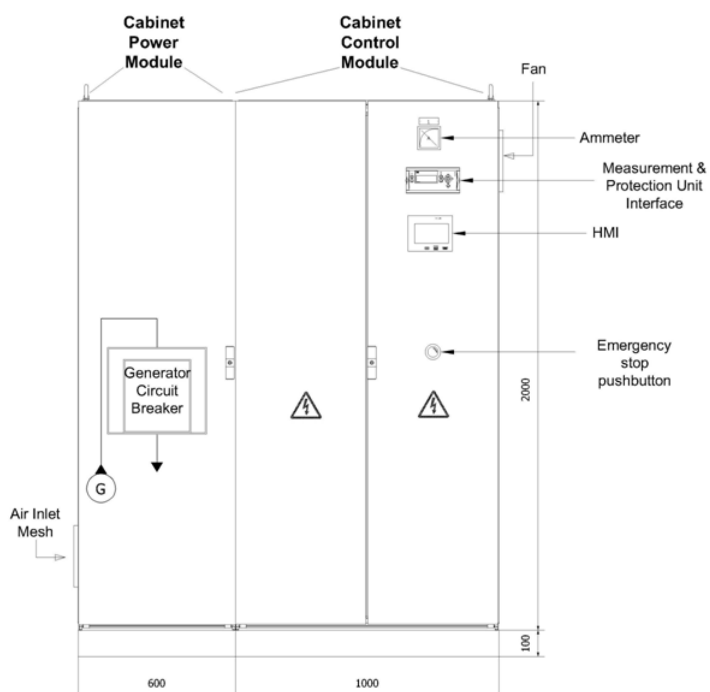
As Feb 2014
To be verified at point of order

➢ *Description*

The Siemens generator set control panel complements the engine and alternator supply to provide integrated, tested and reliable control and power switching.

The control system is provided in two cabinets – a control cabinet and a power cabinet, these can be supplied assembled or as separate parts. The cabinet construction is modular, made from powder coated steel and supplied as two floor standing enclosures. The nominal dimensions will be height 78.7”, depth 23.6” control section width 39.3”, power section width 23.6”. (Optional 4” plinth is available)

The physical appearance of the cabinet is shown in the figures below:



➢ ***Power cabinet: -***

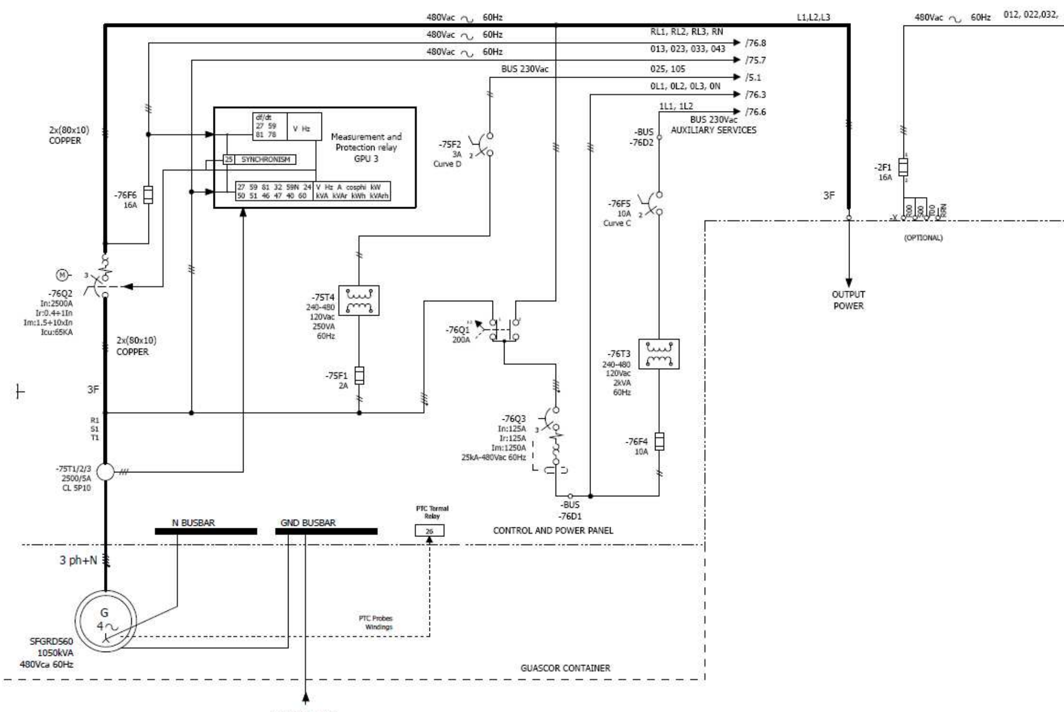
The power cabinet contains the motor actuated breaker to connect the alternator to the load, along with voltage and current monitoring for generator set control protection and metering.
Within the cabinet is the chassis mounted breaker and copper busbar for alternator and customer connections – the busbars are insulated and color coded for safety and identification, the bars are also pre-drilled for ease of connection.

Cable entry to the cabinet is through the base for the power cabling and for control wiring. The cabinet is equipped with an anti-condensation heater and a filtered ventilation opening.

Scope to include:

- *Enclosure, coated steel with single opening door, lifting eyes, connections through the base*
- *Motor actuated spring charge breaker rated for the generator set duty, 3 pole with integral overcurrent protection, under-voltage release and status indication.*
- *Current transformers rated to the generator set duty, protection class 5P10, located on the alternator side of the breaker, to measure the generator current (gross)*
- *Copper bus bar – rated for the operating duty and alternator fault current. Insulated and color identified.*
- *Voltage transformers – step down to provide monitoring and control voltage level for the control side of the panel, voltage transformers are provided on both the load and alternator side of the breaker.*
- *Auxiliary power take off – a supply from the load side of the breaker to an isolator switch, to be used to supply the auxiliary system of the control panel and generator set package.*

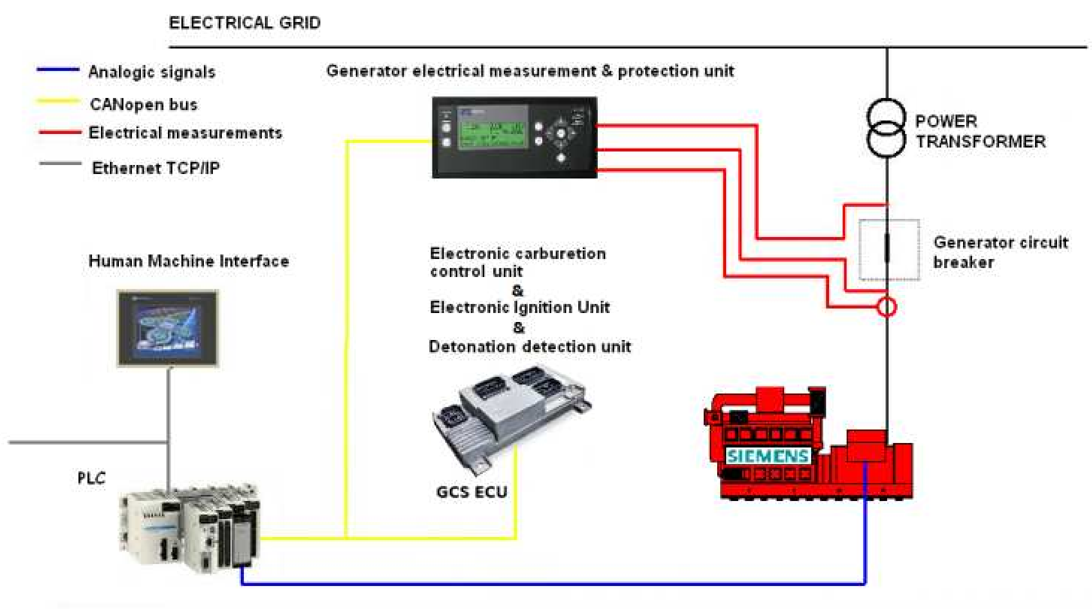
Simplified one-line diagram – for information only



➢ *Control Cabinet*

The control cabinet contains the integral parts of the generator set control system, supplied as a single two door enclosure designed to integrate and sit along-side the power panel – but can but mounted remote from the power panel with an option wire harness.
The generator set will be supplied pre-wired to a junction box, this junction box will then wire to the control panel to provide communications with the generator set.

- *The key parts of the control system are:*
  - *PLC and touchscreen HMI*
  - *Generator control module – for protection, measurement and synchronization*
  - *Engine Control unit GCS-E (engine mounted)*
  - *Ancillary systems power and control*
  - *Battery charging*
  - *Communications interface*
- *The architecture of the control system is shown in the sketch below:*



➢ *Control cabinet functionality*

Power panel control

- *Generator side voltage measurement: Direct taps or step-down transformers provide voltage sensing of the generator voltage for control and monitoring*
- *Load side voltage measurement: Direct taps or step-down transformers provide voltage sensing of the mains (utility) voltage for control, synchronization and protection*
- *Generator current measurement: Bus-bar mounted CT's between the generator and the breaker provide current measurement of the generator (gross), used for power measurement and protection*
- *Generator circuit breaker control: Open and Close orders of the generator sync breaker*
  The circuit breaker has the following elements:
  - *Spring actuated motor operator*

  - *Remote closing release*
  - *Under-voltage release*
  - *Volt-free contacts for indication of status (open/closed) and trips*
  - *The voltage for control will be 120 VAC*
- *Depending on the application two configurations for breaker closing are possible:*
  - *Direct closing - without synchronization ("Black start"). Load voltage sensing must show no volts*
  - *Closing with synchronization ("start with coupling to the mains")*
- *The under-voltage release coil is fuse protected; it will trip the breaker in the following events:*
  - *Open signal from the PLC.*
  - *Emergency stop.*
  - *Open signal from the generator electrical protection unit in the event of a protection trip.*

Control system power supply

- *The control system is supplied with 24 VDC from a rectifier and 2 battery systems, the main starting batteries and a set of panel auxiliary batteries. The main starter batteries are placed on the generator set base-frame – primary use engine starting secondary use dc power for control system.*
- *The panel auxiliary batteries are placed inside the cabinet. They provide dc and backup power for a series of critical services (power to the PLC and multifunction protection unit and maintain event and data logging), maintaining autonomy in absence of the mains power and during engine cranking to avoid main battery voltage dip. They are isolated from the main batteries by a diode bridge to avoid reverse discharge.*
- *The cabinet has an electronic rectifier/battery charger with an output of 24 VDC and 20A. The power supply to feed this equipment will be 3 phase taken from the auxiliary service feed.*
- *The main circuits supplied by the 24VDC rectifier/batteries system are:*
  - *PLC & HMI*
  - *Under-voltage relay to monitor the 24 Vdc voltage supply*
  - *Generator protection and measurement unit*
  - *Engine control unit GCS-E*
  - *Emergency stop relay*
  - *Cranking motor.*
  - *Gas ramp.*
  - *Pre-lube pump.*

Emergency Stop

- *The generator set is equipped with 2 emergency stop push-buttons: one alongside the engine and the other on the cabinet door. Pushing either of them will activate the safety relay.*
- *The safety relay will safely perform the following functions when activated:*
- *It will open the generator circuit breaker*
- *It will cut off the fuel supply to the engine, stopping it.*
- *It will stop the pre-lube pump (both in manual mode and in automatic mode).*
- *Give an indication to the PLC for signal recognition (NC contact).*
- *The emergency push-button and the safety relay when activated will require manual reset*

Engine Control Unit "GCS-E"

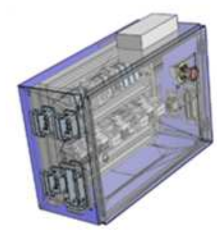
- *GCS-E Engine control unit: The GCS-E is an engine ECU that provides the complete management for safe efficient operation of the engine through integration of the following systems:*
  - *Engine ignition system*

- *Engine carburation / emission control system*
- *Engine speed and load control*
- *Detonation protection system*
- *Engine auxiliary control, start/stop, pre-heat, pre-lube*
- *Engine parameter monitoring*
- *Engine protection and alarms*

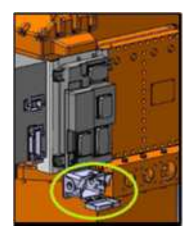
– *The GCS-E also provides customer interfacing through Modbus TCP-IP, CAN J1939 and CAN open*

– *The GCS-E system comprises an ECU, power relay box, harness, customer interface and engine sensors / actuators. All components including ECU and power relay box are engine mounted, the system is completely wired and tested prior to supply.*

– *The GCS-E – ECU: is a single module that is the brain of the control; it integrates control for ignition, carburation, speed and load control, detonation protection, ancillary devices and protection. System configuration is through a single user interface and multiple interface options are available for communication and integration with third party generation or system controllers.*



– *The GCS-E - Power Relay Box: provides the interface between the ECU and the engine ancillaries. The power box requires a 24vdc and a 480v 3 phase AC power supply (by customer) power is then distributed within the box to the ECU as well as the relays and contactors required to operate the included ancillaries (Pre-lube pump, Jacket water heater, starter motor, oil heaters etc). The power box is the location of the engine emergency stop push button.*



– *GCS-e - Harness + Customer Interface connector: The engine is supplied pre-wired through a dedicated wire harness for all included sensors, actuators and ancillaries. Customer interfacing is through a single location using a ruggedized connector (customer interfacing includes – communications, measured power, demand start/stop). After manufacture the engine is tested with the included electrical harness, ancillary devices and ECU installed, ensuring reliable operation and simplified installation and commissioning.*

Generator protection unit

– *The generator protection unit is a multifunction control device that provides protection of the alternator, measurement of the electrical output and synchronization functions. A summary of the function provided is provided below:*

– *Generator protection functions*
- *Under and over-voltage (ANSI 27/59)*
- *Under and over-frequency (ANSI 81m/81M)*
- *Mechanical overload (ANSI 32)*
- *Reverse power (ANSI 32)*
- *Overcurrent (2 levels) (ANSI 51)*
- *Fast Overcurrent (<42 ms) (ANSI 50/51)*

    - *High overcurrent (<350%) (ANSI 50)*
    - *Current unbalance (ANSI 46)*
    - *Voltage asymmetry (ANSI 47)*
    - *Excitation loss from high reactive power consumption*
    - *Over excitation from high reactive power export (ANSI 40)*
- *The measurements carried out and displayed by the unit are:*
    - *Voltage (3 phases)*
    - *Current (3 phases)*
    - *Active power (kW)*
    - *Reactive power (kVar)*
    - *Power factor (cos phi)*
    - *Frequency (f)*
    - *Energy supplied by the generator (kWh)*
- *Generator to plant connecting busbar supervision*
- *Synchronizing*
- *CAN OPEN communication with PLC*

Cooling system control

- *The control system is pre-configured to prove control of the cooling system – (subject to motor size details being provided) Two options are available*
- *Option A - Cooling through a simplified tower. To include the following control:*
    - *Main cooling circuit pump*
    - *Secondary cooling circuit pump*
    - *Cooling tower pump*
    - *Cooling tower fan*
- *Option B – Cooling through air blast coolers. To include the following control:*
    - *Main cooling circuit pump*
    - *Secondary cooling circuit pump*
    - *Air water cooler fans 1 and 2 (1st cooling stage)*
    - *Air water cooler fans 3 and 4 (2nd cooling stage)*
    - *Air water cooler fans 5 and 6 (3rd cooling stage)*
- *The control system will provide thermostatic control of the main and secondary circuit water temperatures based upon the main cooling circuit temperature and the air intake temperature.*
- *The HMI provides mode selection for each circuit (automatic, manual or disabled) and an auxiliary services configuration menu.*
- *In manual mode the respective cooling system will be powered and the motor will start. With the selector in disabled all systems will remain disconnected. With the selector in the automatic mode, the motors will work when the conditions for an automatic start are fulfilled.*

Each motor will be protected by means of a thermal magnetic motor circuit breaker with the appropriate rating. The PLC will receive signals to confirm the operation of the service and a trip of the protection. Both states will be displayed in the HMI. An alarm will be display in the HMI if the protection trips activate or if there is no confirmation of a working condition when the working order is active.

Customer connections

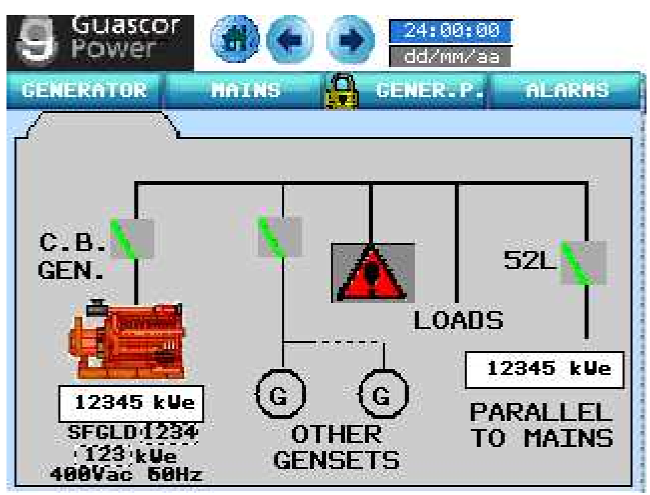
- *The control system provides volt free contacts (VFC) of genset information, available for external connection to other plant equipment. The signals are as follows:*
    - *Genset working*
    - *Genset horn beeping*
    - *Genset general alarm*
    - *Genset circuit breaker status*
    - *Genset connected to the mains*

AVR control

- *The control system provides control of the alternator AVR to maintain correct voltage regulation at synchronization and during island operation, provide voltage matching during synchronization and power factor control during parallel operation.*
- *The AVR parameterization and monitoring is performed through the HMI, alarm states from the AVR and displayed on the HMI.*

PLC and HMI

- *The control system is built around an industrial based PLC with connected HMI. The PLC is programmed to provide reliable and safe operation of the generator set under all operating condition. The control system is configured through parameterization during commissioning and should not require further adjustment between service intervals. The HMI is a color touchscreen graphic terminal installed on the cabinet door (optionally it can be supplied to terminals for remote mounting.*
- *The PLC communicates using CANopen with the modules of the control system (GCS-E, GPU) providing fast reliable communication. The PLC also has an Ethernet TCP/IP port, which provides the communication with similar gensets to share load in islanding operation. In addition the TCP/IP communication port also provides the options for:*
    - *Remote warnings (by GSM or similar, OPTIONAL)*
    - *Data map export to a SCADA (OPTIONAL)*
- *The screen image below is a sample from the base HMI showing the one line operational view:*



Detonation Protection

Recommended for all generator sets

- *The detonation detection system is a module within the GCS-E.*
- *The detonation detection system provides protection against detonation in the cylinders of the engine – an undesirable and detrimental operating condition. The system consists of 2 parts:*
- *The GCS-E control unit processes the information from the sensors and sets the correction action required to eliminate detonation, then reestablish the original values when possible.*
- *Sensors - piezoelectric sensors that provide the vibration signals from the cylinder walls to the GCS-E control unit.*
- *The GCS-E utilizes CANopen communications to transmit all of the relevant information to the PLC (detonation status, load reduction, high priority alarm and ignition timing modification).*
- *The HMI provides parameterization of the system and display of operating data and alarm conditions.*

Options:

- *Other options are available: please contact local distributor or Dresser-Rand for details:*
- *Multi set load sharing and island management*
- *Mains (utility) circuit breaker control*
- *Engine- electric pre-heating*
- *Energy metering*
- *Cylinder exhaust temperatures*
- *Alternator winding and bearing temperature monitoring*
- *Gas pressure and booster control*

Enclosure General Characteristics

- *Interior lighting with door microswitch*
- *120Vac/6A utility socket*
- *Fan Ventilation (optional air conditioning unit)*
- *All ancillaries protected against overcurrent and short circuit.*
- *Auxiliary services feeder with residual current protection*
- *The relays for control purposes will include lockable test button and mechanical interlock.*
- *Protection degree IP54*
- *Cable gland plate for entry of cables and non-protected active parts IP20*
- *Fan and vent grille: IP54*
- *Steel sheet thickness: 2mm.*
- *Epoxy polyester powder coating finish with 50 microns thickness and painted with RAL 7035.*
- *Enclosure labels engraved and fixed with rivets or screws*

Storage Specification

- *Protection rating* *IP 54 (5: Dust protected and 4 Water splashing against the enclosure from any direction shall have no harmful effect).*
  Cabinet should not be subject to direct sunlight.
- *Resistance against impacts* *IK 8 (Resistance against impacts with an energy up to 5 JOULE 1,7Kg - 29,5cm)*
- *Storage Temperature* *-20C to +60C (-4F to +140F)*
- *Relative Humidity* *85% w/o condensation*

- *Air purity (dust)* *≤ 0,1mg/ m3 (10-7 oz/ft³) (non-conductive levels)*
- *Corrosive gases* *Free of corrosive gases*
- *CAUTION*
- *After a longer storage time the first operation that should be carried out before the start up will be:*
    - *1) Supply the AUXILIARY SERVICES to activate the battery charger and charge the PLC batteries to ensure its operation.*
    - *2) After connect the cabinet with the genset, it shoud be carry out a starting order for the pre-lube pump and the preheating systems before the genset starting.*

WORKING CONDITIONS

- *Indoor use only*
- *Maximum ambient temperature: 40ºC*
- *Maximum continuous temperature over a 24h period: 35ºC.*
- *Minimum ambient temperature: -5ºC*
- *Industrial environment*
- *Pollution degree: 2*
- *Relative humidity lower than 50% for the maximum allowed temperature (40ºC) and lower than 90% for 20ºC*
- *Maximum altitude 1000m*
- *Industrial EMC environment*

WIRING

- *Minimum cross sectional area for power wires 14 AWG*
- *Minimum cross sectional area for control and maneuver wires 18 AWG*
- *Color cable coding:*
- *Black: for rated voltage circuits.*
- *White or grey: for neutral or the grounded secondary circuit of transformers.*
- *Red: AC control circuits with a no rated voltage (for example: ungrounded secondary circuit of transformers)*
- *Blue: ungrounded CC current circuits with voltage.*
- *Yellow/green (or green): earth*
- *White with blue stripe: grounded DC current circuits.*
- *Orange: ungrounded control circuits or other wiring that remain energized when the circuit breaker is in the "off" position.*
- *White with orange stripe: grounded conductors that remains energized when the main circuit breaker is in the "off" position.*

STANDARDS

- *NFPA 70 – NEC ("National Electrical Code").*
- *UL 508A "INDUSTRIAL CONTROL PANELS"*
- *UL 891 "SWITCHBOARDS".*
- *NFPA 70E – "Standard for Electrical Safety in the Workplace".*
- *"IEEE Std 315-1975 (Reaffirmed 1993) Graphic Symbols for Electrical and Electronics Diagrams".*
- *UL467 (ANSI) "Grounding and Bonding Equipment".*

SIEMENS	GROUP	GAS	PRODUCT INFORMATION	INDEX
	IC		IC-G-B-42-059	1
	POWER RATING		DATE 20/12/16	DEP. 2

GENSET:	**SGE-42HM**	**SPEED:**	**1800**
JACKET WATER TEMPERATURE(°F):	**194**	**FUEL TYPE:**	**SEWAGE GAS**
INTERCOOLER WATER TEMP(°F):	**131**		

SERVICE:	**CONTINUOUS**	COMPRESSION RATIO:	**11,9:1**
COOLING SYSTEM:	**TWO CIRCUITS**	REGULATION:	**Electronic**
	TWO STAGE IC / Oilcooler in main circuit	IGNITION TIMING:	**21º**
EXHAUST MANIFOLD TYPE:	**DRY**	MAX. BACK PRESSURE:	**18 "H2O (450 mmH2O)**
EMISSIONS:			
	NO_x g/bHPh **1**	AMBIENT CONDITIONS ISO 3046/1:	
	CO g/bHPh **<2.2**	Atmospheric pressure ("Hg (kPa))=	**30 (100)**
	NMHC g/bHPh **<0.7**	Ambient temperature (°F (°C))=	**77 (25)**
	CH_4 g/bHPh **<3**	Relative humidity (%)=	**30**
	CO_2 lb/h **1669**		

POWER RATING (4)			**NOMINAL**	**PARTIAL LOADS**		
LOAD		%	**100%**	80%	60%	40%
MECHANICAL POWER	**(3, 4, 5)**	BHP (KWb)	**1395 (1040)**	1116 (832)	837 (624)	558 (416)
BMEP		psi (bar)	**239 (16.5)**	192 (13.2)	144 (9.9)	96 (6.6)
ELECTRICAL POWER (cosφ 1)	**(9)**	kWe	**1007**	805	601	395
ELECTRICAL POWER (cosφ 0,8)	**(9)**	kWe	**997**	798	597	393
FUEL CONSUMPTION	**(1)**	BTU/bHP-hr (KW)	**6005 (2455)**	6189 (2024)	6409 (1572)	6855 (1121)
MECHANICAL EFFICIENCY		%	**42.4**	41.1	39.7	37.1
ELECTRICAL EFFICIENCY (cosφ 1)	**(9)**	%	**41.0**	39.8	38.2	35.2
HEAT IN MAIN WATER CIRCUIT	**(1)**	BTU/min (KW)	**32640 (574)**	27180 (478)	21610 (380)	16440 (289)
HEAT IN SECONDARY WATER CIRCUIT	**(1)**	BTU/min (KW)	**3242 (57)**	2616 (46)	1877 (33)	1308 (23)
HEAT IN CHARGE COOLER	**(1)**	BTU/min (KW)	**3242 (57)**	2616 (46)	1877 (33)	1308 (23)
HEAT IN OIL COOLER	**(1)**	BTU/min (KW)	*****	***	***	***
HEAT IN EXHAUST GASES (25 ºC)	**(1)**	BTU/min (KW)	**40600 (714)**	34690 (610)	27810 (489)	20360 (358)
HEAT IN EXHAUST GASES (120ºC)	**(1)**	BTU/min (KW)	**31790 (559)**	27500 (483)	22320 (393)	16620 (292)
EXHAUST GAS TEMPERATURE	**(1)**	°F (°C)	**865 (463)**	903 (484)	946 (508)	1004 (540)
HEAT TO RADIATION	**(1)**	BTU/min (KW)	**3981 (70)**	3298 (58)	2616 (46)	1990 (35)
CARBURETION SETTINGS (2)						
O_2 TO EXHAUST(DRY)(ONLY A REFERENCE)		%	**8.6**	8.5	8.2	7.9
MASS FLOWS						
INTAKE AIR FLOW	**(1)**	lb/h (Kg/h)	**10260 (4650)**	8350 (3790)	6350 (2880)	4350 (1980)
EXHAUST GAS FLOW (WET)	**(1)**	lb/h (Kg/h)	**11230 (5100)**	9160 (4150)	6970 (3160)	4800 (2180)

NOTES:

1. ALL VALUES ASUME LHV OF THE GAS. 100% LOAD TOLERANCES:
   FUEL CONSUMPTION +5%,
   COOLING CIRCUIT AND EXHAUST GASES ± 8%, RADIATION ±25%
   EXHAUST TEMPERATURE ±20°C, MASS FLOWS ± 10% (ALSO FOR CO2 FLOW IN EXHAUST).
2. THE ENGINE PERFORMANCE DATA, TIMING ADVANCE AND CARBURETION SETTINGS ARE VALID FOR A BIOGAS THAT FULFILS THE REQUIREMENTS DEFINED IN IC-G-D-30-001e AND IC-G-D-30-003e. HEAT BALANCE FOR A REFERENCE GAS: CH4 67%, CO2 33%
3. NET POWER, MECHANICAL PUMPS NOT INCLUDED.
4. POWERS ARE VALID FOR AMBIENT TEMP.=77ºF (25ºC) AND AN ALTITUDE OF =1640 ft (500 m). SEE OTHER CONDITIONS IN PI IC-G-B-00-005
5. OVERLOAD NOT ALLOWED. IT IS NOT RECOMMENDED TO OPERATE BELOW 40% LOAD DURING LONG TIME.
6. THE SPECIFICATIONS AND MATERIALS ARE SUBJECT TO CHANGE WITHOUT NOTIFICATION
7. A ENGINE WITH INLET OR OUTPUT RESTRICTION OVER PUBLISHED LIMITS, OR WITH INADEQUATE MAINTENANCE OR INSTALLATION CAN MODIFY POWER RATING DATA.
8. EMISSIONS ACCORDING TO D1 CYCLE IS 8178-4.
9. ALTERNATOR VOLTAGE 480 V
10. **ONLY IN PARALLEL TO THE GRID OPERATION**

Microturbines Vendor Quotes

Regatta Solutions
Smart Power

April 26th, 2017

Alison Nojima
Brown and Cladwell
11929 White Rock Road # 200
Rancho Cordova, Ca 95670

RE: Roseville Biogas CHP System

Dear Alison,

Per your request for pricing, see the following tables for equipment pricing. Please note that this pricing is based on Capstone 2017 pricing and is subject to change if project is extended beyond this year. The pricing does not include shipping cost.

Equipment Pricing				
Description	Part Number	Price	Qty	Ext Price
C1000 LANDFILL GAS, GC, INDPKG, UL	1000S-AG4-BU00	$1,232,947.06	1	$1,232,947.06
Heat Recovery Module	HRSR-260B24.5SSP	$149,388.24	1	$149,388.24
EVOLUTION System - HRM Control	ECS-ETH-4-3-40	$30,600.00	1	$30,600.00
				$1,412,935.29

Table 1: Equipment Pricing

Services Pricing			
Description	Price	Qty	Ext Price
Sequence of Operation - Coordination	$150.00	80	$12,000.00
Commissioning	$245.00	56	$13,720.00
			$13,720.00

Table 2: Services Pricing

Maintenance Pricing			
Description	Price	Qty	Ext Price
Annual FPP Pricing, Option D, Single Unit	$141,572.40	1	$141,572.40
Annual Reporting Fees	$1,200.00	1	$1,200.00
Annual Maintenance Fees	$1,200.00	1	$1,200.00
			$143,972.40

Table 3: Maintenance Pricing

Evolution Control System Price Break Out			
Description	Price	Qty	Ext Price
Evolution Control System	$22,600.00	1	$22,600.00
HRM and Pump Control Programming	$200.00	40	$8,000.00
			$30,600.00

Table 4: Control System Breakout Pricing

- The following Quotation is provided for budgetary purposes. A complete equipment list and pricing for permitting and construction services may be determined once engineering drawings are completed with city/county approval.

- Quotation DOES NOT include additional Inlet or Exhaust Sound Attenuation, Construction Material for Mounting/Connection/Integration to Existing Facilities.

- Quotation DOES NOT include SGIP or Other Incentive Application Submittal/Deposit Fees/Rebates, Electrical Interconnect Application Submittal/Fees/Telemetry, Air Permit Application Submittal/Fees, Emissions Source Testing, Engineering or Engineering Drawings, City Plan Check/Permit Fees, Construction Services, Controls Integration, Internet Connection, Monthly Internet Service Provider Fees, Program Management, or other Services not specifically identified on this Quotation.

- All equipment is to be installed in accordance with Manufacturer's Specifications

- Installation Checklist (410026E) must be completed by the contractor and submitted to Regatta Solutions for approval prior to Commissioning.

- Contact Regatta Solutions at 877-639-9922 to schedule Service Technician two weeks prior to desired Commissioning date.

- Additional Terms and Conditions in accordance with Regatta Solutions, Inc. Equipment Sales Agreement attached to this quotation.

Cal Microturbine, Inc.
2537D Pacific Coast Highway #146
Torrance, CA 90505
(424) 256-8225
www.calmicroturbine.com

QUOTE

ADDRESS
Brown and Caldwell
201 N. Civic Drive Ste #300
Walnut Creek, CA 94596

QUOTE # 1059
DATE 08/18/2017
EXPIRATION DATE 12/31/2017

CATALOG NUMBER	PRODUCT DESCRIPTION	QTY	RATE	AMOUNT
800S-BG4-BU00-A000	C800S,DIGSTR GAS,GC,UL,C1KC	1	1,079,200.00	1,079,200.00
CLC Programming	Capstone Applications Support	20	300.00	6,000.00
Commissioning	5 days on site, 2 technicians	80	300.00	24,000.00
533074-100	EXHAUST BACKFLOW VALVE, 12 INCH	4	2,240.00	8,960.00
EXHAUST MANIFOLD	C800 MANIFOLD 4 PORTS 28" OUTLET ANGLED CARBON STEEL	1	17,728.00	17,728.00
HRM	HRSR-260H24.5SSP INCLFull Port Exhaust Gas Bypass, Condensate Drain, Stainless Inner Wall, Single Fintube Row Design	1	146,476.00	146,476.00
C800 HP G GC UL/CE 8	Factory Protection Plan D - 10 Years (Annual Price)	1	93,662.00	93,662.00

20% deposit is required upon receipt of signed Price Quote from the Client.

All shipping costs are the responsibility of the Client.

This Price Quote and all orders associated herewith are subject to the Company’s Standard Terms and Conditions of Sale as may be attached hereto or issued by the Company.

SUBTOTAL	1,376,026.00
TAX (7.25%)	90,796.39
TOTAL	**$1,466,822.39**

Accepted By

Accepted Date

Vehicle Fueling Vendor Quotes

J-W, FIBA and ANGI budgetary CNG Equipment Pricing

Item	QTY	Unit Price	Total Price	Description
Gas Dryer	1	$ 59,830.00	$ 59,830.00	ANGI 24" Gas Dryer, Sized for 777 SCM @ 100 psig, 3" piping, 214 hours between regens, 10.00 MMSCF capacity.
JW Powerfill	2	$ 398,729.10	$ 797,458.20	150HP J-W Powerfill, 2 or 4 stage, 390 scfm @ 65 psig inlet pressure, includes compressor connection materials
~~ANGI NG300E Compressor (C2)~~	0	$ -	$ -	~~300 HP NG300E Compressor, 2 stage, 1804 scfm @ 725 psig, 60F gas temperature, includes compressor connection materials~~
~~Heater Panel~~	0	$ -	$ -	~~Heater panel, approx 85 kW heater, regulates gas from storage bank, Assuming gas temperature of 75F @ 3000 psig IN, 40F @ 725 psig OUT, includes therm~~
VFDs and Motor Starter Panel	1	$ 51,723.00	$ 51,723.00	150 HP VFDs and starter panel, includes gearing for related CNG equipment
Priority Valve Panel	1	$ 35,175.00	$ 35,175.00	3-Bank priority panel, High, Mid, and Low banks. Controlled by onboard Horner PLC and Master Control Panel
CNG Dispenser	4	$ 42,750.00	$ 171,000.00	ANGI Series II dispenser, Single Hose, CT5000 nozzle, based on 3-bank sequencing, includes vibration switch and pit frame
Master Control Panel	1	$ 100,000.00	$ 100,000.00	Allen Bradley Master Control Panel, controls operations of compressors and priority filling
~~CP-400~~	0	$ -	$ -	~~CP-400 Communications Panel, Provides fault annuciation through email or SMS, ethernet communication required.~~
Storage Assembly from FIBA	14	$ 30,000.00	$ 420,000.00	FIBA ASME CNG Storage Vessels, includes valving, reliefs, and vent stack
Estimated per truck freight TBD	7	$ 11,500.00	$ 80,500.00	Estimated freight to TBD
Start-up and commissioning	1	$ 75,000.00	$ 75,000.00	Includes technician(s) on-site to perform start-up.
		Total:	$ 1,790,686	

Date: June 2017

Attachment B: Model Outputs

		Risk adjustments (+/- percent):	
Year of analysis	2020	**Benefits**	0%
Escalation rate	2.00%	**Capital costs**	
Discount rate	3.00%	**Running costs**	

Alternative 1
Status Quo
Life Cycle Alternative Cost Analysis ($)

Expressed in 2020 dollars, unescalated -- dollars

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capital Outlays																				
Engine replacement + Siloxane Removal								8,220,000												
Pump and blower replacement																500,000				
Total capital outlays	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**8,220,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**500,000**	**0**	**0**	**0**	**0**
Benefits:																				
Power Savings	(190,592)	(190,592)	(190,592)	(190,592)	(190,592)	(190,592)	(190,592)	(269,871)	(269,871)	(269,871)	(269,871)	(269,871)	(269,871)	(269,871)	(269,871)	(269,871)	(269,871)	(269,871)	(269,871)	(269,871)
Engine Salvage																				(2,877,000)
RIN Revenue																				
CNG Sale																				
Peak shaving/curtailment credit	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)
Total benefits	**(240,512)**	**(240,512)**	**(240,512)**	**(240,512)**	**(240,512)**	**(240,512)**	**(240,512)**	**(319,791)**	**(319,791)**	**(319,791)**	**(319,791)**	**(319,791)**	**(319,791)**	**(319,791)**	**(319,791)**	**(319,791)**	**(319,791)**	**(319,791)**	**(319,791)**	**(3,196,791)**
Annual Running Costs:																				
Engine O&M	105,458	105,458	105,458	105,458	105,458	105,458	105,458	105,458	[illegible]	458	105,458	105,458	105,458	105,458	105,458	105,458	105,458	105,458	105,458	105,458
Natural Gas	10,431	10,431	10,431	10,431	10,431	10,431	10,431	10,431	[illegible]	431	10,431	10,431	10,431	10,431	10,431	10,431	10,431	10,431	10,431	10,431
Biogas Upgrading O&M																				
Vehicle Fueling O&M																				
Additional Staffing																				
Gas Transmission Injection																				
Parasitic Electrical																				
Siloxane Removal Media/Landfill								29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000
Total running costs	**115,889**	**115,889**	**115,889**	**115,889**	**115,889**	**115,889**	**115,889**	**144,889**	**144,889**	**144,889**										
Net Benefit/(cost)	**(124,623)**	**(124,623)**	**(124,623)**	**(124,623)**	**(124,623)**	**(124,623)**	**(124,623)**	**8,045,098**	**(174,902)**	**(174,902)**										

Windows User:
assume same O&M even though engine output higher since function of run hours

Expressed in escalated dollars with sensitivity adjustments

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capital Outlays																				
Engine replacement + Siloxane Removal	0	0	0	0	0	0	0	9,442,196	0	0	0	0	0	0	0	0	0	0	0	0
Pump and blower replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	672,934	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**9,442,196**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**672,934**	**0**	**0**	**0**	**0**
Benefits:																				
Power Savings	(190,592)	(194,404)	(198,292)	(202,258)	(206,303)	(210,429)	(214,637)	(309,997)	(316,197)	(322,521)	(328,971)	(335,550)	(342,261)	(349,107)	(356,089)	(363,211)	(370,475)	(377,884)	(385,442)	(393,151)
Engine Salvage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(4,191,246)
RIN Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CNG Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak shaving/curtailment credit	(49,920)	(50,918)	(51,937)	(52,976)	(54,035)	(55,116)	(56,218)	(57,342)	(58,489)	(59,659)	(60,852)	(62,069)	(63,311)	(64,577)	(65,868)	(67,186)	(68,529)	(69,900)	(71,298)	(72,724)
Total benefits	**(240,512)**	**(245,322)**	**(250,228)**	**(255,233)**	**(260,338)**	**(265,544)**	**(270,855)**	**(367,339)**	**(374,686)**	**(382,180)**	**(389,823)**	**(397,620)**	**(405,572)**	**(413,684)**	**(421,957)**	**(430,396)**	**(439,004)**	**(447,784)**	**(456,740)**	**(4,657,121)**
Discounted Benefits (in 2020$)	**(240,512)**	**(238,177)**	**(235,864)**	**(233,574)**	**(231,307)**	**(229,061)**	**(226,837)**	**(298,680)**	**(295,781)**	**(292,909)**	**(290,065)**	**(287,249)**	**(284,460)**	**(281,698)**	**(278,963)**	**(276,255)**	**(273,573)**	**(270,917)**	**(268,287)**	**(2,655,891)**
Annual Running Costs:																				
Engine O&M	105,458	107,567	109,718	111,913	114,151	116,434	118,763	121,138	123,561	126,032	128,553	131,124	133,746	136,421	139,149	141,932	144,771	147,667	150,620	153,632
Natural Gas	10,431	10,640	10,853	11,070	11,291	11,517	11,747	11,982	12,222	12,466	12,716	12,970	13,229	13,494	13,764	14,039	14,320	14,606	14,899	15,197
Biogas Upgrading O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vehicle Fueling O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional Staffing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Transmission Injection	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Parasitic Electrical	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total running costs	**115,889**	**118,207**	**120,571**	**122,983**	**125,442**	**127,951**	**130,510**	**166,432**	**169,761**	**173,156**	**176,619**	**180,152**	**183,755**	**187,430**	**191,178**	**195,002**	**198,902**	**202,880**	**206,938**	**211,076**
Discounted Running Costs (in 2020$)	**115,889**	**114,764**	**113,650**	**112,547**	**111,454**	**110,372**	**109,300**	**135,325**	**134,011**	**132,710**	**131,421**	**130,145**	**128,882**	**127,631**	**126,391**	**125,164**	**123,949**	**122,746**	**121,554**	**120,374**
		0																		
Net escalated benefit/(cost)	(124,623)	(127,115)	(129,657)	(132,250)	(134,895)	(137,593)	(140,345)	9,241,289	(204,925)	(209,024)	(213,204)	(217,468)	(221,817)	(226,254)	(230,779)	437,540	(240,102)	(244,904)	(249,803)	(4,446,044)

Life cycle cost analysis

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
PVs in 2020	(124,623)	(123,413)	(122,214)	(121,028)	(119,853)	(118,689)	(117,537)	7,514,014	(161,770)	(160,199)	(158,644)	(157,104)	(155,578)	(154,068)	(152,572)	280,840	(149,624)	(148,171)	(146,733)	(2,535,517)
Cumulative Benefits Payback	**(124,623)**	**(248,035)**	**(370,249)**	**(491,277)**	**(611,130)**	**(729,819)**	**(847,356)**	**6,666,658**	**6,504,888**	**6,344,689**	**6,186,045**	**6,028,941**	**5,873,363**	**5,719,295**	**5,566,723**	**5,847,563**	**5,697,939**	**5,549,768**	**5,403,036**	**2,867,519**
NPV as of 2020	**2,867,519**																			

Year of analysis	2020	Risk adjustments (+/- percent):	
Escalation rate	2.00%	Benefits	0%
Discount rate	3.00%	Capital costs	
		Running costs	

Alternative 1A
Status Quo - Replace one engine, second existing engine remains as standby
Life Cycle Alternative Cost Analysis ($)

Expressed in 2020 dollars, unescalated -- dollars

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capital Outlays																				
Engine replacement + Siloxane Removal								3,500,000												
Pump and blower replacement																500,000				
Total capital outlays	0	0	0	0	0	0	0	3,500,000	0	0	0	0	0	0	0	500,000	0	0	0	0
Benefits:																				
Power Savings	(190,592)	(190,592)	(190,592)	(190,592)	(190,592)	(190,592)	(190,592)	(242,884)	(242,884)	(242,884)	(242,884)	(242,884)	(242,884)	(242,884)	(242,884)	(242,884)	(242,884)	(242,884)	(242,884)	(242,884)
Engine Salvage																				(1,225,000)
RIN Revenue																				
CNG Sale																				
Peak shaving/curtailment credit	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)
Total benefits	(240,512)	(240,512)	(240,512)	(240,512)	(240,512)	(240,512)	(240,512)	(292,804)	(292,804)	(292,804)	(292,804)	(292,804)	(292,804)	(292,804)	(292,804)	(292,804)	(292,804)	(292,804)	(292,804)	(1,517,804)
Annual Running Costs:																				
Engine O&M	105,458	105,458	105,458	105,458	105,458	105,458	105,458	105,458		458	105,458	105,458	105,458	105,458	105,458	105,458	105,458	105,458	105,458	105,458
Natural Gas	10,431	10,431	10,431	10,431	10,431	10,431	10,431	10,431		431	10,431	10,431	10,431	10,431	10,431	10,431	10,431	10,431	10,431	10,431
Biogas Upgrading O&M																				
Vehicle Fueling O&M																				
Additional Staffing																				
Gas Transmission Injection																				
Parasitic Electrical																				
Siloxane Removal Media/Landfill								29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000	29,000
Total running costs	115,889	115,889	115,889	115,889	115,889	115,889	115,889	144,889	144,889	144,889										
Net Benefit/(cost)	(124,623)	(124,623)	(124,623)	(124,623)	(124,623)	(124,623)	(124,623)	3,352,086	(147,914)	(147,914)										

Windows User:
assume same O&M even though engine output higher since function of run hours

Expressed in escalated dollars with sensitivity adjustments

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capital Outlays																				
Engine replacement + Siloxane Removal	0	0	0	0	0	0	0	4,020,400	0	0	0	0	0	0	0	0	0	0	0	0
Pump and blower replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	672,934	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	0	0	0	0	0	0	0	4,020,400	0	0	0	0	0	0	0	672,934	0	0	0	0
Benefits:																				
Power Savings	(190,592)	(194,404)	(198,292)	(202,258)	(206,303)	(210,429)	(214,637)	(278,997)	(284,577)	(290,269)	(296,074)	(301,995)	(308,035)	(314,196)	(320,480)	(326,890)	(333,427)	(340,096)	(346,898)	(353,836)
Engine Salvage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,784,594)
RIN Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CNG Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak shaving/curtailment credit	(49,920)	(50,918)	(51,937)	(52,976)	(54,035)	(55,116)	(56,218)	(57,342)	(58,489)	(59,659)	(60,852)	(62,069)	(63,311)	(64,577)	(65,868)	(67,186)	(68,529)	(69,900)	(71,298)	(72,724)
Total benefits	(240,512)	(245,322)	(250,228)	(255,233)	(260,338)	(265,544)	(270,855)	(336,339)	(343,066)	(349,928)	(356,926)	(364,065)	(371,346)	(378,773)	(386,348)	(394,075)	(401,957)	(409,996)	(418,196)	(2,211,153)
Discounted Benefits (in 2020$)	(240,512)	(238,177)	(235,864)	(233,574)	(231,307)	(229,061)	(226,837)	(273,475)	(270,820)	(268,190)	(265,587)	(263,008)	(260,455)	(257,926)	(255,422)	(252,942)	(250,486)	(248,054)	(245,646)	(1,260,990)
Annual Running Costs:																				
Engine O&M	105,458	107,567	109,718	111,913	114,151	116,434	118,763	121,138	123,561	126,032	128,553	131,124	133,746	136,421	139,149	141,932	144,771	147,667	150,620	153,632
Natural Gas	10,431	10,640	10,853	11,070	11,291	11,517	11,747	11,982	12,222	12,466	12,716	12,970	13,229	13,494	13,764	14,039	14,320	14,606	14,899	15,197
Biogas Upgrading O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vehicle Fueling O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional Staffing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Transmission Injection	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Parasitic Electrical	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total running costs	115,889	118,207	120,571	122,983	125,442	127,951	130,510	166,432	169,761	173,156	176,619	180,152	183,755	187,430	191,178	195,002	198,902	202,880	206,938	211,076
Discounted Running Costs (in 2020$)	115,889	114,764	113,650	112,547	111,454	110,372	109,300	135,325	134,011	132,710	131,421	130,145	128,882	127,631	126,391	125,164	123,949	122,746	121,554	120,374
		0																		
Net escalated benefit/(cost)	(124,623)	(127,115)	(129,657)	(132,250)	(134,895)	(137,593)	(140,345)	3,850,493	(173,305)	(176,771)	(180,307)	(183,913)	(187,591)	(191,343)	(195,170)	473,861	(203,055)	(207,116)	(211,258)	(2,000,077)

Life cycle cost analysis

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
PVs in 2020	(124,623)	(123,413)	(122,214)	(121,028)	(119,853)	(118,689)	(117,537)	3,130,803	(136,809)	(135,481)	(134,165)	(132,863)	(131,573)	(130,295)	(129,030)	304,153	(126,537)	(125,309)	(124,092)	(1,140,616)
Cumulative Benefits Payback	(124,623)	(248,035)	(370,249)	(491,277)	(611,130)	(729,819)	(847,356)	2,283,447	2,146,638	2,011,157	1,876,992	1,744,129	1,612,556	1,482,261	1,353,231	1,657,384	1,530,847	1,405,538	1,281,446	140,830
NPV as of 2020	140,830																			

Risk adjustments (+/- percent):			
Year of analysis	2020	Benefits	0%
Escalation rate	2%	Capital costs	0%
Discount rate	3%	Running costs	0%

Alternative 3
Microturbines with Siloxane Removal
Life Cycle Alternative Cost Analysis ($)

Expressed in 2020 dollars, unescalated -- dollars

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capital Outlays																				
Microturbines + Gas Treatment	6,900,000																			
Pump and compressor replacement																500,000				
Total capital outlays	6,900,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	500,000	0	0	0	0
Benefits:																				
Power Savings	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)	(204,173)
Engine Salvage																				
RIN Revenue																				
CNG Sale																				
Peak shaving/curtailment credit	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)	(49,920)
Total benefits	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)	(254,093)
Annual Running Costs:																				
Microturbine O&M	75,058	75,058	75,058	75,058	75,058	75,058	75,058	75,058	[illegible]	[illegible]	75,058	75,058	75,058	75,058	75,058	75,058	75,058	75,058	75,058	75,058
Natural Gas	86,549	86,549	86,549	86,549	86,549	86,549	86,549	86,549	[illegible]	[illegible]	86,549	86,549	86,549	86,549	86,549	86,549	86,549	86,549	86,549	86,549
Biogas Upgrading O&M																				
Vehicle Fueling O&M																				
Additional Staffing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Transmission Injection																				
Siloxane Removal Media/Landfill	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000
Parasitic Electrical																				
Peak shaving/curtailment credit																				
Total running costs	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607	195,607
Net Benefit/(cost)	6,841,514	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	(58,486)	441,514	(58,486)	(58,486)	(58,486)	(58,486)

Windows User:
assume same O&M even though engine output higher since function of run hours

Expressed in escalated dollars with sensitivity adjustments

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capital Outlays																				
Microturbines + Gas Treatment	6,900,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pump and compressor replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	672,934	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	6,900,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	672,934	0	0	0	0
Benefits:																				
Power Savings	(204,173)	(208,256)	(212,421)	(216,670)	(221,003)	(225,423)	(229,932)	(234,530)	(239,221)	(244,005)	(248,885)	(253,863)	(258,940)	(264,119)	(269,401)	(274,790)	(280,285)	(285,891)	(291,609)	(297,441)
Engine Salvage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RIN Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CNG Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak shaving/curtailment credit	(49,920)	(50,918)	(51,937)	(52,976)	(54,035)	(55,116)	(56,218)	(57,342)	(58,489)	(59,659)	(60,852)	(62,069)	(63,311)	(64,577)	(65,868)	(67,186)	(68,529)	(69,900)	(71,298)	(72,724)
Total benefits	(254,093)	(259,175)	(264,358)	(269,645)	(275,038)	(280,539)	(286,150)	(291,873)	(297,710)	(303,664)	(309,738)	(315,932)	(322,251)	(328,696)	(335,270)	(341,975)	(348,815)	(355,791)	(362,907)	(370,165)
Discounted Benefits (in 2020$)	(254,093)	(251,626)	(249,183)	(246,764)	(244,368)	(241,995)	(239,646)	(237,319)	(235,015)	(232,733)	(230,474)	(228,236)	(226,020)	(223,826)	(221,653)	(219,501)	(217,370)	(215,259)	(213,170)	(211,100)
Annual Running Costs:																				
Microturbine O&M	75,058	76,559	78,090	79,652	81,245	82,870	84,528	86,218	87,942	89,701	91,495	93,325	95,192	97,096	99,038	101,018	103,039	105,099	107,201	109,345
Natural Gas	86,549	88,280	90,045	91,846	93,683	95,557	97,468	99,417	101,406	103,434	105,503	107,613	109,765	111,960	114,199	116,483	118,813	121,189	123,613	126,085
Biogas Upgrading O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vehicle Fueling O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional Staffing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Transmission Injection	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Siloxane Removal Media/Landfill	34,000	34,680	35,374	36,081	36,803	37,539	38,290	39,055	39,836	40,633	41,446	42,275	43,120	43,983	44,862	45,760	46,675	47,608	48,560	49,532
Parasitic Electrical	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak shaving/curtailment credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total running costs	195,607	199,519	203,509	207,580	211,731	215,966	220,285	224,691	229,185	233,768	238,444	243,213	248,077	253,038	258,099	263,261	268,526	273,897	279,375	284,962
Discounted Running Costs (in 2020$)	195,607	193,708	191,827	189,965	188,120	186,294	184,485	182,694	180,920	179,164	177,424	175,702	173,996	172,307	170,634	168,977	167,337	165,712	164,103	162,510
		0																		
Net escalated benefit/(cost)	6,841,514	(59,656)	(60,849)	(62,066)	(63,307)	(64,573)	(65,865)	(67,182)	(68,525)	(69,896)	(71,294)	(72,720)	(74,174)	(75,658)	(77,171)	594,220	(80,288)	(81,894)	(83,532)	(85,203)

Life cycle cost analysis

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
PVs in 2020	6,841,514	(57,918)	(57,356)	(56,799)	(56,247)	(55,701)	(55,160)	(54,625)	(54,095)	(53,569)	(53,049)	(52,534)	(52,024)	(51,519)	(51,019)	381,407	(50,033)	(49,547)	(49,066)	(48,590)
Cumulative Benefits Payback	6,841,514	6,783,596	6,726,241	6,669,442	6,613,194	6,557,493	6,502,333	6,447,708	6,393,613	6,340,044	6,286,994	6,234,460	6,182,436	6,130,916	6,079,897	6,461,305	6,411,272	6,361,724	6,312,658	6,264,068
NPV as of 2020	6,543,853																			

		Risk adjustments (+/- percent):	
Year of analysis	**2020**	**Benefits**	**0%**
Escalation rate	**2%**	**Capital costs**	**0%**
Discount rate	**3%**	**Running costs**	**0%**

D3 RINs

Alternative 4
Biogas Upgrading to Pipeline Injection
Life Cycle Alternative Cost Analysis ($)

	Year																			
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Expressed in 2020 dollars, unescalated -- dollars																				
Capital Outlays																				
Biogas Upgrading System	10,200,000																			
Compressor replacement																1,000,000				
Total capital outlays	**10,200,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**										
Benefits:																				
Power Savings																				
Engine Salvage																				
RIN Revenue	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)
CNG Sale	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)
Total benefits	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**	**(1,668,810)**
Annual Running Costs:																				
Cogeneration O&M	0	0	0	0	0	0	0	0	[illegible]	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	[illegible]	[illegible]	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755
Biogas Upgrading O&M	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	[illegible]	[illegible]	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476
Vehicle Fueling O&M																				
Additional Staffing	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Gas Transmission Injection	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678
Electricity	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431
RIN QAP	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Total running costs	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**
Net Benefit/(cost)	**9,360,529**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**	**(839,471)**

Windows User:
assume same O&M even though engine output higher since function of run hours

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Expressed in escalated dollars with sensitivity adjustments																				
Capital Outlays																				
Biogas Upgrading System	10,200,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compressor replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,345,868	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**10,200,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1,345,868**	**0**	**0**	**0**	**0**
Benefits:																				
Power Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine Salvage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RIN Revenue	(1,458,031)	(1,487,191)	(1,516,935)	(1,547,274)	(1,578,219)	(1,609,784)	(1,641,980)	(1,674,819)	(1,708,315)	(1,742,482)	(1,777,331)	(1,812,878)	(1,849,136)	(1,886,118)	(1,923,841)	(1,962,317)	(2,001,564)	(2,041,595)	(2,082,427)	(2,124,076)
CNG Sale	(210,779)	(214,995)	(219,295)	(223,681)	(228,154)	(232,717)	(237,372)	(242,119)	(246,962)	(251,901)	(256,939)	(262,078)	(267,319)	(272,666)	(278,119)	(283,681)	(289,355)	(295,142)	(301,045)	(307,066)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefits	**(1,668,810)**	**(1,702,186)**	**(1,736,230)**	**(1,770,955)**	**(1,806,374)**	**(1,842,501)**	**(1,879,351)**	**(1,916,938)**	**(1,955,277)**	**(1,994,383)**	**(2,034,270)**	**(2,074,956)**	**(2,116,455)**	**(2,158,784)**	**(2,201,960)**	**(2,245,999)**	**(2,290,919)**	**(2,336,737)**	**(2,383,472)**	**(2,431,141)**
Discounted Benefits (in 2020$)	**(1,668,810)**	**(1,652,608)**	**(1,636,563)**	**(1,620,674)**	**(1,604,940)**	**(1,589,358)**	**(1,573,927)**	**(1,558,646)**	**(1,543,514)**	**(1,528,528)**	**(1,513,688)**	**(1,498,992)**	**(1,484,439)**	**(1,470,027)**	**(1,455,755)**	**(1,441,621)**	**(1,427,625)**	**(1,413,764)**	**(1,400,039)**	**(1,386,446)**
Annual Running Costs:																				
Cogeneration O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	424,755	433,250	441,915	450,753	459,768	468,964	478,343	487,910	497,668	507,621	517,774	528,129	538,692	549,466	560,455	571,664	583,097	594,759	606,655	618,788
Biogas Upgrading O&M	122,476	124,925	127,424	129,972	132,572	135,223	137,927	140,686	143,500	146,370	149,297	152,283	155,329	158,435	161,604	164,836	168,133	171,495	174,925	178,424
Vehicle Fueling O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional Staffing	35,000	35,700	36,414	37,142	37,885	38,643	39,416	40,204	41,008	41,828	42,665	43,518	44,388	45,276	46,182	47,105	48,047	49,008	49,989	50,988
Gas Transmission Injection	78,678	80,252	81,857	83,494	85,164	86,867	88,605	90,377	92,184	94,028	95,908	97,827	99,783	101,779	103,814	105,891	108,009	110,169	112,372	114,620
Electricity	118,431	120,799	123,215	125,680	128,193	130,757	133,372	136,040	138,760	141,536	144,366	147,254	150,199	153,203	156,267	159,392	162,580	165,832	169,148	172,531
RIN QAP	50,000	51,000	52,020	53,060	54,122	55,204	56,308	57,434	58,583	59,755	60,950	62,169	63,412	64,680	65,974	67,293	68,639	70,012	71,412	72,841
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total running costs	**829,340**	**845,926**	**862,845**	**880,102**	**897,704**	**915,658**	**933,971**	**952,650**	**971,703**	**991,138**	**1,010,960**	**1,031,180**	**1,051,803**	**1,072,839**	**1,094,296**	**1,116,182**	**1,138,505**	**1,161,276**	**1,184,501**	**1,208,191**
Discounted Running Costs (in 2020$)	**829,340**	**821,288**	**813,314**	**805,418**	**797,598**	**789,855**	**782,186**	**774,592**	**767,072**	**759,624**	**752,249**	**744,946**	**737,714**	**730,551**	**723,459**	**716,435**	**709,479**	**702,591**	**695,770**	**689,015**
		0																		
Net escalated benefit/(cost)	**9,360,529**	**(856,260)**	**(873,385)**	**(890,853)**	**(908,670)**	**(926,843)**	**(945,380)**	**(964,288)**	**(983,574)**	**(1,003,245)**	**(1,023,310)**	**(1,043,776)**	**(1,064,652)**	**(1,085,945)**	**(1,107,664)**	**216,051**	**(1,152,413)**	**(1,175,461)**	**(1,198,971)**	**(1,222,950)**
Life cycle cost analysis																				
PVs in 2020	9,360,529	(831,320)	(823,249)	(815,257)	(807,341)	(799,503)	(791,741)	(784,054)	(776,442)	(768,904)	(761,439)	(754,046)	(746,725)	(739,476)	(732,296)	138,675	(718,146)	(711,174)	(704,269)	(697,431)
Cumulative Benefits Payback	**9,360,529**	**8,529,209**	**7,705,960**	**6,890,703**	**6,083,362**	**5,283,858**	**4,492,117**	**3,708,063**	**2,931,621**	**2,162,717**	**1,401,279**	**647,232**	**(99,493)**	**(838,968)**	**(1,571,264)**	**(1,432,589)**	**(2,150,735)**	**(2,861,909)**	**(3,566,178)**	**(4,263,609)**
NPV as of 2020	**(3,751,724)**																			

D5 RINs

Alternative 4
Biogas Upgrading to Pipeline Injection
Life Cycle Alternative Cost Analysis ($)

Year of analysis	2020	**Benefits**	0%
Escalation rate	2%	**Capital costs**	0%
Discount rate	3%	**Running costs**	0%

Risk adjustments (+/- percent): (applies to Benefits, Capital costs, Running costs above)

Expressed in 2020 dollars, unescalated -- dollars

	Year																			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capital Outlays																				
Biogas Upgrading System	10,200,000																			
Compressor replacement																1,000,000				
Total capital outlays	**10,200,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**										
Benefits:																				
Power Savings																				
Engine Salvage																				
RIN Revenue	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)	(387,199)
CNG Sale	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)	(210,779)
Total benefits	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**	**(597,978)**
Annual Running Costs:																				
Cogeneration O&M	0	0	0	0	0	0	0	0	[illegible]	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	[illegible]	[illegible]	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755
Biogas Upgrading O&M	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	[illegible]	[illegible]	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476
Vehicle Fueling O&M																				
Additional Staffing	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Gas Transmission Injection	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678	78,678
Electricity	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431	118,431
RIN QAP	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Total running costs	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**	**829,340**
Net Benefit/(cost)	**10,431,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**	**231,361**

Windows User:
assume same O&M even though engine output higher since function of run hours

Expressed in escalated dollars with sensitivity adjustments

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capital Outlays																				
Biogas Upgrading System	10,200,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compressor replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,345,868	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**10,200,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1,345,868**	**0**	**0**	**0**	**0**
Benefits:																				
Power Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine Salvage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RIN Revenue	(387,199)	(394,943)	(402,842)	(410,899)	(419,117)	(427,499)	(436,049)	(444,770)	(453,665)	(462,739)	(471,993)	(481,433)	(491,062)	(500,883)	(510,901)	(521,119)	(531,541)	(542,172)	(553,016)	(564,076)
CNG Sale	(210,779)	(214,995)	(219,295)	(223,681)	(228,154)	(232,717)	(237,372)	(242,119)	(246,962)	(251,901)	(256,939)	(262,078)	(267,319)	(272,666)	(278,119)	(283,681)	(289,355)	(295,142)	(301,045)	(307,066)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefits	**(597,978)**	**(609,938)**	**(622,137)**	**(634,579)**	**(647,271)**	**(660,216)**	**(673,421)**	**(686,889)**	**(700,627)**	**(714,639)**	**(728,932)**	**(743,511)**	**(758,381)**	**(773,549)**	**(789,020)**	**(804,800)**	**(820,896)**	**(837,314)**	**(854,060)**	**(871,142)**
Discounted Benefits (in 2020$)	**(597,978)**	**(592,173)**	**(586,423)**	**(580,730)**	**(575,092)**	**(569,508)**	**(563,979)**	**(558,504)**	**(553,081)**	**(547,712)**	**(542,394)**	**(537,128)**	**(531,913)**	**(526,749)**	**(521,635)**	**(516,571)**	**(511,555)**	**(506,589)**	**(501,670)**	**(496,800)**
Annual Running Costs:																				
Cogeneration O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	424,755	433,250	441,915	450,753	459,768	468,964	478,343	487,910	497,668	507,621	517,774	528,129	538,692	549,466	560,455	571,664	583,097	594,759	606,655	618,788
Biogas Upgrading O&M	122,476	124,925	127,424	129,972	132,572	135,223	137,927	140,686	143,500	146,370	149,297	152,283	155,329	158,435	161,604	164,836	168,133	171,495	174,925	178,424
Vehicle Fueling O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional Staffing	35,000	35,700	36,414	37,142	37,885	38,643	39,416	40,204	41,008	41,828	42,665	43,518	44,388	45,276	46,182	47,105	48,047	49,008	49,989	50,988
Gas Transmission Injection	78,678	80,252	81,857	83,494	85,164	86,867	88,605	90,377	92,184	94,028	95,908	97,827	99,783	101,779	103,814	105,891	108,009	110,169	112,372	114,620
Electricity	118,431	120,799	123,215	125,680	128,193	130,757	133,372	136,040	138,760	141,536	144,366	147,254	150,199	153,203	156,267	159,392	162,580	165,832	169,148	172,531
RIN QAP	50,000	51,000	52,020	53,060	54,122	55,204	56,308	57,434	58,583	59,755	60,950	62,169	63,412	64,680	65,974	67,293	68,639	70,012	71,412	72,841
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total running costs	**829,340**	**845,926**	**862,845**	**880,102**	**897,704**	**915,658**	**933,971**	**952,650**	**971,703**	**991,138**	**1,010,960**	**1,031,180**	**1,051,803**	**1,072,839**	**1,094,296**	**1,116,182**	**1,138,505**	**1,161,276**	**1,184,501**	**1,208,191**
Discounted Running Costs (in 2020$)	**829,340**	**821,288**	**813,314**	**805,418**	**797,598**	**789,855**	**782,186**	**774,592**	**767,072**	**759,624**	**752,249**	**744,946**	**737,714**	**730,551**	**723,459**	**716,435**	**709,479**	**702,591**	**695,770**	**689,015**
		0																		
Net escalated benefit/(cost)	**10,431,361**	**235,988**	**240,708**	**245,522**	**250,433**	**255,441**	**260,550**	**265,761**	**271,077**	**276,498**	**282,028**	**287,669**	**293,422**	**299,290**	**305,276**	**1,657,250**	**317,609**	**323,962**	**330,441**	**337,050**

Life cycle cost analysis

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
PVs in 2020	10,431,361	229,115	226,891	224,688	222,506	220,346	218,207	216,088	213,990	211,913	209,855	207,818	205,800	203,802	201,824	1,063,726	197,924	196,002	194,099	192,215
Cumulative Benefits Payback	**10,431,361**	**10,660,476**	**10,887,367**	**11,112,055**	**11,334,561**	**11,554,907**	**11,773,114**	**11,989,202**	**12,203,192**	**12,415,105**	**12,624,960**	**12,832,778**	**13,038,579**	**13,242,381**	**13,444,204**	**14,507,930**	**14,705,854**	**14,901,856**	**15,095,955**	**15,288,170**
NPV as of 2020	**16,118,616**																			

Year of analysis	2020	Risk adjustments (+/- percent): Benefits	0%	
Escalation rate	2%	Capital costs	0%	
Discount rate	3%	Running costs	0%	

D5 RINs

Alternative 5
Onsite Vehicle Fueling
Life Cycle Alternative Cost Analysis ($)

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Expressed in 2020 dollars, unescalated -- dollars																				
Capital Outlays																				
Biogas Upgrading System	15,600,000																			
Compressor replacement																1,000,000				
Total capital outlays	**15,600,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**										
Benefits:																				
Power Savings																				
Engine Salvage																				
RIN Revenue	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)	(1,458,031)
CNG Sale	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)
Total benefits	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**	**(2,690,659)**
Annual Running Costs:																				
Cogeneration O&M	0	0	0	0	0	0	0	0	[illegible]	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	424,625	424,755	424,755	424,755	424,755	424,755	424,755	424,755	[illegible]	[illegible]	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755
Biogas Upgrading O&M	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	[illegible]	[illegible]	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476
Vehicle Fueling O&M	81,650	81,650	81,650	81,650	81,650	81,650	81,650	81,650	[illegible]	[illegible]	81,650	81,650	81,650	81,650	81,650	81,650	81,650	81,650	81,650	81,650
Additional Staffing	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Gas Transmission Injection																				
Electricity	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293
RIN QAP	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Total running costs	**902,045**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**
Net Benefit/(cost)	**13,811,386**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**	**(1,788,484)**
Expressed in escalated dollars with sensitivity adjustments																				
Capital Outlays																				
Biogas Upgrading System	15,600,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compressor replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,345,868	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**15,600,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1,345,868**	**0**	**0**	**0**	**0**
Benefits:																				
Power Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine Salvage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RIN Revenue	(1,458,031)	(1,487,191)	(1,516,935)	(1,547,274)	(1,578,219)	(1,609,784)	(1,641,980)	(1,674,819)	(1,708,315)	(1,742,482)	(1,777,331)	(1,812,878)	(1,849,136)	(1,886,118)	(1,923,841)	(1,962,317)	(2,001,564)	(2,041,595)	(2,082,427)	(2,124,076)
CNG Sale	(1,232,628)	(1,257,280)	(1,282,426)	(1,308,074)	(1,334,236)	(1,360,921)	(1,388,139)	(1,415,902)	(1,444,220)	(1,473,104)	(1,502,566)	(1,532,618)	(1,563,270)	(1,594,535)	(1,626,426)	(1,658,955)	(1,692,134)	(1,725,976)	(1,760,496)	(1,795,706)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefits	**(2,690,659)**	**(2,744,472)**	**(2,799,361)**	**(2,855,348)**	**(2,912,455)**	**(2,970,704)**	**(3,030,119)**	**(3,090,721)**	**(3,152,535)**	**(3,215,586)**	**(3,279,898)**	**(3,345,496)**	**(3,412,406)**	**(3,480,654)**	**(3,550,267)**	**(3,621,272)**	**(3,693,698)**	**(3,767,572)**	**(3,842,923)**	**(3,919,781)**
Discounted Benefits (in 2020$)	**(2,690,659)**	**(2,664,536)**	**(2,638,666)**	**(2,613,048)**	**(2,587,679)**	**(2,562,556)**	**(2,537,677)**	**(2,513,039)**	**(2,488,640)**	**(2,464,479)**	**(2,440,552)**	**(2,416,857)**	**(2,393,393)**	**(2,370,156)**	**(2,347,145)**	**(2,324,357)**	**(2,301,790)**	**(2,279,443)**	**(2,257,312)**	**(2,235,397)**
Annual Running Costs:																				
Cogeneration O&M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	424,625	433,250	441,915	450,753	459,768	468,964	478,343	487,910	497,668	507,621	517,774	528,129	538,692	549,466	560,455	571,664	583,097	594,759	606,655	618,788
Biogas Upgrading O&M	122,476	124,925	127,424	129,972	132,572	135,223	137,927	140,686	143,500	146,370	149,297	152,283	155,329	158,435	161,604	164,836	168,133	171,495	174,925	178,424
Vehicle Fueling O&M	81,650	83,283	84,949	86,648	88,381	90,149	91,952	93,791	95,667	97,580	99,531	101,522	103,553	105,624	107,736	109,891	112,089	114,330	116,617	118,949
Additional Staffing	70,000	71,400	72,828	74,285	75,770	77,286	78,831	80,408	82,016	83,656	85,330	87,036	88,777	90,552	92,364	94,211	96,095	98,017	99,977	101,977
Gas Transmission Injection	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electricity	153,293	156,359	159,487	162,676	165,930	169,248	172,633	176,086	179,608	183,200	186,864	190,601	194,413	198,301	202,267	206,313	210,439	214,648	218,941	223,320
RIN QAP	50,000	51,000	52,020	53,060	54,122	55,204	56,308	57,434	58,583	59,755	60,950	62,169	63,412	64,680	65,974	67,293	68,639	70,012	71,412	72,841
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total running costs	**902,045**	**920,218**	**938,622**	**957,395**	**976,543**	**996,073**	**1,015,995**	**1,036,315**	**1,057,041**	**1,078,182**	**1,099,746**	**1,121,741**	**1,144,175**	**1,167,059**	**1,190,400**	**1,214,208**	**1,238,492**	**1,263,262**	**1,288,527**	**1,314,298**
Discounted Running Costs (in 2020$)	**902,045**	**893,415**	**884,742**	**876,152**	**867,645**	**859,222**	**850,880**	**842,619**	**834,438**	**826,337**	**818,314**	**810,369**	**802,502**	**794,710**	**786,995**	**779,354**	**771,787**	**764,294**	**756,874**	**749,526**
		0																		
Net escalated benefit/(cost)	**13,811,386**	**(1,824,254)**	**(1,860,739)**	**(1,897,954)**	**(1,935,913)**	**(1,974,631)**	**(2,014,124)**	**(2,054,406)**	**(2,095,494)**	**(2,137,404)**	**(2,180,152)**	**(2,223,755)**	**(2,268,230)**	**(2,313,595)**	**(2,359,867)**	**(1,061,196)**	**(2,455,205)**	**(2,504,310)**	**(2,554,396)**	**(2,605,484)**
Life cycle cost analysis																				
PVs in 2020	13,811,386	(1,771,120)	(1,753,925)	(1,736,896)	(1,720,033)	(1,703,334)	(1,686,797)	(1,670,420)	(1,654,202)	(1,638,142)	(1,622,238)	(1,606,488)	(1,590,891)	(1,575,446)	(1,560,150)	(681,141)	(1,530,003)	(1,515,148)	(1,500,438)	(1,485,871)
Cumulative Benefits Payback	**13,811,386**	**12,040,266**	**10,286,341**	**8,549,445**	**6,829,411**	**5,126,077**	**3,439,280**	**1,768,860**	**114,658**	**(1,523,484)**	**(3,145,722)**	**(4,752,210)**	**(6,343,101)**	**(7,918,547)**	**(9,478,697)**	**(10,159,838)**	**(11,689,841)**	**(13,204,989)**	**(14,705,428)**	**(16,191,298)**
NPV as of 2020	**(15,554,758)**																			

Windows User:
assume same O&M even though engine output higher since function of run hours

		Risk adjustments (+/- percent):	
Year of analysis	2020	**Benefits**	0%
Escalation rate	2%	**Capital costs**	0%
Discount rate	3%	**Running costs**	0%

D3 RINs

Alternative 5
Onsite Vehicle Fueling
Life Cycle Alternative Cost Analysis ($)

Year

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Expressed in 2020 dollars, unescalated -- dollars										
Capital Outlays										
Biogas Upgrading System	15,600,000									
Compressor replacement										
Total capital outlays	**15,600,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:										
Power Savings										
Engine Salvage										
RIN Revenue	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)
CNG Sale	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)
Total benefits	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**
Annual Running Costs:										
Cogeneration O&M	0	0	0	0	0	0	0	0	[illegible]	0
Natural Gas	424,625	424,755	424,755	424,755	424,755	424,755	424,755	424,755	[illegible]	55
Biogas Upgrading O&M	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	[illegible]	76
Vehicle Fueling O&M	81,650	81,650	81,650	81,650	81,650	81,650	81,650	81,650	[illegible]	50
Additional Staffing	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Gas Transmission Injection										
Electricity	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293
RIN QAP	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Total running costs	**902,045**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**
	900	900	900	900	900	900	900	900	900	900
Net Benefit/(cost)	**14,891,843**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**
Expressed in escalated dollars with sensitivity adjustments										
Capital Outlays										
Biogas Upgrading System	15,600,000	0	0	0	0	0	0	0	0	0
Compressor replacement	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**15,600,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:										
Power Savings	0	0	0	0	0	0	0	0	0	0
Engine Salvage	0	0	0	0	0	0	0	0	0	0
RIN Revenue	(377,574)	(385,125)	(392,828)	(400,684)	(408,698)	(416,872)	(425,209)	(433,713)	(442,388)	(451,236)
CNG Sale	(1,232,628)	(1,257,280)	(1,282,426)	(1,308,074)	(1,334,236)	(1,360,921)	(1,388,139)	(1,415,902)	(1,444,220)	(1,473,104)
0	0	0	0	0	0	0	0	0	0	0
Total benefits	**(1,610,201)**	**(1,642,405)**	**(1,675,254)**	**(1,708,759)**	**(1,742,934)**	**(1,777,792)**	**(1,813,348)**	**(1,849,615)**	**(1,886,608)**	**(1,924,340)**
Discounted Benefits (in 2020$)	**(1,610,201)**	**(1,594,568)**	**(1,579,087)**	**(1,563,756)**	**(1,548,574)**	**(1,533,539)**	**(1,518,651)**	**(1,503,906)**	**(1,489,305)**	**(1,474,846)**
Annual Running Costs:										
Cogeneration O&M	0	0	0	0	0	0	0	0	0	0
Natural Gas	424,625	433,250	441,915	450,753	459,768	468,964	478,343	487,910	497,668	507,621
Biogas Upgrading O&M	122,476	124,925	127,424	129,972	132,572	135,223	137,927	140,686	143,500	146,370
Vehicle Fueling O&M	81,650	83,283	84,949	86,648	88,381	90,149	91,952	93,791	95,667	97,580
Additional Staffing	70,000	71,400	72,828	74,285	75,770	77,286	78,831	80,408	82,016	83,656
Gas Transmission Injection	0	0	0	0	0	0	0	0	0	0
Electricity	153,293	156,359	159,487	162,676	165,930	169,248	172,633	176,086	179,608	183,200
RIN QAP	50,000	51,000	52,020	53,060	54,122	55,204	56,308	57,434	58,583	59,755
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
Total running costs	**902,045**	**920,218**	**938,622**	**957,395**	**976,543**	**996,073**	**1,015,995**	**1,036,315**	**1,057,041**	**1,078,182**
Discounted Running Costs (in 2020$)	**902,045**	**893,415**	**884,742**	**876,152**	**867,645**	**859,222**	**850,880**	**842,619**	**834,438**	**826,337**
		0								
Net escalated benefit/(cost)	**14,891,843**	**(722,188)**	**(736,631)**	**(751,364)**	**(766,391)**	**(781,719)**	**(797,353)**	**(813,300)**	**(829,566)**	**(846,158)**
Life cycle cost analysis										
PVs in 2020	14,891,843	(701,153)	(694,346)	(687,604)	(680,929)	(674,318)	(667,771)	(661,288)	(654,867)	(648,509)
Cumulative Benefits Payback	**14,891,843**	**14,190,690**	**13,496,345**	**12,808,740**	**12,127,812**	**11,453,494**	**10,785,723**	**10,124,435**	**9,469,568**	**8,821,058**
NPV as of 2020	4,416,230									

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Expressed in 2020 dollars, unescalated -- dollars										
Capital Outlays										
Biogas Upgrading System										
Compressor replacement						1,000,000				
Total capital outlays										
Benefits:										
Power Savings										
Engine Salvage										
RIN Revenue	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)	(377,574)
CNG Sale	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)	(1,232,628)
Total benefits	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**	**(1,610,201)**
Annual Running Costs:										
Cogeneration O&M	0	0	0	0	0	0	0	0	0	0
Natural Gas	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755	424,755
Biogas Upgrading O&M	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476	122,476
Vehicle Fueling O&M	81,650	81,650	81,650	81,650	81,650	81,650	81,650	81,650	81,650	81,650
Additional Staffing	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Gas Transmission Injection										
Electricity	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293	153,293
RIN QAP	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Total running costs	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**	**902,174**
	900	900	900	900	900	900	900	900	900	900
Net Benefit/(cost)	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**	**(708,027)**
Expressed in escalated dollars with sensitivity adjustments										
Capital Outlays										
Biogas Upgrading System	0	0	0	0	0	0	0	0	0	0
Compressor replacement	0	0	0	0	0	1,345,868	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**0**	**0**	**0**	**0**	**0**	**1,345,868**	**0**	**0**	**0**	**0**
Benefits:										
Power Savings	0	0	0	0	0	0	0	0	0	0
Engine Salvage	0	0	0	0	0	0	0	0	0	0
RIN Revenue	(460,260)	(469,465)	(478,855)	(488,432)	(498,200)	(508,164)	(518,328)	(528,694)	(539,268)	(550,054)
CNG Sale	(1,502,566)	(1,532,618)	(1,563,270)	(1,594,535)	(1,626,426)	(1,658,955)	(1,692,134)	(1,725,976)	(1,760,496)	(1,795,706)
0	0	0	0	0	0	0	0	0	0	0
Total benefits	**(1,962,827)**	**(2,002,083)**	**(2,042,125)**	**(2,082,967)**	**(2,124,627)**	**(2,167,119)**	**(2,210,461)**	**(2,254,671)**	**(2,299,764)**	**(2,345,759)**
Discounted Benefits (in 2020$)	**(1,460,527)**	**(1,446,347)**	**(1,432,305)**	**(1,418,399)**	**(1,404,628)**	**(1,390,991)**	**(1,377,487)**	**(1,364,113)**	**(1,350,869)**	**(1,337,754)**
Annual Running Costs:										
Cogeneration O&M	0	0	0	0	0	0	0	0	0	0
Natural Gas	517,774	528,129	538,692	549,466	560,455	571,664	583,097	594,759	606,655	618,788
Biogas Upgrading O&M	149,297	152,283	155,329	158,435	161,604	164,836	168,133	171,495	174,925	178,424
Vehicle Fueling O&M	99,531	101,522	103,553	105,624	107,736	109,891	112,089	114,330	116,617	118,949
Additional Staffing	85,330	87,036	88,777	90,552	92,364	94,211	96,095	98,017	99,977	101,977
Gas Transmission Injection	0	0	0	0	0	0	0	0	0	0
Electricity	186,864	190,601	194,413	198,301	202,267	206,313	210,439	214,648	218,941	223,320
RIN QAP	60,950	62,169	63,412	64,680	65,974	67,293	68,639	70,012	71,412	72,841
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
Total running costs	**1,099,746**	**1,121,741**	**1,144,175**	**1,167,059**	**1,190,400**	**1,214,208**	**1,238,492**	**1,263,262**	**1,288,527**	**1,314,298**
Discounted Running Costs (in 2020$)	**818,314**	**810,369**	**802,502**	**794,710**	**786,995**	**779,354**	**771,787**	**764,294**	**756,874**	**749,526**
Net escalated benefit/(cost)	**(863,081)**	**(880,343)**	**(897,949)**	**(915,908)**	**(934,227)**	**392,957**	**(971,969)**	**(991,409)**	**(1,011,237)**	**(1,031,462)**
Life cycle cost analysis										
PVs in 2020	(642,213)	(635,978)	(629,804)	(623,689)	(617,634)	252,224	(605,699)	(599,819)	(593,995)	(588,228)
Cumulative Benefits Payback	**8,178,845**	**7,542,867**	**6,913,063**	**6,289,374**	**5,671,740**	**5,923,965**	**5,318,266**	**4,718,447**	**4,124,452**	**3,536,224**

Windows User:
assume same O&M even though engine output higher since function of run hours

Attachment C: MERC Coordination

Alison Nojima

From: O'Sullivan, Paul B <Paul.OSullivan@minnesotaenergyresources.com>
Sent: Monday, June 10, 2019 1:32 PM
To: Nancy Andrews; Wolf, Benjamin D
Cc: Alison Nojima
Subject: RE: Pipe to Waste Water Plant

Hello Nancy and Alison,

We appreciate your interest and inquiry into this project, but after consultation with our upper management, Minnesota Energy Resources has decided not to pursue this project at this time.

Thank You,

Paul O'Sullivan
Senior Account Manager – External Affairs
Minnesota Energy Resources
Office: 507-529-5117
paul.osullivan@minnesotaenergyresources.com

We deliver natural gas safely, reliably, responsibly.

From: Nancy Andrews [mailto:NAndrews@brwncald.com]
Sent: Wednesday, May 15, 2019 4:16 PM
To: O'Sullivan, Paul B; Wolf, Benjamin D
Cc: Alison Nojima
Subject: RE: Pipe to Waste Water Plant

Paul and Ben-

I looked into the issue of pipeline interconnection between the injection site and the vehicle fuel off-take location. Our reading of the requirements is that there needs to be connected pipelines but we don't need to prove that the RNG would flow from the wastewater plant to the RIN purchaser.

Have you had any chance to look into this further or develop a cost for the connection?

Also, do you know if the tie-in point could be on the 2" branch or would you prefer an injection point near the 4" pipeline in the street?

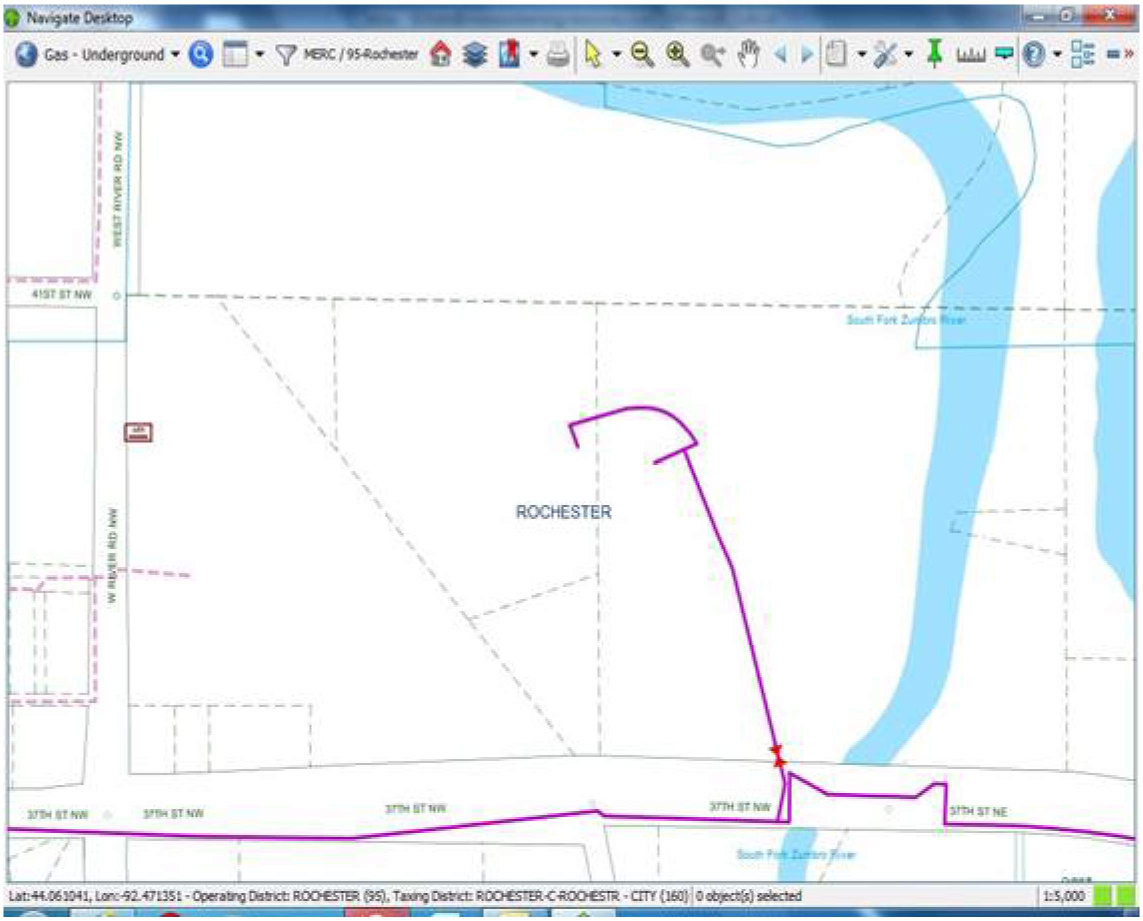
Thanks,
Nancy

From: Nancy Andrews
Sent: Tuesday, April 30, 2019 10:43 AM
To: paul.osullivan@minnesotaenergyresources.com; benjamin.wolf@minnesotaenergyresources.com
Subject: RE: Pipe to Waste Water Plant

Paul and Ben-

Thanks for your time this morning.

The map below and the emails were my previous contacts about the NG pipeline.



From: Shreve, Stanley P <SPShreve@minnesotaenergyresources.com>
Sent: Tuesday, March 07, 2017 10:11 AM
To: Nancy Andrews <NAndrews@brwncald.com>
Subject: RE: Pipe to Waste Water Plant

Okay, I will see what engineering says. Thanks.

From: Nancy Andrews [mailto:NAndrews@brwncald.com]
Sent: Tuesday, March 07, 2017 8:52 AM
To: Shreve, Stanley P
Cc: Lenton, Rory D
Subject: RE: Pipe to Waste Water Plant

WARNING: This email was sent from an external address. Exercise caution when opening links or attachments.

Sorry, I should have been clearer about this. We would clean the gas to pipeline quality standards, including removing the CO_2 to make the BTU content equivalent. We spoke to MidAmerica about a similar project in Farmington and they were willing to accept it but they required a monitoring/metering assembly at the injection point to monitor gas quality. This is typically what we see for these biogas pipeline projects in other parts of the country.

From: Shreve, Stanley P [mailto:SPShreve@minnesotaenergyresources.com]
Sent: Tuesday, March 07, 2017 8:27 AM
To: Nancy Andrews <NAndrews@brwncald.com>
Cc: Lenton, Rory D <RDLenton@minnesotaenergyresources.com>
Subject: RE: Pipe to Waste Water Plant

I did just hear from engineering and they said because of the difference in BTU's between bio fuels and natural gas it would cause and issues and we would not want to do this. I will see about a map.

From: Nancy Andrews [mailto:NAndrews@brwncald.com]
Sent: Tuesday, March 07, 2017 8:14 AM
To: Shreve, Stanley P
Subject: RE: Pipe to Waste Water Plant

WARNING: This email was sent from an external address. Exercise caution when opening links or attachments.
Great, thanks, Stan. Is there any chance we could get a map of the pipelines in the vicinity that we could use for our discussion with the wastewater folks?

We would have something on the order of 200 scfm. Would the 2-inch be in the ballpark for that rate or would we need to go to a larger tie-in point?

If you hear anything over the next couple of days from your engineering folks about accepting biogas please pass it on.

Thanks again.

Nancy Andrews, PE (MN, IA, OH, MA)
Brown and Caldwell
nandrews@brwncald.com
T 651.468.2043 | **C** 612.306.9817

From: Shreve, Stanley P [mailto:SPShreve@minnesotaenergyresources.com]
Sent: Tuesday, March 07, 2017 8:06 AM
To: Nancy Andrews <NAndrews@brwncald.com>
Subject: Pipe to Waste Water Plant

Hi Nancy,

We have a 2 inch main with a pressure of 60lbs. that runs to the waste water plant. Good luck.

Stan

Stan Shreve

Minnesota energy Resources
Operations Manager - SE MN Region
507-529-5118
507-250-3726 cell
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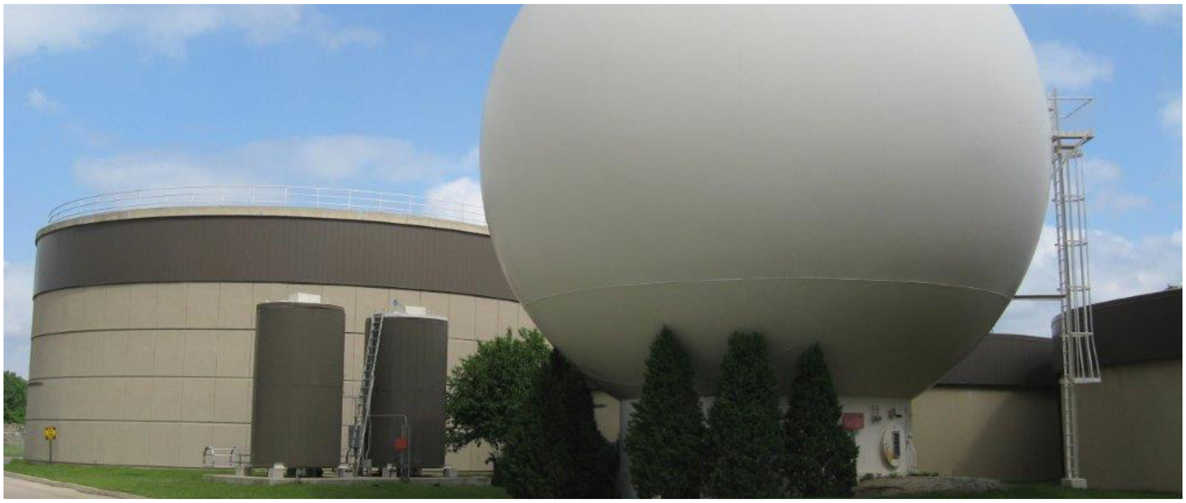
LOWER ENERGY // CLEAN DESIGN

DECREASED MAINTENANCE // INNOVATIVE PROCESSES



Technical Memorandum 1	Influent Flows and Loadings
Technical Memorandum 2	Wastewater Characterization and BioWin Calibration
Technical Memorandum 3	Plant Hydraulic Evaluation
Technical Memorandum 4	Primary Clarifier Computational Fluid Dynamics Modeling
Technical Memorandum 5	Final Clarifier Computational Fluid Dynamics Modeling
Technical Memorandum 6	Liquid Stream Alternative Evaluation
Technical Memorandum 7	Solids Alternative Evaluation
Technical Memorandum 8	Digester Gas Management
Technical Memorandum 9	Disinfection and Outfall Evaluation
Technical Memorandum 10	Whole Plant Evaluation
Technical Memorandum 11	Heat Recovery Loop Alternative
Technical Memorandum 12	NPDES Permitting Process
Technical Memorandum 13	Industrial Discharge Wasteloads and Practices