MWH

Prepared for

City of Tampa

Howard F. Curren AWTP
Biogas Use Study

JUNE 2013

PROFESSIONAL ENGINEER

The engineering features of the ***Biogas Use Study*** for the City of Tampa, June 2013 were prepared by, or reviewed by a Licensed Professional Engineer in the State of Florida.

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Executive Summary

The City of Tampa requested that MWH assist them in determining the future of their biogas power generation facilities with a focus on the following items:

- How to best utilize the biogas produced
- Potential cost savings for proposed biogas use alternatives
- Operational enhancement recommendations
- Environmental regulations

After examining plant data and meeting with plant staff MWH developed six preliminary biogas utilization alternatives. Of those six alternatives, three preferred alternatives were selected. The three preferred alternatives as well as two additional alternatives proposed by the City were compared in an economic analysis. The current system was also included in the comparison. The six alternatives compared were:

- Alternative No. 1 – New CHP engines with waste heat used to heat digesters.
- Alternative No. 3 – New CHP engines installed in TECO engine building, with exhaust waste heat to dryer to offset natural gas; and waste heat from dryer to heat digesters.
- Alternative No. 5 – All biogas to existing dryer facility and dryer waste heat recovery for digester heating.
- Alternative No. 5a – Biogas is used for heating the digesters and the remainder is fed to the existing dryer facility to offset some of the natural gas usage.
- Alternative No. 7 –Biogas is used for heating the digesters and the remainder is flared
- Current System – Continue operating the existing biogas engines over the design life of the project

MWH investigated environmental regulations associated with each of the possible alternatives and spoke with representatives of the Florida Department of Environmental Protection. It was determined that each of the proposed alternatives could be operated by modifying the plant's current air permit. It was also determined that the biogas engines currently in use at HFCAWTP could be run indefinitely under current regulations.

Background

The Howard F. Curren AWTP (HFCAWTP) is permitted for 96 million gallons per day (mgd) with current flows averaging between 50 and 60 million gallons per day (MGD). The biosolids handling facilities include gravity thickening of the waste activated sludge (WAS), anaerobic digestion, dewatering using belt filter presses, and sludge drying facilities for Class AA end product. The digester gas from the anaerobic digestion process is used for mixing the digesters, co-generation, and firing boilers for the digestion heating process during the winter months.

The plant currently has a Title V Air Permit for the internal combustion (IC) engines (engines used to produce electricity) with an expiration date of November 1, 2016. The current air permit states that the digester gas fueled engines must comply with the emissions standards of 40 CFR Subpart ZZZZ by October 19, 2013. However, because Subpart ZZZZ sets no emissions standards for existing digester fueled engines larger than 500 horsepower, there are no emissions requirements to meet and the current engines can remain in operation.

Economic Analysis and Recommendations

The economic analysis revealed that Alternative 1 is the most cost-effective biogas utilization alternative for the City of Tampa. The facilities and components of Alternative 1 are shown below. The capital cost of the recommended alternative is $8.6 million. The primary components of Alternative 1 include the following:

- Demolition of 5 existing 500 kW engines
- 3 new 1000 kW CHP engine packages
- Gas conditioning system to treat for siloxanes, moisture, and hydrogen sulfides
- Piping connections to new engines
- Instrumentation and control upgrades to be determined in final design

The capital investment of $8.6 million dollars will provide substantial benefit to the City when this project is compared to maintaining the current system. These benefits include:

- $151,822 decrease in labor costs annually
- $750,839 increase in revenue generated annually

When considering the benefits above as well as capital amortization period of 20 years, the recommended upgrades will yield approximately a $425,000 increase in net annual benefit (annualized benefits minus annualized costs) over the current biogas utilization system.

A recommendation for the phasing of this project is detailed in the **Table ES-1**.

Table ES-1: Summary of Recommended Improvements

Year	Components of Project	Capital Cost
Immediate	• New Biogas Conditioning System (Robinson Group or equal) • Demolition of existing biogas conditioning system	$2,587,000
FY 2014/15	• (1) 1000 kW CHP engine package (Waukesha APG 1000 or equal) • Biogas piping connections to new engine • Waste heat piping connections to new engine • Natural gas pipeline to existing generator building and connections to new engine • Demolition of (1) existing engine	$ 1,976,000
FY 2018/19	• (1) 1000 kW CHP engine package (Waukesha APG 1000 or equal) • Biogas piping connections to new engine • Waste heat piping connections to new engines • Natural gas piping connections to new engine • Demolition of (1) existing engine	$ 1,976,000
FY 2020/22	• (1) 1000 kW CHP engine package (Waukesha APG 1000 or equal) • Biogas piping connections to new engine • Waste heat piping connections to new engines • Natural gas piping connections to new engine • Demolition of 3 remaining existing engines	$ 2,084,000

Note: Capital costs are for 2013 and have not been increased due to inflation

1.0 Introduction

1.1 Background and Purpose

The Howard F. Curren AWTP (HFCAWTP) is permitted for 96 million gallons per day (mgd) with current flows averaging between 50 and 60 million gallons per day (MGD). The biosolids handling facilities include gravity thickening of the waste activated sludge (WAS), anaerobic digestion, dewatering using belt filter presses, and sludge drying facilities for Class AA end product. The digester gas from the anaerobic digestion process is used for mixing the digesters, co-generation, and firing boilers for the digestion heating process during the winter months. The hot water from the engine's cooling system is used as the primary heating source for the digestion system. The dryer facility utilizes rotary drum dryers and natural gas as fuel. Currently, the drying system is not operating and the dewatered sludge cake is hauled from the site for land application.

The plant currently has a Title V permit for the internal combustion (IC) engines (engines used to produce electricity) with an expiration date of November 1, 2016. The current air permit states that the digester gas fueled engines must comply with the emissions standards of 40 CFR Subpart ZZZZ by October 19, 2013. However, because Subpart ZZZZ sets no emissions standards for existing digester fueled engines larger than 500 horsepower, there are no emissions requirements to meet and the current engines can remain in operation.

The City of Tampa requested that MWH assist them in determining the future of their power generation facilities with a focus on the following items:

- How to best utilize the biogas produced
- Potential cost savings for proposed biogas use alternatives
- Operational enhancement recommendations

The purpose of this study is to identify the advantages and disadvantages associated with the proposed alternatives for the biogas usage as well as the net cost benefit. The investigation considered the technical viability, operational issues, and economic aspects of each alternative.

2.0 Current Biosolids Production and Handling

This section will present an overview of the biosolids production and handling at the HFCAWTP based on information provided by the City of Tampa. The information presented below is of relevance to the biogas study as biogas production is directly related to the quantity of biosolids generated and handled at the HFCAWTP.

2.1. Review of Plant Processes

The HFCAWTP currently operates as a High Purity Oxygen (HPO) facility with primary sedimentation, carbonaceous reactors, nitrification reactors, denitrification filters and disinfection facilities. **Figure 2-1** presents the HFCAWTP flow schematic. The current biosolids handling facilities include a thickening step for the waste activated sludge, mesophilic anaerobic digester for sludge stabilization, dewatering facilities, and a sludge drying facility.

Waste activated sludge comes from the carbonaceous reactors and is pumped from the plant pump station to two gravity thickeners for sludge thickening. Thickened waste activated sludge and primary sludge are pumped to a common wet well before being introduced to the anaerobic digesters for Class B sludge stabilization. The digested (stabilized) sludge is dewatered and then either hauled off site for land application or dried to produce a Class AA biosolids.

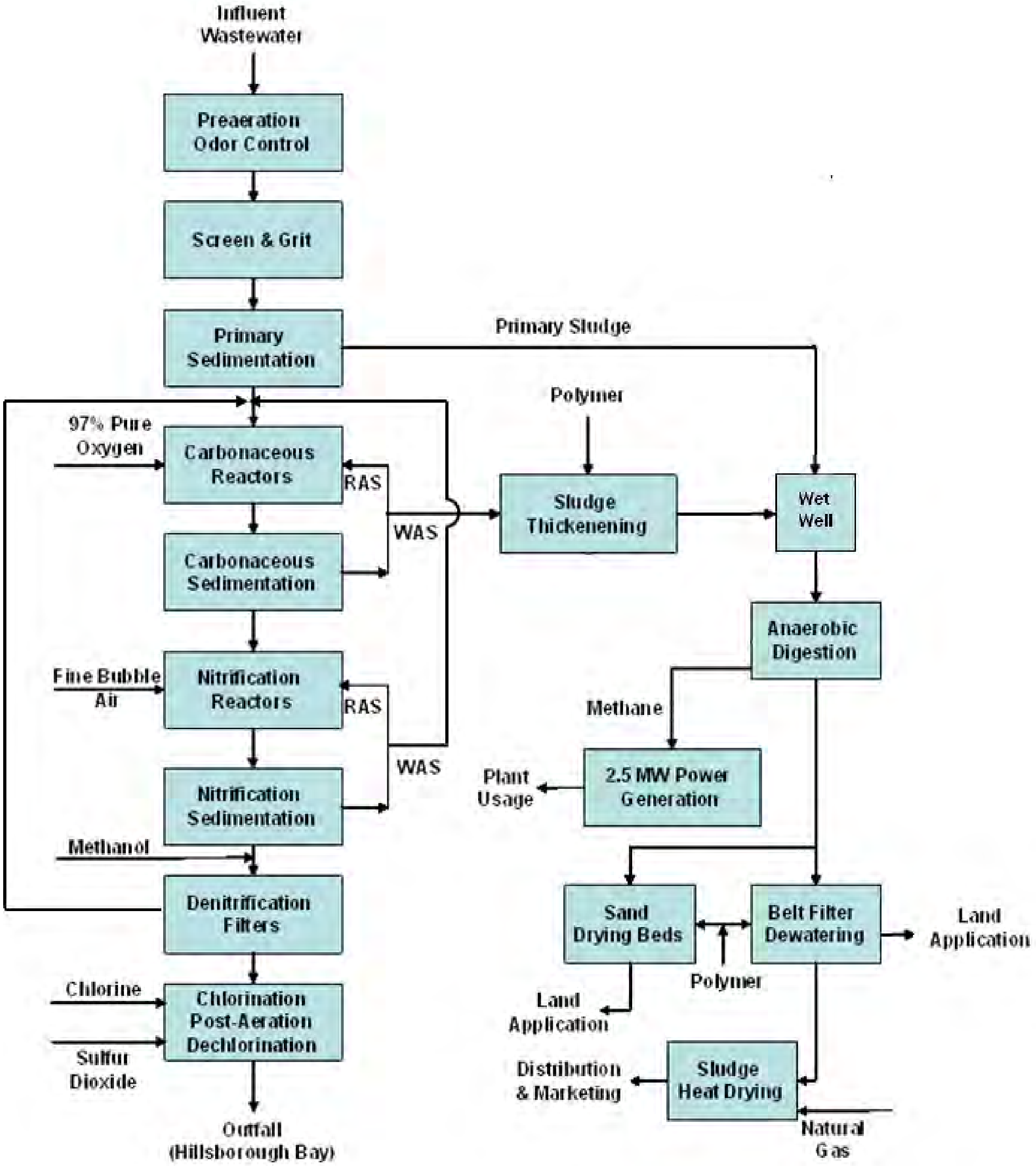


Figure 2-1: HFCAWTP Flow Diagram

2.2. Biosolids Quantity

Plant data from January 2005 to December 2011 was reviewed in an attempt to better understand the facility's overall treatment process and the biosolids produced. The liquid treatment process, and the sludge produced from those processes, affects the quality and quantity of the biosolids produced and must be considered when determining potential biosolids project alternatives utilizing gas production.

Influent wastewater flows including influent biochemical oxygen demand (BOD) and total suspended solids (TSS) loadings are summarized below in **Figure 2-2**. This data shows that the average BOD loading is approximately 86,400 lbs/day, and the average TSS loading is approximately 67,000 lbs/day. The following figure presents the HFCAWTP influent BOD and TSS loading.

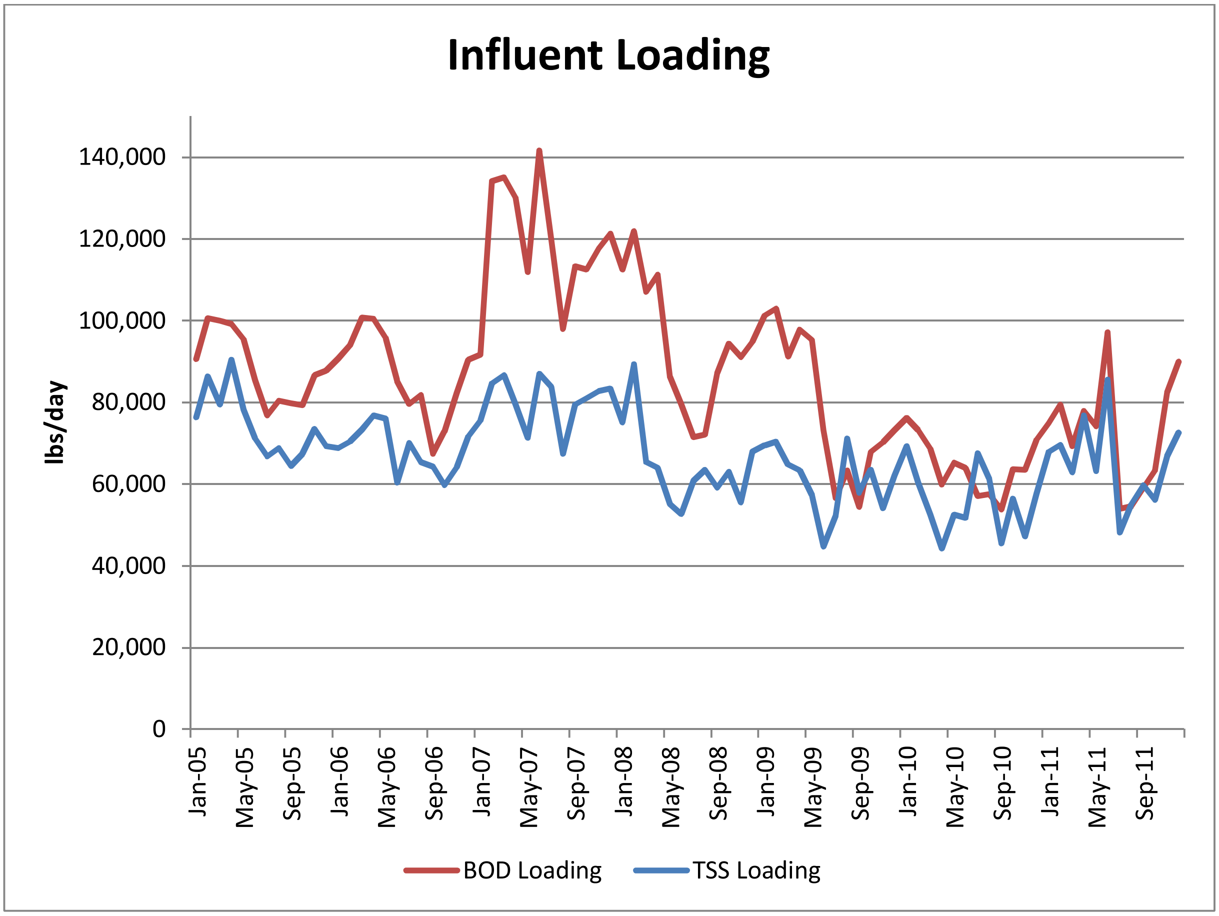


Figure 2-2: HFCAWTP Influent BOD and TSS Loading

The trend shows that the BOD and TSS loading to the HCAWTP have dropped by 12 and 17 percent, respectively, since 2005. The reason for this significant drop is unknown.

MWH also reviewed the sludge quantities produced during the 2005 to 2011 period. As discussed previously, the facility produces two main sludge streams: primary sludge and waste activated sludge. The quantities of these sludge streams are presented in **Figure 2-3** shown below

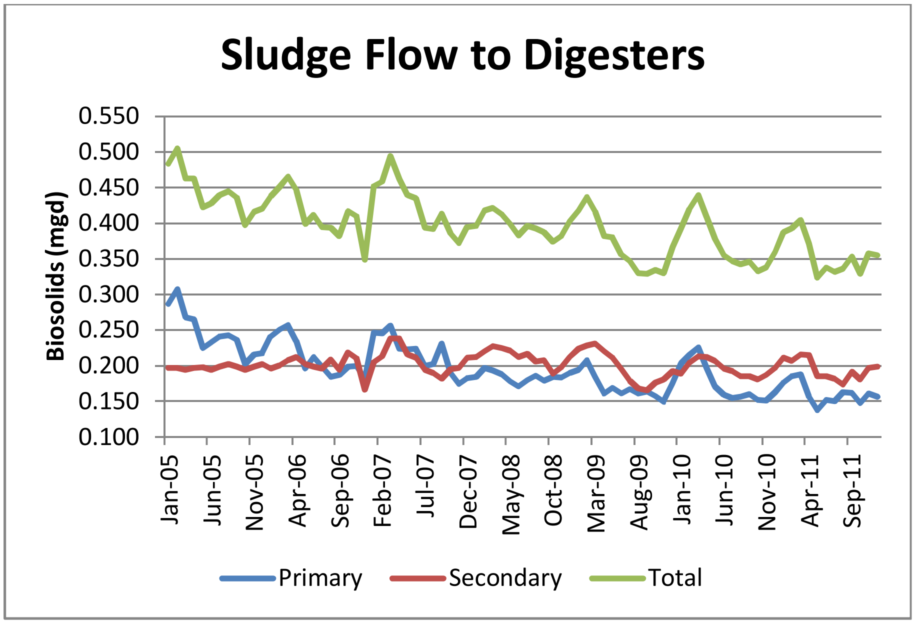


Figure 2-3: Sludge Flow to Anaerobic Digesters

A slight downward trend in production is noted and equates to an approximate 34 % reduction over that time frame. Based on conversations with the City, this trend is not expected to continue and sludge production will stabilize and may even increase based on wastewater flow projections due to population growth.

Volatile suspended solids (VSS) loading of the anaerobic digesters is shown in **Figure 2-4** as are the VSS as a percentage of the total suspended solids (TSS) in **Figure 2-5**. The average VSS loading is approximately 125,107 lbs/day and the average VSS percentage of TSS is roughly 84 %.

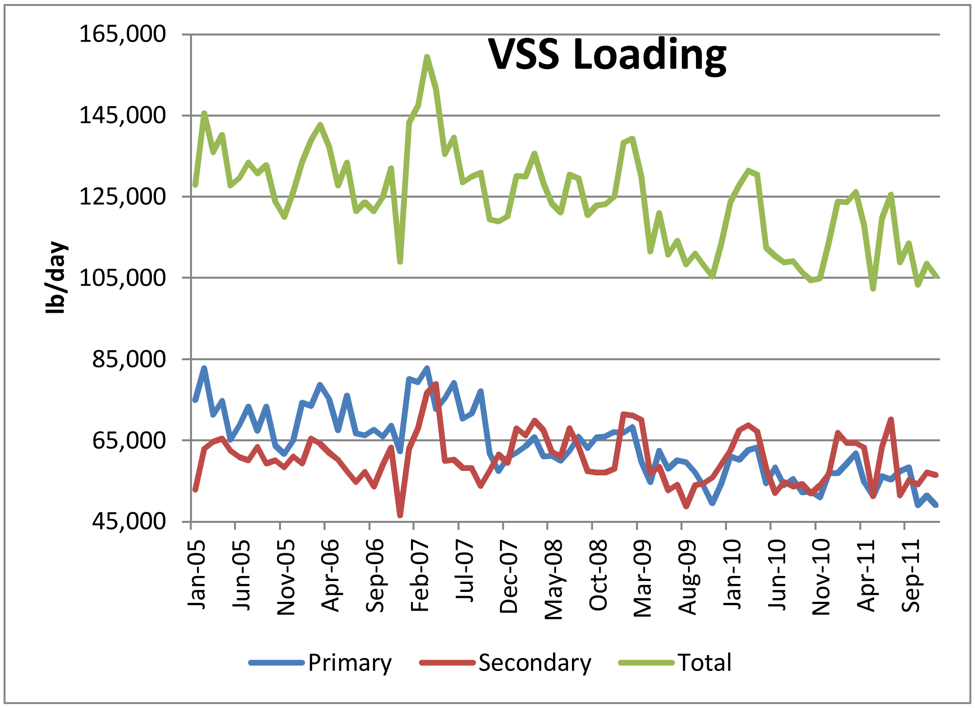


Figure 2-4: VSS Loading to Anaerobic Digesters

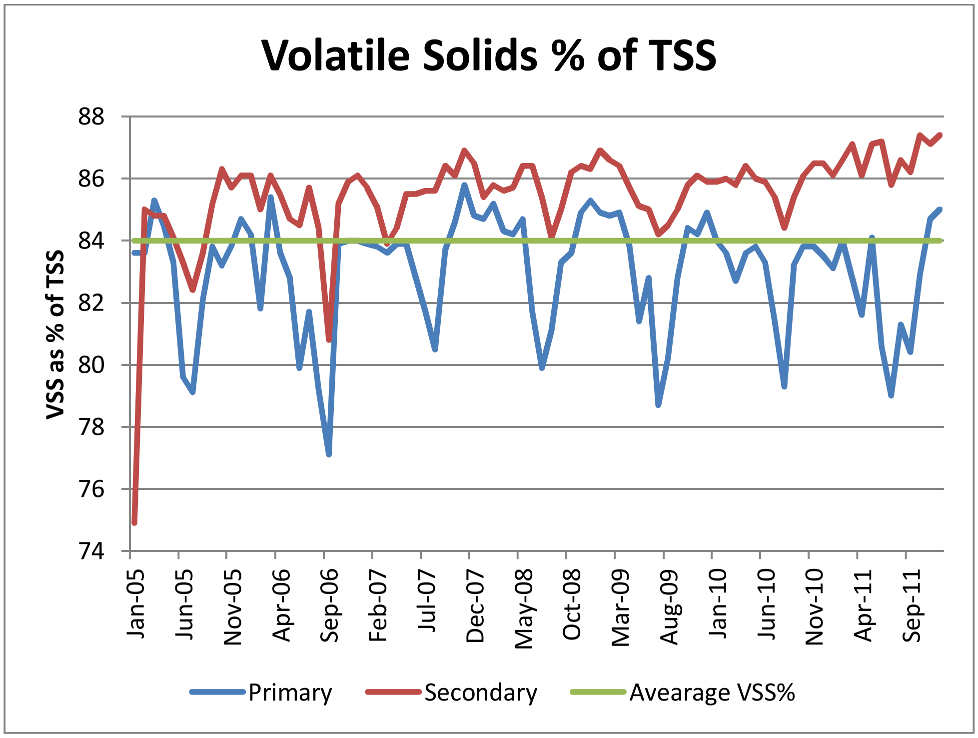


Figure 2-5: VSS Solids % of TSS

The average flow for industrial users from 2005 to 2011 is 1.6 MGD. The City of Tampa indicated that the industrial user loadings are expected to hold steady with no large users being added in the foreseeable future. The industrial users' loading is relatively small when compared with plant flow, TSS, and BOD loadings; however, their loading contribution is already accounted for in the figures presented above.

2.3. Biosolids Handling

As previously discussed; the biosolids generated at the HFCAWTP are stabilized to a Class B product using high rate, single stage, mesophilic anaerobic digesters. The stabilized digested sludge is dewatered and then either hauled off site for land application or dried by the facility sludge dryers. The following subsections present a brief review of equipment related to each of the biosolids processes as they relate to the biogas study.

2.3.1. Secondary Sludge Thickening

Waste Activated Sludge (WAS) is thickened by means of two gravity thickening tanks. The reported WAS thickened solids concentration averages 3.5%. This thickened WAS is piped to the Mixed Sludge Pumping Station and combined with the primary sludge. This sludge mixture is then pumped to the anaerobic digesters.

2.3.2. Digesters

There are seven existing anaerobic digestion tanks at the HFCAWTP. Volumes, sizes and roof types are indicated in **Table 2-1**, below. Digesters 1 thru 4 are located in a square pattern centered on Sludge Control Building A. Digester 5 is connected to Digester Control Building B and located south of digesters 1 thru 4. Digester 6 is east of digester 5 with digester 7 south of it. Digester Control Building C joins digesters 6 and 7. The seven digester tanks provide a total capacity of 9.8 million gallons (MG). On a site visit conducted June 12, 2012, digester number 6 was out of service for repair, thus reducing the total capacity by 2.45 MG. At the current time, Digester 6 has returned to service but Digesters 3 and 7 are out of service for repair work.

Table 2-1
Design Data for Existing Anaerobic Digesters

Digester Number	Diameter (ft)	Volume (gal)	Roof Type
1-3	75	837,760	Floating, gas holding
4	75	860,000	Floating, gas holding
5	95	1,600,000	Floating
6,7	110	2,450,000	Floating
Total	-	9,873,280	-

2.3.2.1 Heating

The cooling jacket water from the engines provides heat to the digestion system. The heated jacket water is pumped from the engines to heat exchangers within the digester control buildings. Each of the heat exchangers is rated for 2.0 million British thermal units (MBTU)/HR. The digesters operate with a target temperature of 97.5 degrees F and the jacket water system operates with a target temperature of 160 degrees F. Water boilers, fueled by biogas, are available when additional heat is required. The estimated heat produced from the engines and boilers is listed in **Table 2-2.**

Table 2-2
Heat produced by the IC engines and Boilers

	Size	Heat Production (MBTU/hr)
Engine 1	500 kW	1.5
Engine 2	500 kW	1.5
Engine 3	500 kW	1.5
Engine 4	500 kW	1.5
Engine 5	500 kW	1.5
Boiler 1	75 BHP	2.5
Boiler 2	75 BHP	2.5
Boiler 3	75 BHP	2.5
Boiler 4	75 BHP	2.5

Notes:

1. Engine #1 is out of service
2. BHP stands boiler horsepower. 1 BHP=33,475 BTU/hr

2.3.2.2 Mixing

The existing mixing system utilizes a confined gas mixing system in each of the 7 digester tanks. Digesters 1 thru 4 have four gas mixing tubes installed and digesters 5 thru 7 have six gas mixing tubes installed. Digester 4 currently only has two lances operating, but City staff reports that this has yet to cause any issues in the digestion process. Under normal operation, the gas mixing system runs continuously to provide the necessary mixing. This system has performed reasonably well but may not be the most efficient.

2.3.3. Dewatering/ Disposal

Sludge exiting the seven anaerobic digesters is pumped to the Sludge Dewatering Facility. Within the Sludge Dewatering Facility are eight belt filter presses which are used to dewater the digested sludge to 15-17% total suspended solids. The thickened sludge can then be hauled by truck for disposal or land application. The HFCAWTP also has a rotary drum dryer system that was installed in 1988 and is fueled by natural gas. Cake sludge processed in the two dryer trains is dried to roughly 96% solids and is classified as a Class A biosolid. The sludge drying system is currently not in service and requires extensive repair.

In March of 2012, Hazen and Sawyer recommended that the City invest $13.4 million through the 2014/2015 fiscal year to improve the dewatering facility and one of two existing dryer trains. Hazen and Sawyer also reported that an additional $3.8 million would need to be invested to make both dryer trains operational. The City has already committed capital funds to improve the dewatering process and facility, leaving a remaining cost of roughly $9.5 million to repair both dryer trains within the existing dryer facility.

3.0 Biogas and Energy Production

Anaerobic digestion is the decomposition of organic matter in the absence of oxygen. It is a three step process involving destruction of volatile solids, the production of organic fatty acids followed by conversion to methane, carbon dioxide, and trace gases. The methane forming bacteria are strictly anaerobic and are also the critical element in successful digestion. Biogas is a by-product of the decomposition of the organic material by the methane forming bacteria. In many facilities, such as the City of Tampa's HFCAWTP, biogas is used as fuel to produce electricity.

This section will present the review MWH completed for the City of Tampa's HFCAWTP biogas production and the energy available from it.

3.1 Biogas Production

Biogas is produced as volatile suspended solids (VSS) are destroyed. **Figure 3-1** below, presents the VSS destruction results from 2005 to 2011 as provided by the City.

The average VSS destruction is 53% with a maximum monthly daily average of 60% destruction. These are very typical destruction rates for high rate mesophilic anaerobic digesters.

Figure 3-2 shows the reported quantity of total monthly biogas produced at HFCAWTP from 2005 to 2011.

The graph shows a downward trend (30 percent drop) in biogas production over the last 7 years. The average value dropped from 27.8 million cubic feet per month to 21.9 million cubic feet per month. It is important to note that even though there are three gas meters at the engine building, none of these meters are used to measure biogas flow. The City indicated that the biogas production presented above is calculated based on the engine runtime. Each engine has a known fuel (biogas) consumption rate. This value is multiplied by the total runtime during the day to estimate the biogas produced per day.

The reported downward trend in biogas production has two feasible explanations. The first is that the downward trend in BOD entering the plant, as shown in Figure 2-2, is related to a downward trend in sludge loading and, therefore, lower biogas production.

Another reason for the downward trend in biogas could also be attributed to a leak in the engine jacket water pipe. As biogas production is calculated by engine run time, the leak in the engine jacket water pipe forced the City to run the biogas-fueled hot water boilers to make up the hot water that was leaked. This would have diverted biogas from the engines and caused a decrease in the reported biogas production. The City is currently replacing the leaking engine jacket water pipe.

Figure 3-3 presents the reported rate of cubic feet of biogas produced per pound of VSS destroyed (cu.ft/lb VSS). The HFCAWTP reported average rate of production is 12.6 cu.ft/lb VSS destroyed based on back calculations using engine run time, and does not take into account biogas use in boilers. This number appears low based on industry standard and the literature values for a high rate mesophilic anaerobic digester is 15-18 cu.ft/lb VSS destroyed. Given the discrepancies in the calculated biogas production rate, a conservative value of 15 cu.ft//lb VSS destroyed will be used for this report.

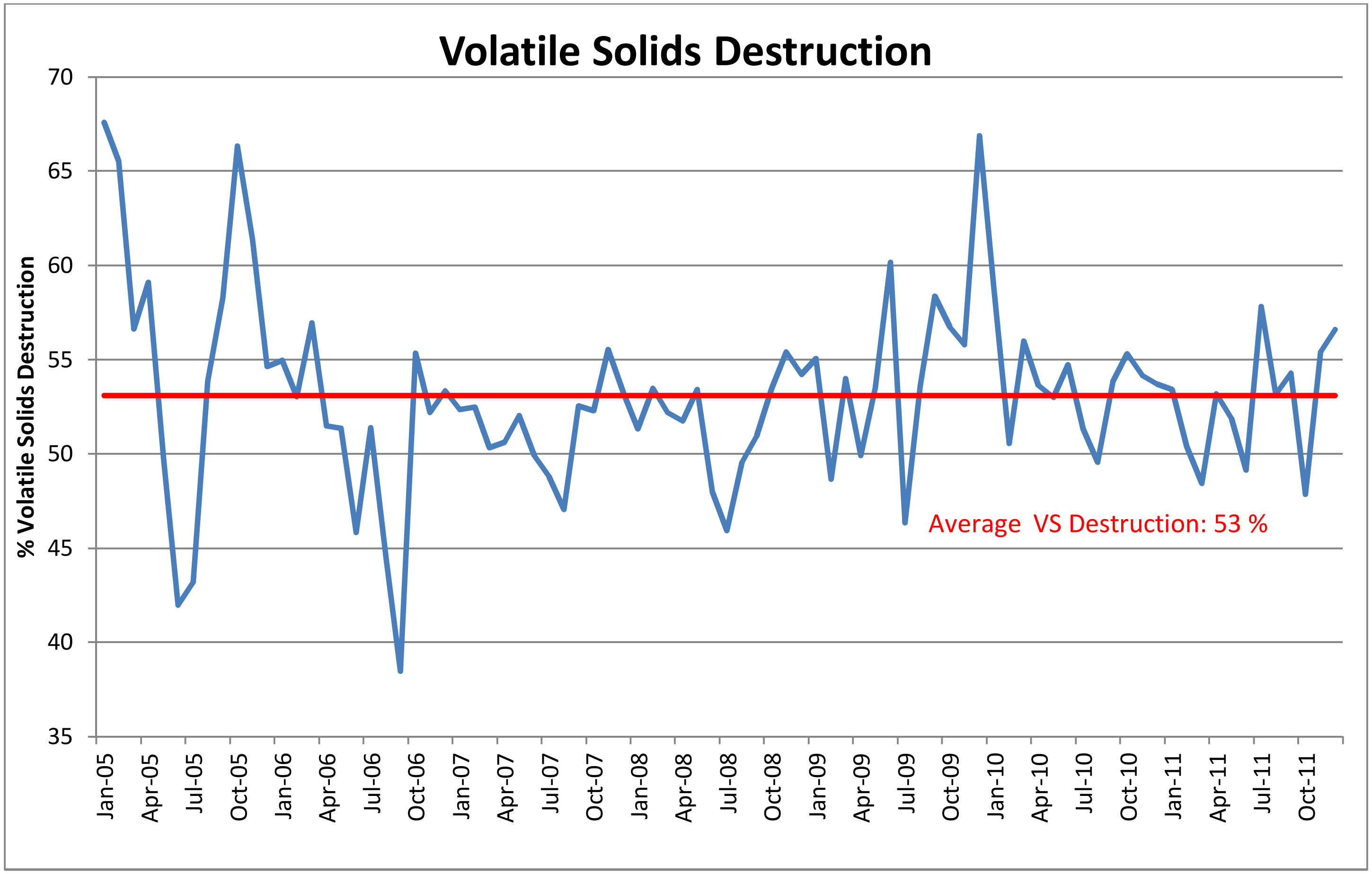


Figure 3-1: VSS Destruction Rate from 2005 to 2011

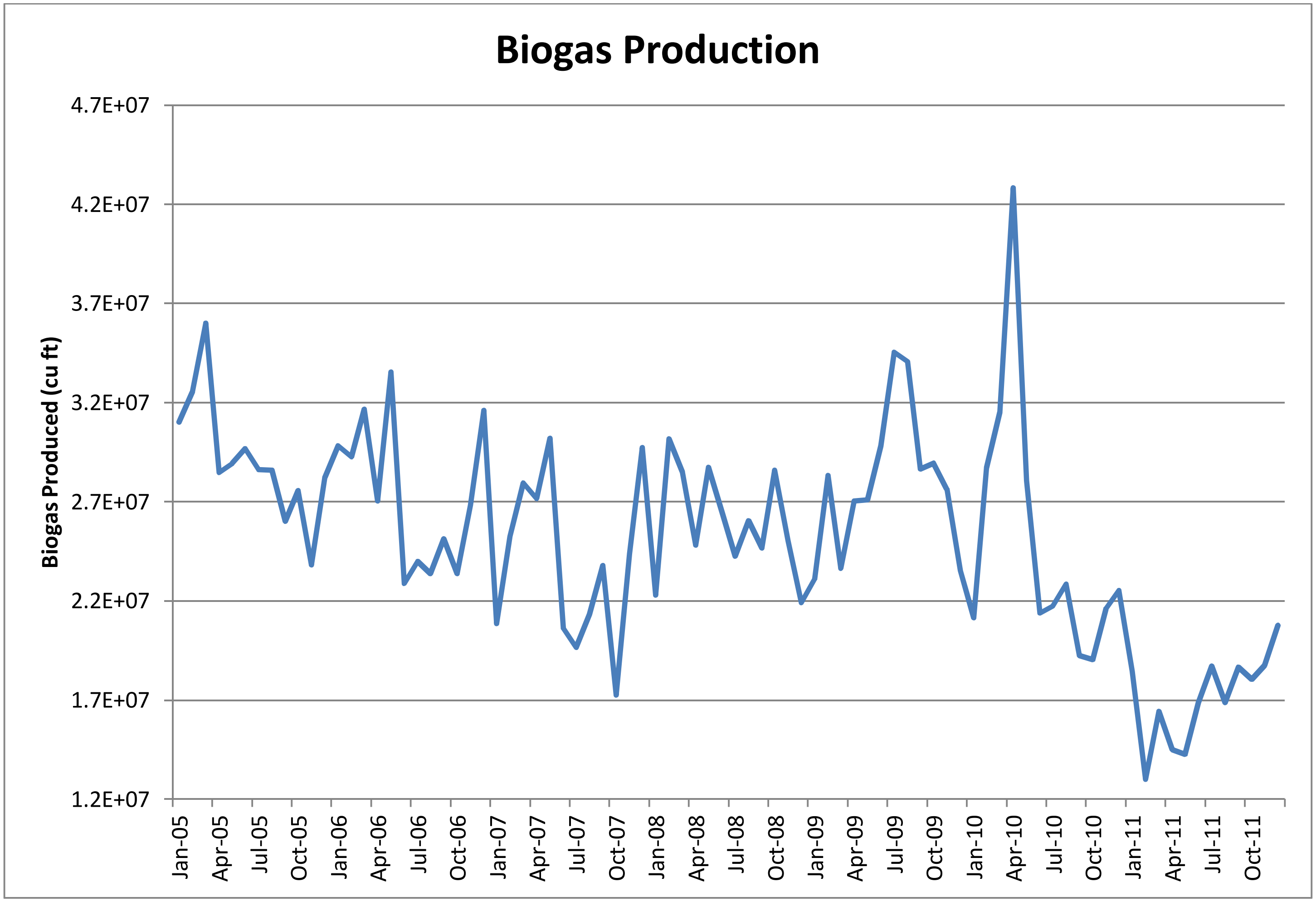


Figure 3-2: Monthly Biogas Production from 2005 to 2011

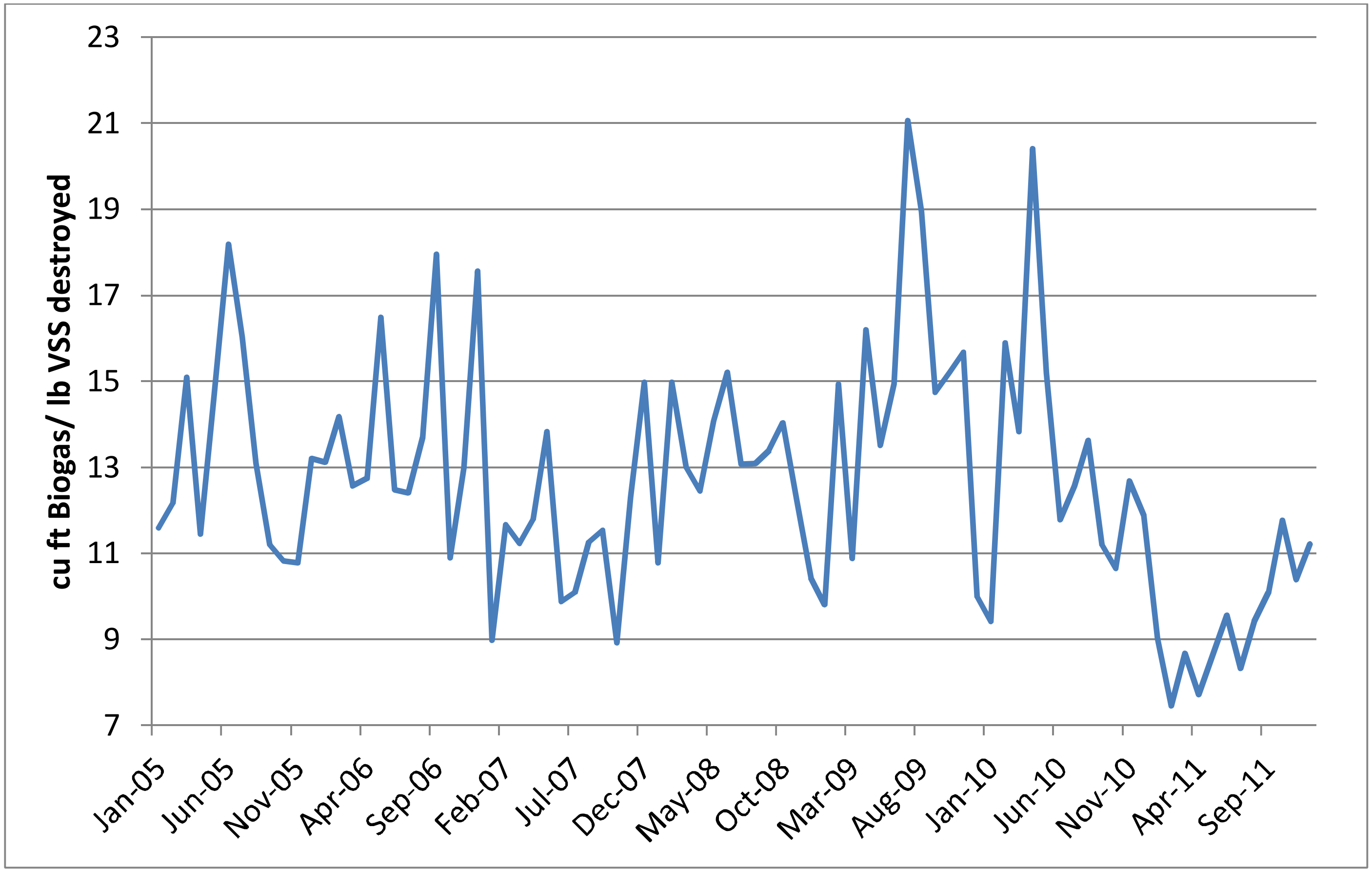


Figure 3-3: Cubic Feet of Biogas per VSS Destroyed from 2005 to 2011

3.2 Biogas Quality

On December 11, 2012, samples of biogas were taken at the HFCAWTP and tested for: major gas constituents, gross heating value, siloxanes, sulfur compounds, and volatile organic compounds. Samples were taken from the biogas system both upstream and downstream of the filter units, in order to provide the City with information on how well the current biogas conditioning system operates. **Table 3-1** presents a summary of testing results that are used to determine biogas quality and potential treatment options when utilizing biogas in engines, complete results are available in **Appendix A**.

Table 3-1
Biogas Testing Results (from December 11, 2012 sampling)

Parameter	Units	Upstream of Filters	Downstream of Filters
Carbon Dioxide	%	36.3	35.9
Methane	%	54.4	52.0
Nitrogen	%	7.64	8.90
Oxygen	%	1.60	3.21
Gross Heating Value	BTU/ft^3	550	525
Total Siloxanes	ppbv	1,270.1	1,614.6
Hydrogen Sulfide	ppbv	68,900	135,000

The concentrations shown in Table 3-1 for the biogas upstream of the existing filters at HFCAWTP are very typical of anaerobically digested wastewater sludge. The methane concentration of 54.4% is slightly lower than the typical 60%. The lower methane content leads to a slightly lower heating value as well, the 550 BTU/ft^3 value reported is under the industry standard of 600 BTU/ft^3.

Table 3-1 shows that hydrogen sulfide and siloxane concentrations are higher downstream of the biogas filter units, this increase in concentration is caused by what is called the “roll-over” effect. The filter units at HFCAWTP purge sulfur compounds (hydrogen sulfide) and siloxanes, which have smaller molecular weights, as they fill with the siloxanes that have high molecular weights. This purging creates higher concentrations of siloxanes and hydrogen sulfide down-stream of the existing filter units.

3.3 Energy Production

The amount of energy produced at the HFCAWTP is directly related to the quantity of biogas and the heating value of the biogas. The quantity of biogas available is directly related to the amount of volatile solids destroyed. As described in Section 2, the average VSS loading to the HFCAWTP is 124,000 lbs/day. For purposes of this report, the average biogas heating value and the biogas production rate at the HFCAWTP is assumed at 550 BTU/ft^3 as indicated by the biogas testing results and 15 ft^3/ lb VSS destroyed.

Using an average heating value of 550 BTU/ft^3 will provide a conservative estimate, as this value is from a single sample taken at HFCAWTP. Industry standard typically assumes a heating value of approximately 600 BTU/ft^3.

Table 3-2 shows the amount of biogas produced and the energy available in the biogas at the HFCAWTP.

Table 3-2
Biogas Produced and Energy Available

Parameter	Value
Average VSS loading (lbs/day)	124,000
Average VSS destroyed (lbs/day)	66,409
Volume of biogas per pound of. VSS destroyed (ft^3/lb VSS)	15
Volume of biogas (ft^3)	996,136
MBTU/hr Biogas	22.8

1. Average VSS destruction is 53%
2. Average biogas heating value is 550 MBTU/ft^3

3.3.1 Energy Requirements

The energy required to operate and maintain the digestion system at the HFCAWTP was calculated. Only two seasonal needs (winter energy demands and summer energy demands) were evaluated for this study.

The energy demands for the anaerobic digestion system at the HFCAWTP are summarized in **Table 3-3** below. A table providing the breakdown of heating requirements can be found in **Appendix B**.

The total energy required to maintain and operate the digestion system at the HFCAWTP is approximately 7,981,952 and 4,274,987 BTU/hr during the winter and summer months, respectively. **Figure 3-4** shows the biogas energy available versus the seasonal digester operational heating/energy demands. It is important to note that an excess of 16.92 and 20.63 MBTU/hr is available during the winter and summer months, respectively.

Table 3-3
Anaerobic Digester Heating Parameters

Parameter	Units	Summer months	Winter months
Temperature of residuals	degrees F	83	75
Sludge desired temperature	degrees F	98	
Sludge flow	mgd	0.45	
Heat required to raise residual temperature to desired temperature	BTU/hr	2,720,925	4,222,125
Total heat required (including all local losses)	BTU/hr	4,274,987	7,981,952

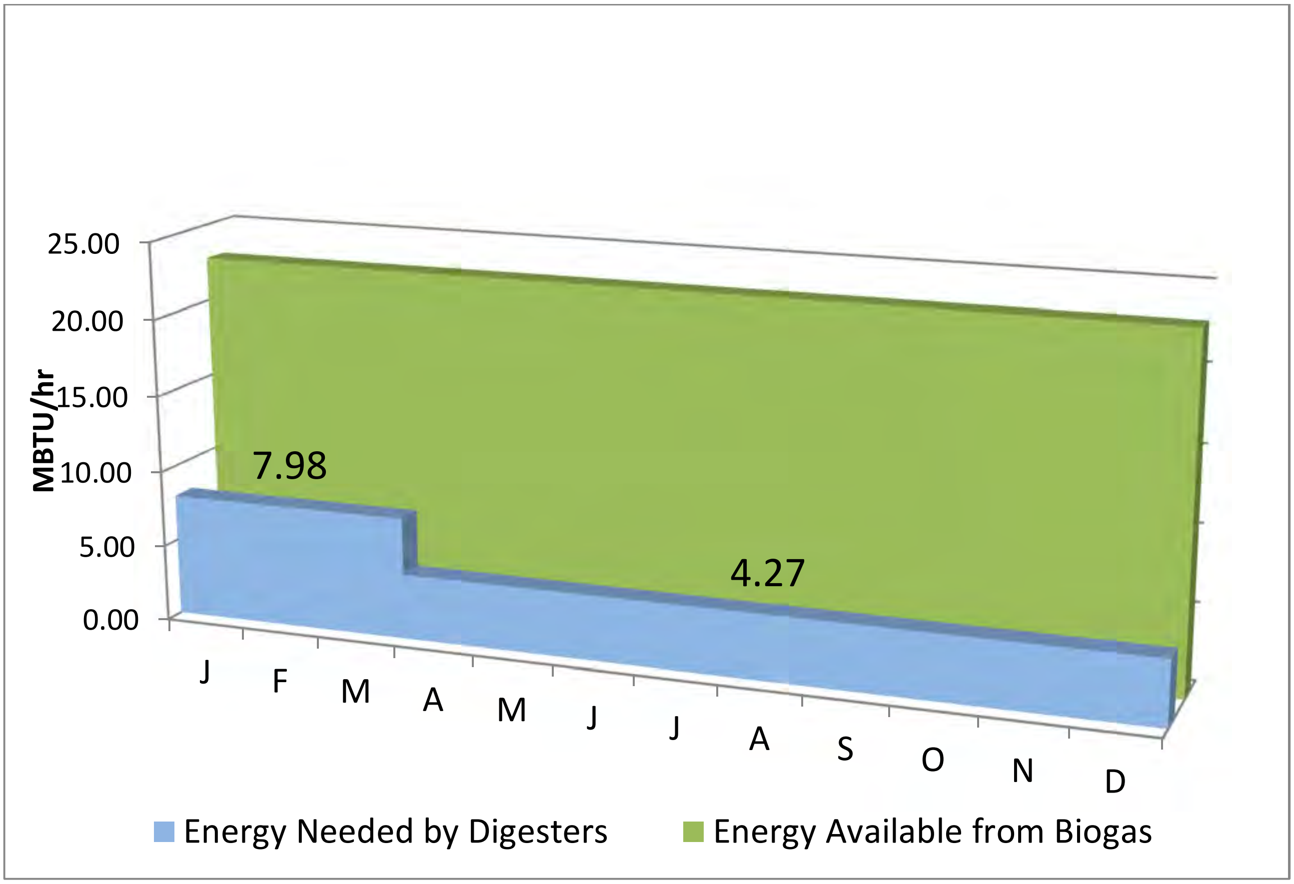


Figure 3-4: Available Energy and Anaerobic Digestion System Energy Needs

4.0 Current Biogas Utilization

The biogas is currently utilized at the HFCAWTP to produce electricity with five internal combustion engines and to fuel hot water boilers during the winter months. This section provides a detailed description of the current power generation facilities and the current biogas utilization at the HFCAWTP.

4.1 Biogas Handling Facilities

4.1.1 Storage

Most of the biogas produced at the HFCAWTP is stored in the floating, gas holder type covers, for digester Nos. 1 thru 4. Each gas holder cover is capable of storing approximately 22,500 cubic feet of biogas providing a total storage capacity of 90,000 cubic feet of biogas. This limited storage capacity is used to build biogas reserves during non-peak hours so that the maximum electricity production is done during peak hours.

4.1.2 Pressurization/Conveyance

Biogas from each of the digester covers is withdrawn from each of the digesters via an 8-inch ductile iron pipe. As illustrated in **Figure 4-1**, the biogas is conveyed through sediment traps for moisture removal, and compressed before being used as fuel by the engines.

Biogas is pressurized by 5 rotary positive displacement compressors (**Figure 4-2**). There is one compressor for each of the biogas fueled engines. Biogas is withdrawn from the digesters, conveyed through condensate tanks and filters, and compressed into a common discharge header piped to the engines. There are biogas flow meters to measure the biogas flow to Engine Nos. 3 to 5, but none for Engine Nos. 1 and 2.

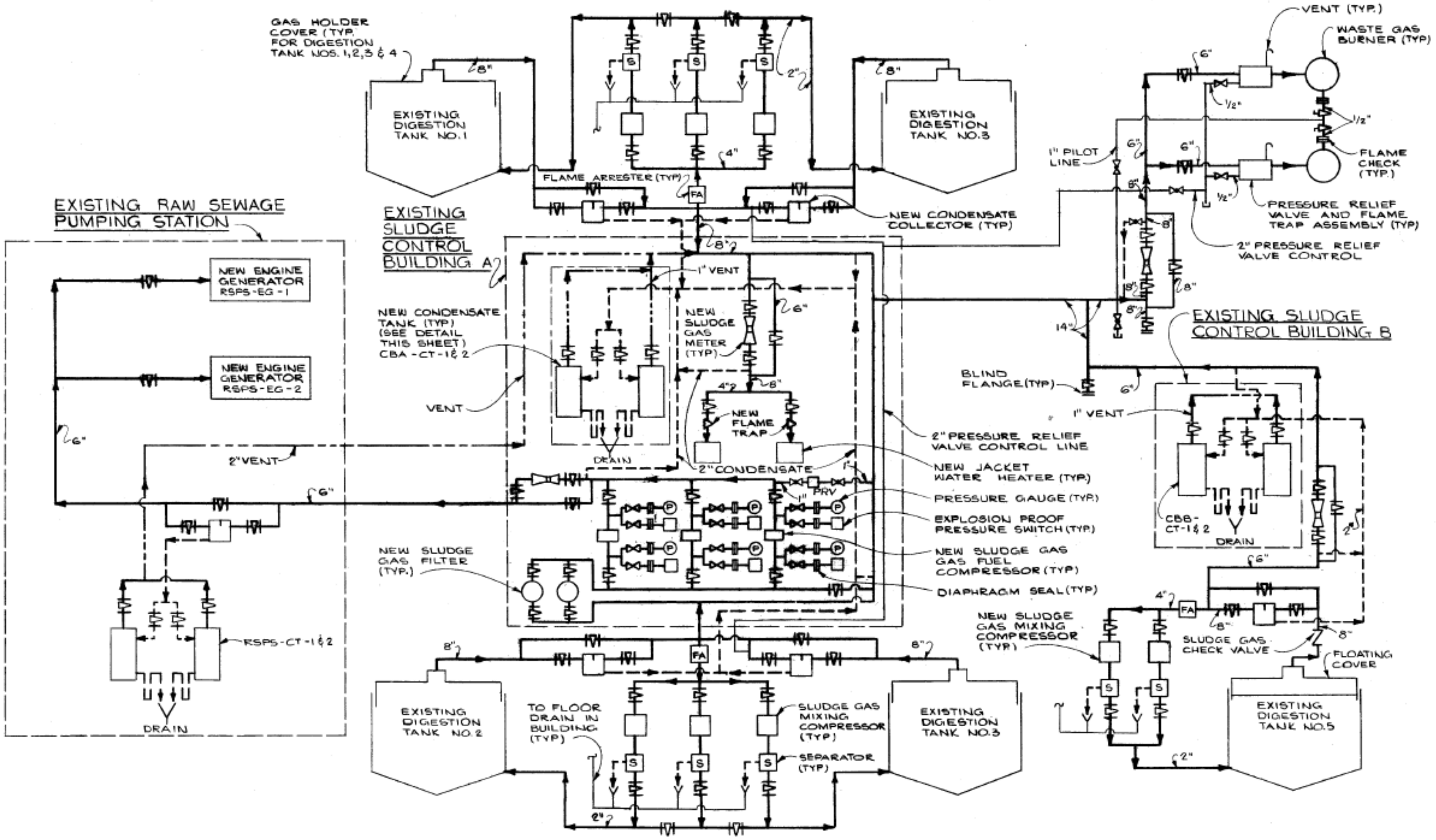


Figure 4-1: Biogas Piping Schematic (from Plant Record Drawings)

Figure 4-2: Biogas Compressors

4.1.3 Treatment/Conditioning

The HFCAWTP currently uses a biogas conditioning filter that neutralizes the dissolved sulfur compounds in the biogas to allow its use as engine fuel. The filter media consists of highly cellular organic fibers treated with an alkaline chemical combined with flocculating agents. The fiber treatment promotes the formation of a crystal surface providing a contact area for radical organic mercaptans (sulfur compounds). These mercaptans react with the crystals and satisfy the free radicals (neutralizing) so they do not react as a radical in the presence of water formed during the burning phase. Free radicals typically attack the engines' internal and external components during the burning phase.

The filters are located in 8 separate 48-inch vessels, each with 69 replaceable filter elements (see **Figure 4-3**).

Figure 4-3 - Biogas Conditioning Filter

The biogas moisture is removed via condensate/sediment removal traps and pressurized condensate units. **Figure 4-4** and **Figure 4-5** show a photo and cross section of a typical sediment and condensate removal trap. Sediment and condensate removal traps are designed to remove large volumes of water that condense when the biogas cools as it exits the digesters. Sediment that is entrained in the biogas will drop out and accumulate in the trap, protecting downstream equipment from damage caused by solids.

The condensate/sediment removal traps are equipped with a large reservoir with an inlet flange designed to swirl the biogas and an internal baffle located at the base of the reservoir to provide efficient separation of solids.

Figure 4-4: Biogas Condensate/Sediment Trap

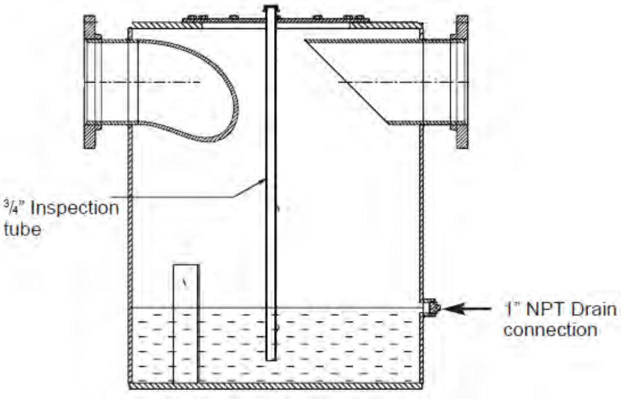


Figure 4-5: Biogas Condensate/Sediment Trap Section (courtesyof Varec Inc.)

Additional biogas moisture is removed, immediately upstream of the engines, by pressurized condensate units. The biogas is pressurized to a predetermined pressure, allowing the condensation of water. **Figure 4-6** shows a photo of a pressurized condensate unit.

Figure 4-6: Pressurized Biogas Condensate/Sediment Trap

4.1.4 Condition Assessment

The biogas handling system is in need of some repairs. Biogas is leaking at certain areas, especially around the digester mixing equipment. The pipe joints should be repaired to seal these leaks.

The biogas flow meters are out of service and some are missing (i.e., flow meter to Engine Nos. 1 and 2). The biogas compressors were observed to be in good condition. No excessive vibration or unusual noises were noted on the compressors.

As discussed in Section 3.2, the current biogas conditioning system is highly inefficient. The Plant operations staff has complained about the quality of the biogas used to fuel the engines. Excessive moisture, white deposits on the engine pistons (siloxanes), and corrosion have been observed on the engine system. It is highly recommended that a new biogas conditioning system targeting hydrogen sulfide, moisture, and siloxanes be installed at the HFCAWTP.

4.2 Engines

The HFCAWTP currently has five engines. **Table 4-1** lists specifications for each of the engines.

Table 4-1
Engine Specifications

	Model	Size	Manufactured	Location
Engine 1	Waukesha VHP-L7042 GU	500 kW	1984	Raw Sewage Pumping Station
Engine 2			1984	
Engine 3			1984	Generator Building
Engine 4			1984	
Engine 5			1987	

In the current operational scheme, all available engines are operated during peak hours, from noon until 9 P.M. Outside of peak hours the engines are shut down and biogas is stored until the next peak period. Energy produced during peak hours at the HFCAWTP is purchased at a higher rate by TECO thus creating a greater offset to operating costs at the HFCAWTP.

4.2.1 Condition Assessment

The HFCAWTP biogas fueled engines are old and in need of repairs/ replacement. Engine No. 1 is out of service and in need of major repairs (Figure 4-7). The City indicated that the estimated repair costs for this engine is $100,000.

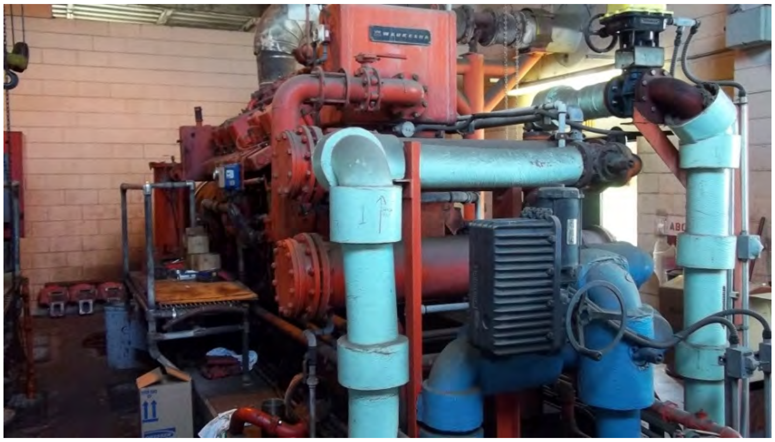


Figure 4-7: IC Engine No. 1

Engine Nos. 2, 3, 4 and 5 are currently in operation. Engine operators have indicated that the maintenance of these biogas fueled engines is very labor intensive and time consuming due to the poor condition of the engines. Engine operators have reported that the engines require oil replacement every 500 hours, when the engine manual indicates that the oil should be replaced every 1,500 hours.

4.3 Heat Recovery System

Waste heat is recovered from the engines and used to provide heat to the anaerobic digestion system. Mounted on each of the five engines are heat exchangers to transfer the waste heat from the engine to the jacket water loop to provide heat to the digesters. Within the jacket water loop are eight 300 GPM pumps. Jacket water pumps 1 through 3 are located in the basement of the raw sewage pumping station, underneath engines 1 and 2. Jacket water pumps 4 thru 8 are located in the generator building in a room adjacent to engines 3 thru 5.

In the event that additional heat is needed for the digestion system, there are four 76 HP water boilers integrated into the heating loop. The Bryan Flexible Tube Boilers are fueled by biogas and can produce between 1280 and 2560 MBH. Additional heat is typically only required during winter months.

4.3.1 Condition Assessment

A site visit on June 12, 2012, revealed that the original design would allow for engines 3 thru 5 to provide heat to digesters 6 and 7 and engines 1 and 2 to provide heat for digesters 1 thru 5. There is a cross-connection between these two systems which is open. The connection of the two loops can be verified through water losses seen in the entire jacket water system due to a leak near jacket water pumps 4 thru 8. The existence of this cross-connection makes it difficult to control temperatures for the individual heat exchangers as there is no secondary loop in the heating system.

During the same site visit, operations personnel indicated that one boiler is operated outside of the typical winter months because digester number 3 has difficulty maintaining the target operating temperature. The additional heat is required to elevate the temperature of digester number 3 to allow for proper digestion, it is believed that this problem is due to a clog in the heat exchanger.

5.0 Biogas Utilization Alternatives

As indicated in Section 3.0 abundant energy is available in the biogas produced by the HFCAWTP. The City has utilized some of this energy to produce electricity. However, concerns about the cost to operate the engines, new regulations, and the age of the existing equipment have led the City of Tampa to evaluate alternatives for the utilization of the biogas at the HFCAWTP. Initially six biogas utilization alternatives were developed using the information presented in Section 3.

This section will present feasible biogas utilization alternatives that are applicable to the City of Tampa. These alternatives are evaluated with the following considerations:

- Financial benefits (business case)
- Beneficial use of existing equipment
- Amount of energy provided
- Site constraints
- Technical viability and,
- Operational issues

5.1 Initial Biogas Utilization Alternatives

Six alternatives were developed and presented to the City in an initial screening workshop. The alternatives are:

- **Alternative No. 1-** New combined heat and power (CHP) engines with waste heat used to heat digesters
- **Alternative No. 2-** New CHP engines with waste heat used to heat digesters and excess waste heat utilized in absorption chillers
- **Alternative No. 3**- New CHP engines installed in TECO engine building, with waste heat to dryer to offset natural gas; and waste heat from dryer to heat digesters
- **Alternative No. 4**- New CHP engines installed at existing engine building with waste heat to new dryer to offset natural gas; and waste heat from new dryer to heat digesters
- **Alternative No. 5**- All biogas to existing dryer facility
- **Alternative No. 6**- All biogas to new dryer facility and dryer waste heat used for digester heating

For each of the alternatives listed above, a more detailed overview is provided in the following sections. Those alternatives that include the use of biogas fueled engines include a biogas conditioning component. Biogas conditioning is required for the engine alternatives as it will provide the quality of fuel needed by the engines to maximize efficiency and reduce maintenance requirements. Alternatives that involve the direct burning of biogas, i.e. flaring or dryer fueling do not require biogas conditioning as it provides limited operational benefit.

5.1.1 Alternative 1 - Replace existing engines with new CHP engines with waste heat used to heat digesters

Alternative No. 1 consists of installing three new 1,000 kW internal combustion (IC) engines with combined heat and power (CHP) packages in the existing generator building. The waste heat from the engines will be utilized to heat digesters and the excess engine waste heat will be wasted. **Figure 5-1** shows a schematic of the energy balance for Alternative 1. The advantages, disadvantages, and the primary components of Alternative 1 are listed in **Table 5-1**.

Table 5-1
Primary Components and Advantages and Disadvantages for Alternative No. 1

Alternative 1- Replace existing engines with new engines with waste heat used to heat digesters	
Primary Components	**Advantages**
• Demolition of existing engines • New CHP engine packages with exhaust heat exchangers • Gas conditioning/cleaning • Waste heat recovery system • Switchgear/electrical systems • Instrumentation/control	• Increased power production • Full utilization of all biogas • Eliminates or reduces the use of the biogas in hot water boilers. • Familiarity with operation • Lower maintenance costs
	Disadvantages
	• Not utilizing all waste heat • Does not offset natural gas use in dryer • Gas conditioning and treatment need to be provided. • Requires capital investment

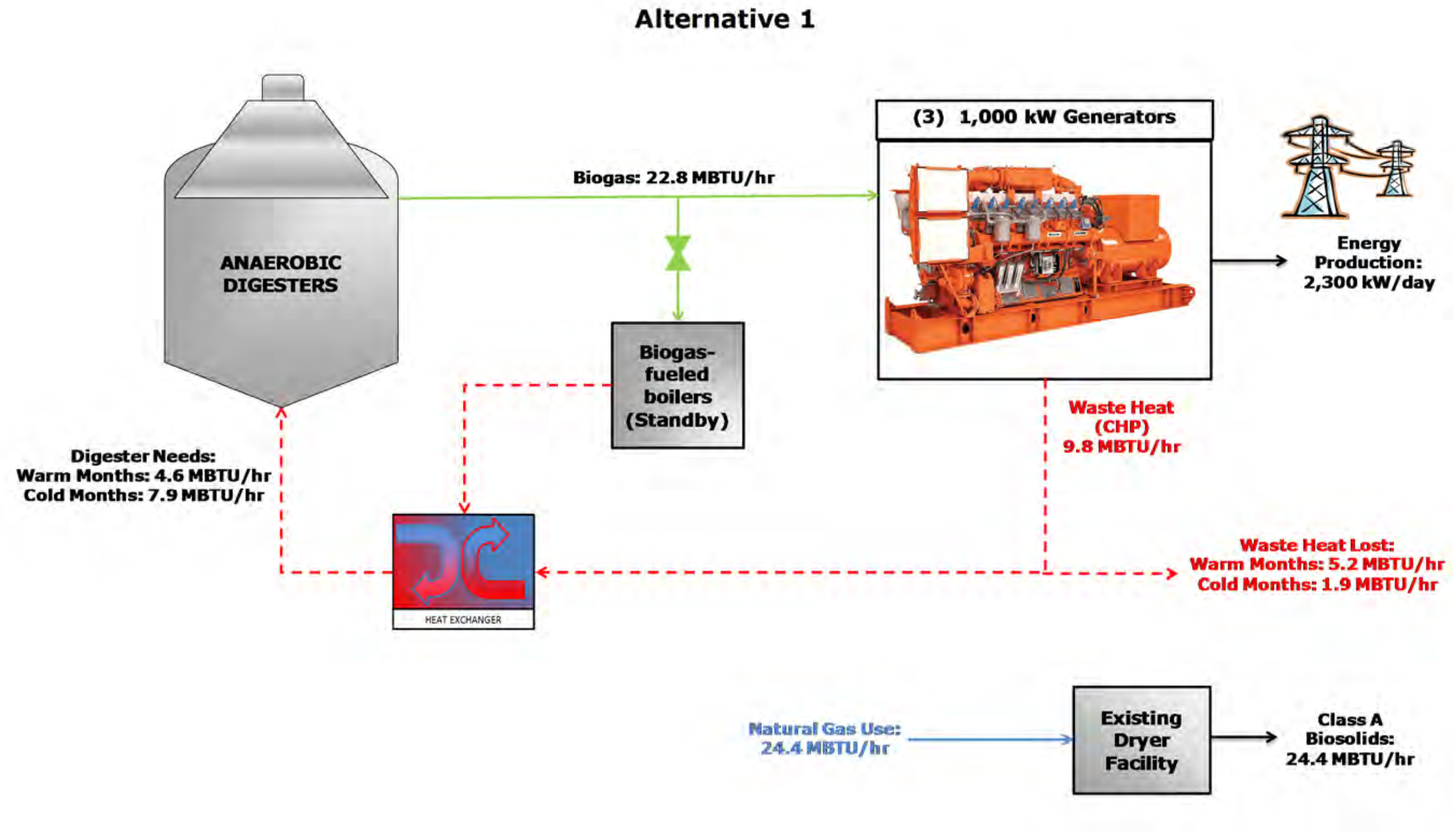


Figure 5-1: Alternative No. 1 Energy Balance Schematic

5.1.2 Alternative 2 - New CHP engines with waste heat used to heat digesters and excess waste heat utilized in absorption chillers

Alternative No. 2 consists of installing in the existing generator building three new 1,000 kW IC engines with CHP packages. The waste heat from the engines will be utilized to heat digesters. Waste heat in excess of digester needs could be used in absorption chillers to provide heating and air conditioning to plant buildings. The advantages, disadvantages, and the primary components of Alternative No. 2 are listed in **Table 5-2**. **Figure 5-2** shows an energy balance schematic for Alternative 2.

Table 5-2
Primary Components and Advantages and Disadvantages for Alternative No. 2

Alternative 2- New CHP engines with waste heat used to heat digesters and excess waste heat utilized in absorption chillers	
Primary Components	**Advantages**
• Demolition of existing engines • New CHP engine packages • Gas conditioning/cleaning • Switchgear/electrical systems • Instrumentation/control • Chiller units	• Increased power production • Utilize all biogas for energy production • Eliminates biogas use in boilers • All waste heat is utilized • Reduced maintenance cost
	Disadvantages
	• Complexity and possible unreliability as a source of heat and air conditioning • Does not offset natural gas use in dryer • Requires capital investment

Alternative 2

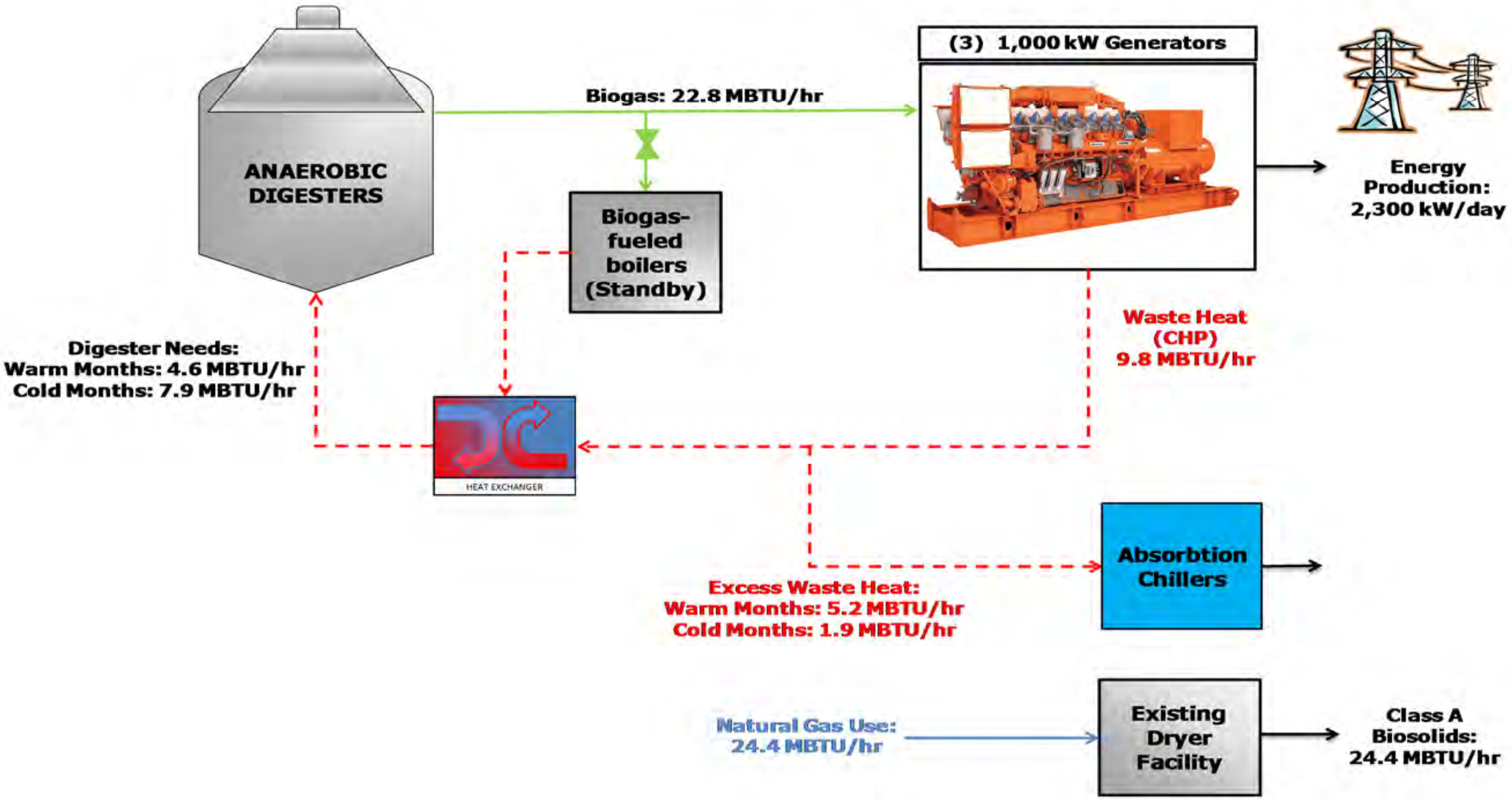


Figure 5-2: Alternative No. 2 Energy Balance Schematic

5.1.3 Alternative No. 3 - New engines installed in TECO engine building

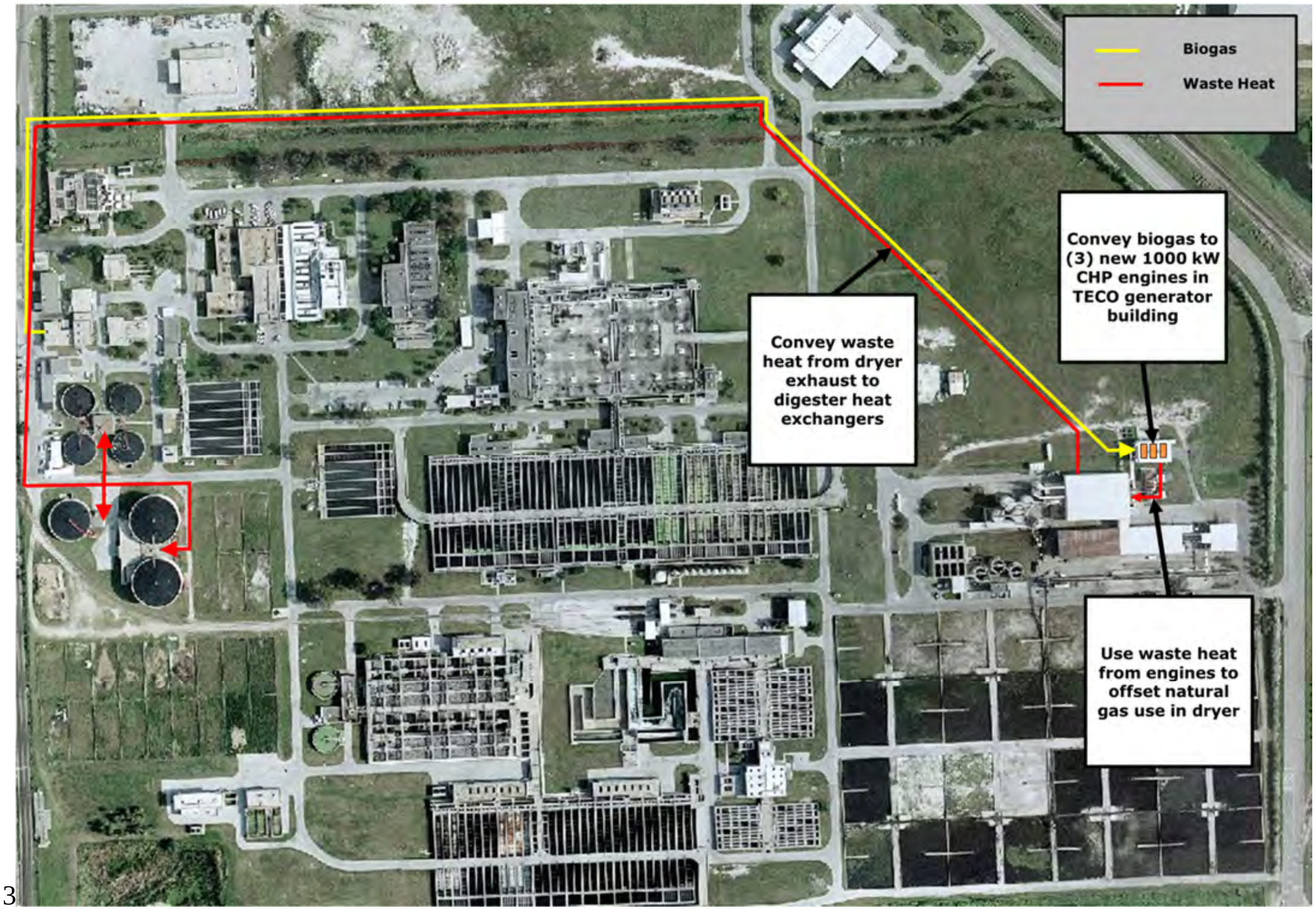
The TECO engine building currently houses two 2.9 MW Waukesha engines. The engines were installed in 2000 to provide backup power to the HFCAWTP. The engines' exhaust heat is piped and routed to each sludge dryer burner to supplement and in some instances, provide full heating loading needed to run dryer operations. The engines were abandoned in place due to operational difficulties.

Alternative No. 3 consists of replacing the existing TECO engines with three new 1,000 kW engines. The waste heat from the engine exhaust will be utilized to supplement heat demands by the dryer operations and natural gas usage. The engine jacket water will be conveyed through an underground pipeline to tie-in with existing hot water piping to the anaerobic digesters' heat exchangers. The project includes installing jacket water pumps to convey the jacket water to the heat exchangers and biogas blowers to convey the biogas from the anaerobic digesters to the TECO engine building.

Figure 5-3 shows a diagram illustrating the conceptual level site and equipment layout. **Figure 5-4** shows an energy balance schematic for Alternative No. 3. The advantages, disadvantages, and the primary components of Alternative No. 3 are listed in **Table 5-3**.

Table 5-3
Primary Components and Advantages and Disadvantages for Alternative No. 3

<table>
<tr><th colspan="2">Alternative No. 3- New engines installed in TECO engine building</th></tr>
<tr><th>Primary Components</th><th>Advantages</th></tr>
<tr><td rowspan="3">• Demolition of existing engines
• New CHP engine packages
• Biogas pipeline
• Large compressors to convey biogas
• Switchgear/electrical systems
• Instrumentation/control
• Gas conditioning/cleaning
• Waste heat pipeline from dryers to digester heat exchangers
• Demolition of TECO engines and refurbishment of TECO building</td><td>• Increased power production
• Utilize all biogas for energy production
• Engine waste heat used to offset natural gas use in the dryer</td></tr>
<tr><th>Disadvantages</th></tr>
<tr><td>• Long distance for energy transfer (higher heat losses)
• Requires refurbishment of TECO building
• Requires higher capital investment
• Existing dryer repair necessary to receive full benefits</td></tr>
</table>



Convey biogas to (3) new 1000 kW CHP engines in TECO generator building

Convey waste heat from dryer exhaust to digester heat exchangers

Use waste heat from engines to offset natural gas use in dryer

3

Figure 5-3: Alternative No. 3 Conceptual Level Site and Equipment Layout

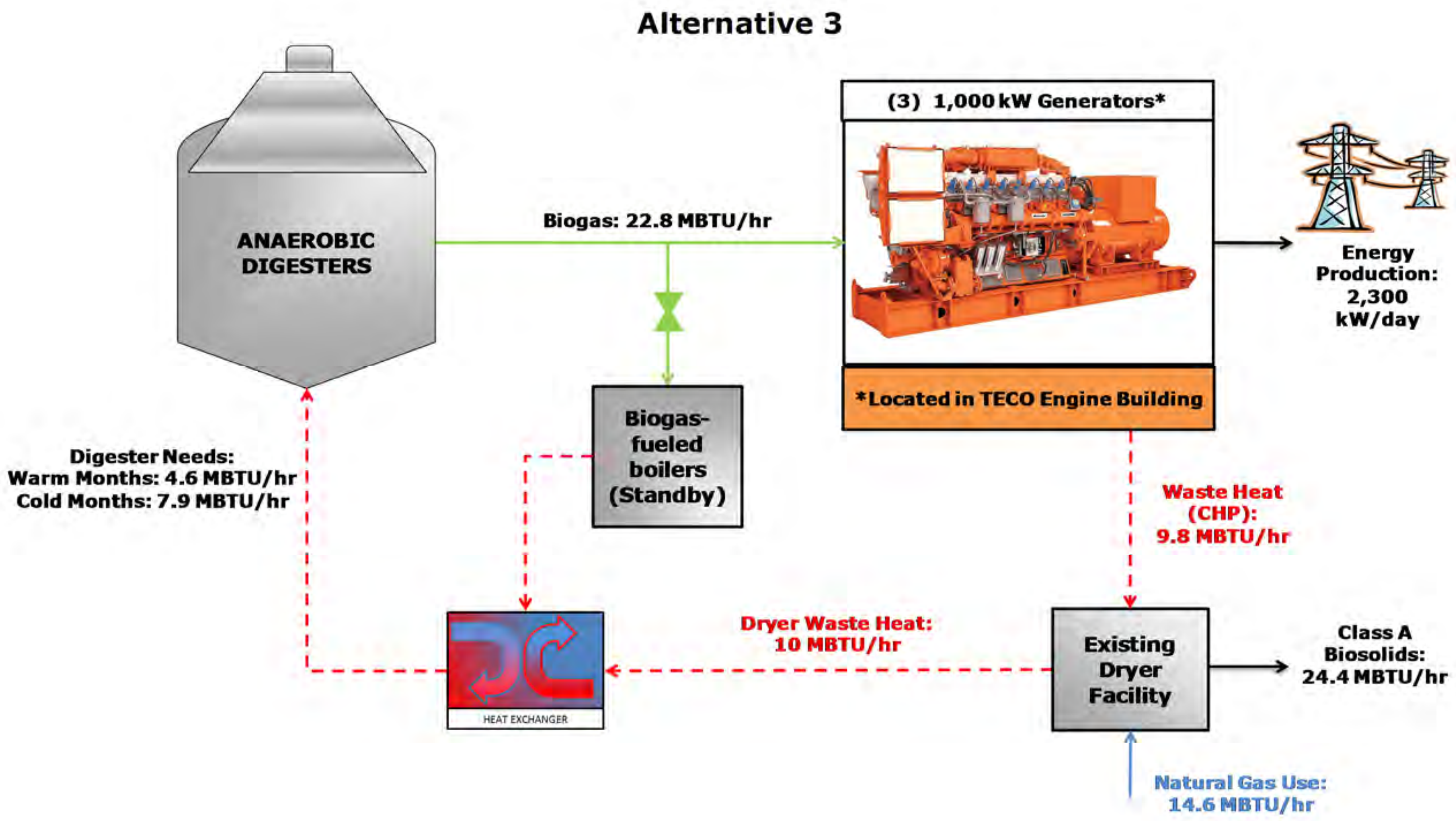


Figure 5-4: Alternative No. 3 Energy Balance Schematic

5.1.4 Alternative No. 4 - New engines installed at existing engine building with waste heat to new dryer facilities

The City of Tampa is evaluating investing $9.5 million in repairs to the existing sludge dryer trains and $5.5 million in a new sludge dewatering facility. The Biosolids Processing Assessment Report indicated that the sludge dryer repairs will provide the sludge dryer facility with less than 10 years of useful life. Instead of investing in repairs to the sludge dryer facility, Alternative No. 4 considers building a new sludge dryer facility, along with dewatering facilities, near the digester structures. Three new 1,000 kWh engines will be installed in the existing engine building so the waste heat can be used to supplement the heat demands in a new dryer facility.

Figure 5-5 shows the conceptual site plan for Alternative No. 4. **Figure 5-6** shows an energy balance schematic for Alternative No. 4. The advantages, disadvantages, and the primary components of Alternative No. 4 are listed in **Table 5-4**.

Table 5-4
Primary Components and Advantages and Disadvantages for Alternative No. 4

Alternative No. 4- New engines installed engine building and new dryer building	
Primary Components	**Advantages**
• Demolition of existing engines • New CHP engine packages • Gas conditioning/cleaning • New dryer facility • Exhaust pipeline from engines to new dryer • Waste Heat pipeline from dryer to digester heat exchangers	• Increased power production • Utilize all biogas for energy production • Localized system to enhance energy transfer (reduced heat losses) • Engine waste heat used to offset natural gas use • Production of Class A biosolids
	Disadvantages
	• Requires high capital investment • Higher O&M costs due to operation of engines and dryer facility

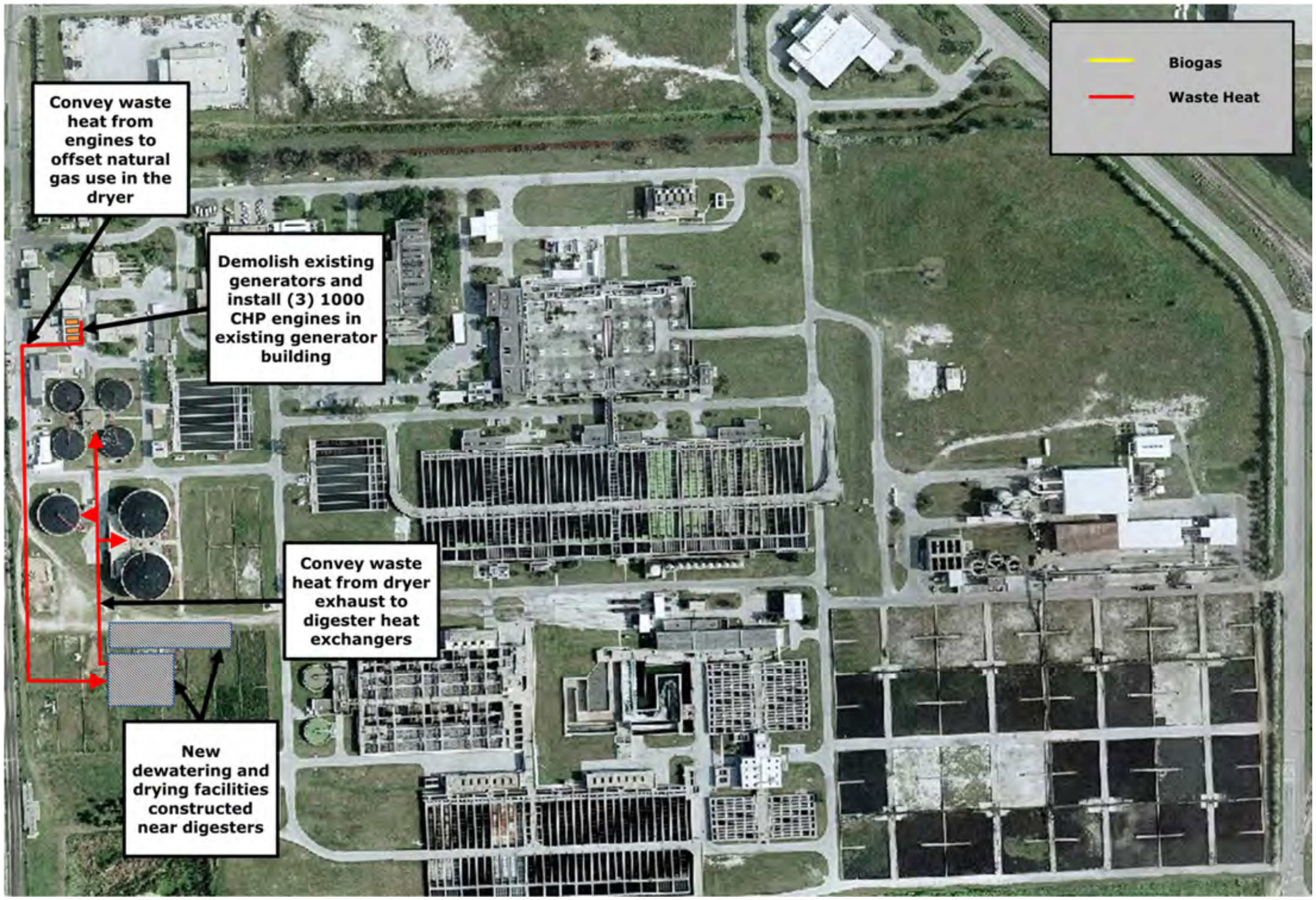


Figure 5-5: Alternative No. 4 Conceptual Level Site Plan

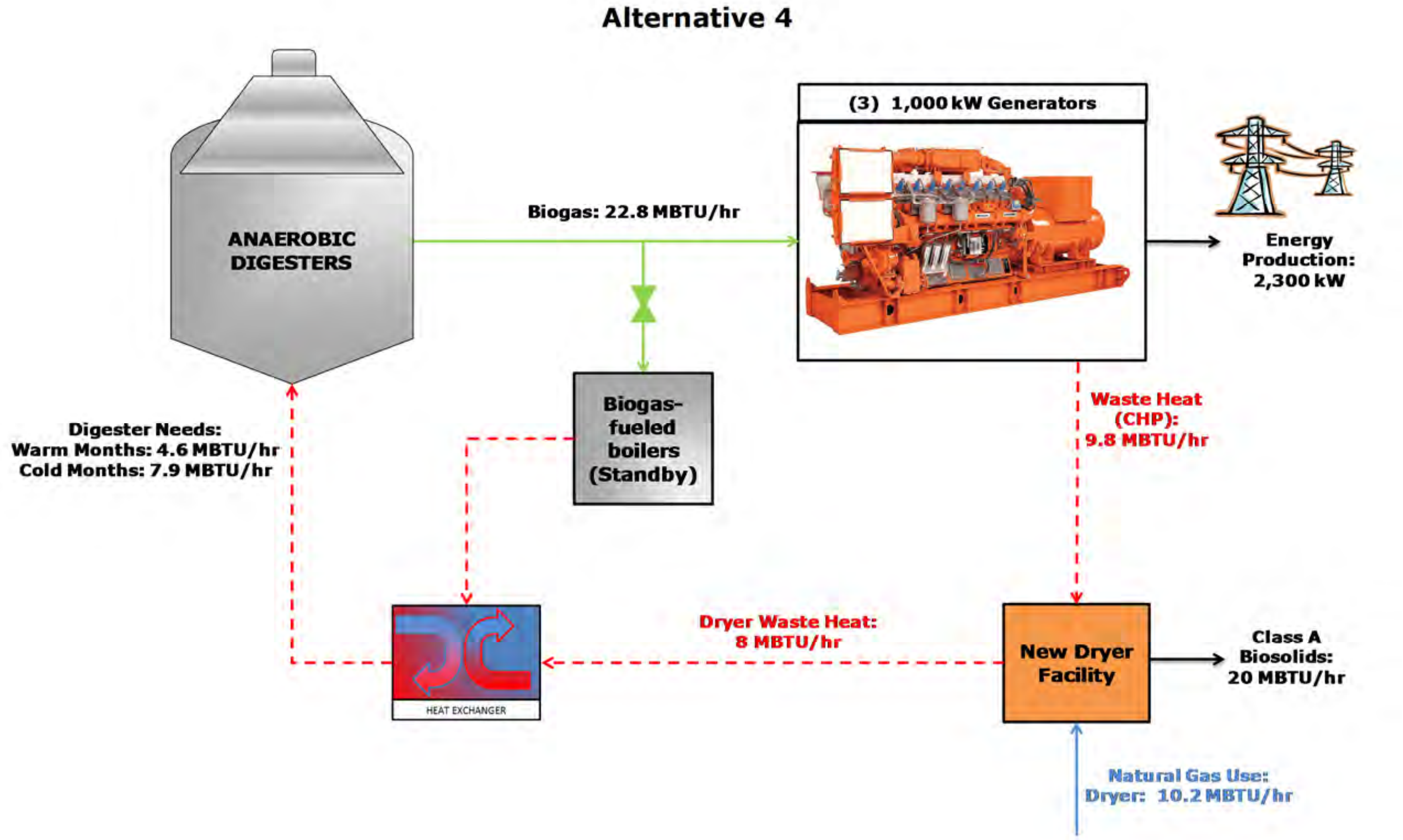


Figure 5-6: Alternative No. 4 Energy Balance Schematic

5.1.5 Alternative No. 5 - All biogas to fuel the dryer facility

Alternative No. 5 is to use all the biogas to fuel the existing dryer facility. A report prepared by another consultant (Hazen and Sawyer 2012) identified that the dryer operation uses 18.6 MBTU/dry ton. The report also indicated that the future sludge production is estimated to be 31 dry tons/day. This translates into a dryer facility usage of approximately 25 MBTU/hr. The HFCAWTP produces enough biogas to offset almost all of the natural gas usage in the dryer operations.

The net dryer waste heat available is 11 MBTU/hr. This amount is sufficient to supply the seasonal heat required by the anaerobic digesters. A pipeline will need to be constructed to convey the waste heat from the dryer facility to the anaerobic digester facilities. Another pipeline and biogas booster blowers will need to be constructed to convey the biogas from the anaerobic digesters to the dryer facility. The existing IC engines will be decommissioned and no power production equipment is included under this alternative.

The main advantages, disadvantages, and the primary components of Alternative No. 5 are listed in **Table 5-5**. **Figure 5-7** presents a conceptual site plan for Alternative No. 5 and **Figure 5-8** shows an energy balance schematic.

Table 5-5
Primary Components and Advantages and Disadvantages for Alternative No. 5

Alternative 5	
Primary Components	**Advantages**
• Demolition of existing engines • Biogas pipeline to existing dryer facility • Large compressors to convey biogas across plant • Waste heat pipe line from dryers to digester heat exchangers • Instrumentation/control • Refurbishment of existing dryer facility	• No capital investment for CHP engines • No O&M costs for CHP engines • No biogas conditioning required • Utilize all biogas to offset natural gas use in dryers
	Disadvantages
	• Long distance for energy transfer (higher losses) • No power production • Not utilizing all waste heat • Existing dryer facility must be repaired

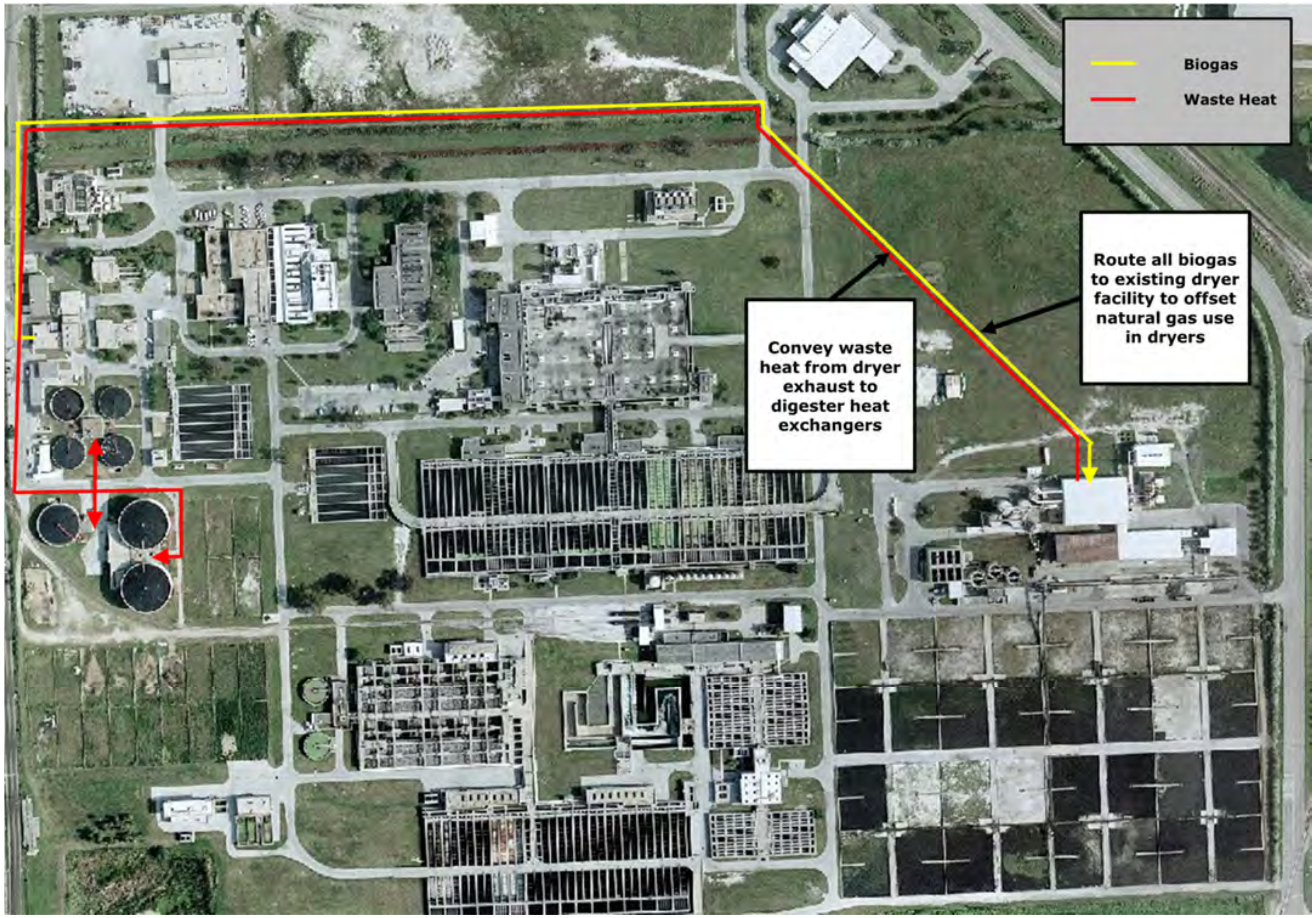


Figure 5-7: Alternative No. 5 Conceptual Level Site Plan

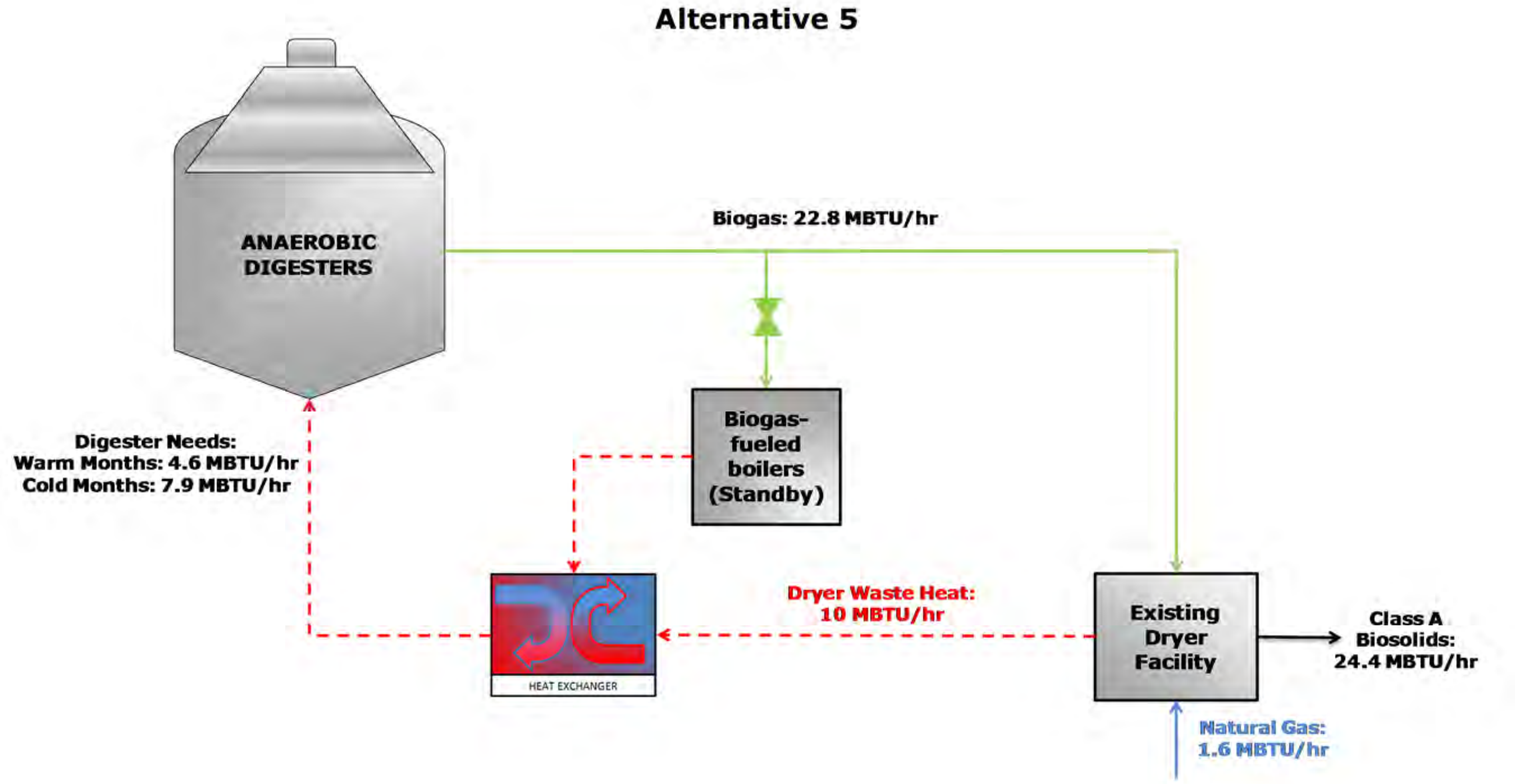


Figure 5-8: Alternative No. 5 Energy Balance Schematic

5.1.6 Alternative No. 6 - All biogas to new dryer facility

Alternative No. 6 is similar to Alternative No. 5, where all the biogas is used to offset the natural gas usage in the dryer facilities. Alternative No. 6 considers building a new sludge dryer facility, along with dewatering facilities, near the digester structures. The net waste heat from the dryers will be used for heating of the anaerobic digesters. The existing IC engines will be decommissioned and no power production equipment is included under this alternative.

The advantages, disadvantages, and the primary components of Alternative No. 6 are listed in **Table 5-6**. **Figure 5-9** presents a conceptual site plan for Alternative No. 6 and **Figure 5-10** shows an energy balance schematic.

Table 5-6
Primary Components and Advantages and Disadvantages for Alternative No. 6

Alternative 6	
Primary Components	**Advantages**
• Demolition of existing engines • New dryer facility • Use existing gas compressors • Biogas pipeline • Waste heat pipeline from dryer to digester heat exchangers	• No capital investment for CHP engines • No O&M cost for CHP engines • No biogas conditioning required • Utilizes all biogas to offset natural gas use in new dryer • Localized system to enhance energy transfer (lower losses)
	Disadvantages
	• High capital costs for new dryer facility • No power production • Not utilizing all waste heat

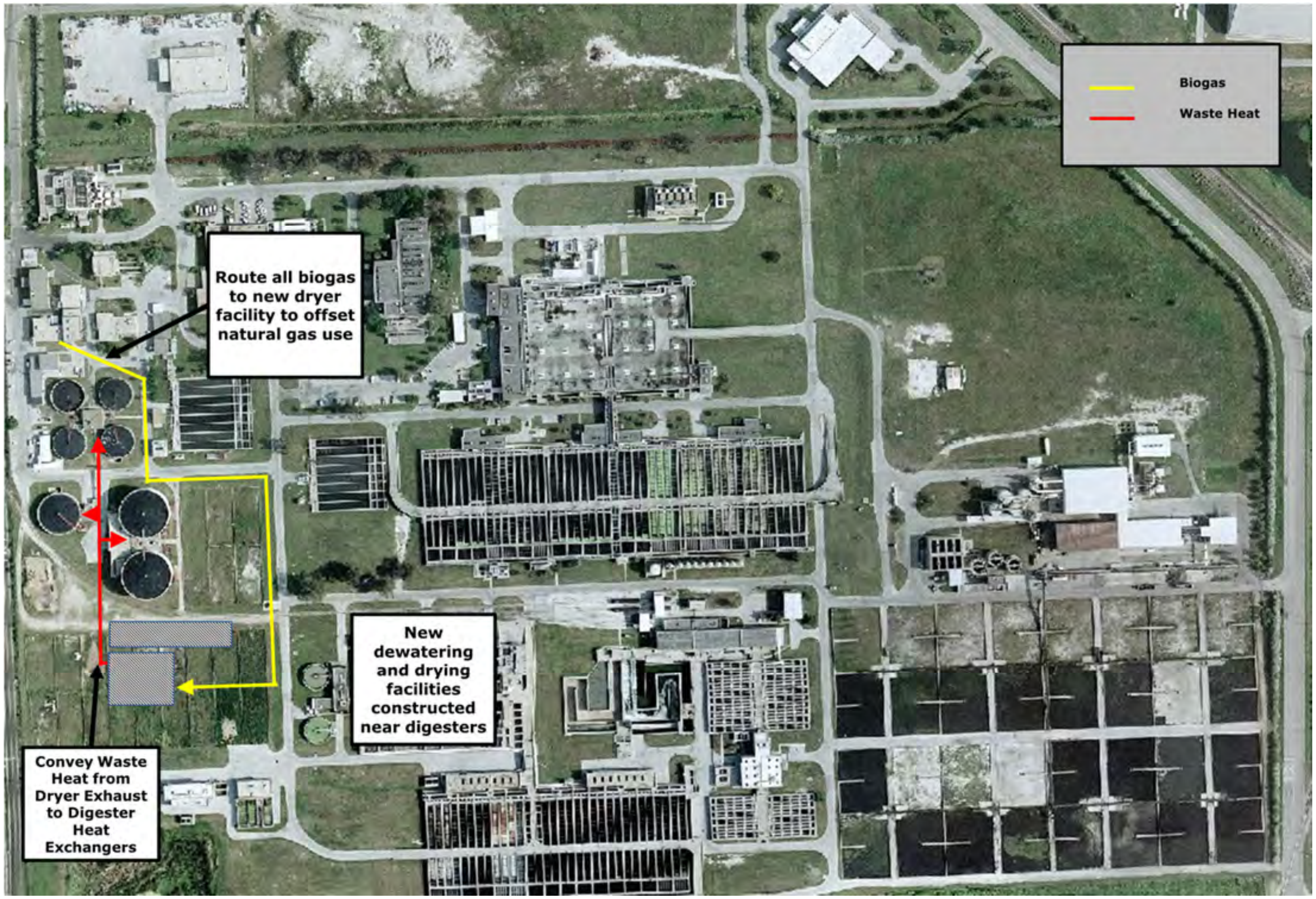


Figure 5-9: Alternative No. 6 Conceptual Level Site Plan

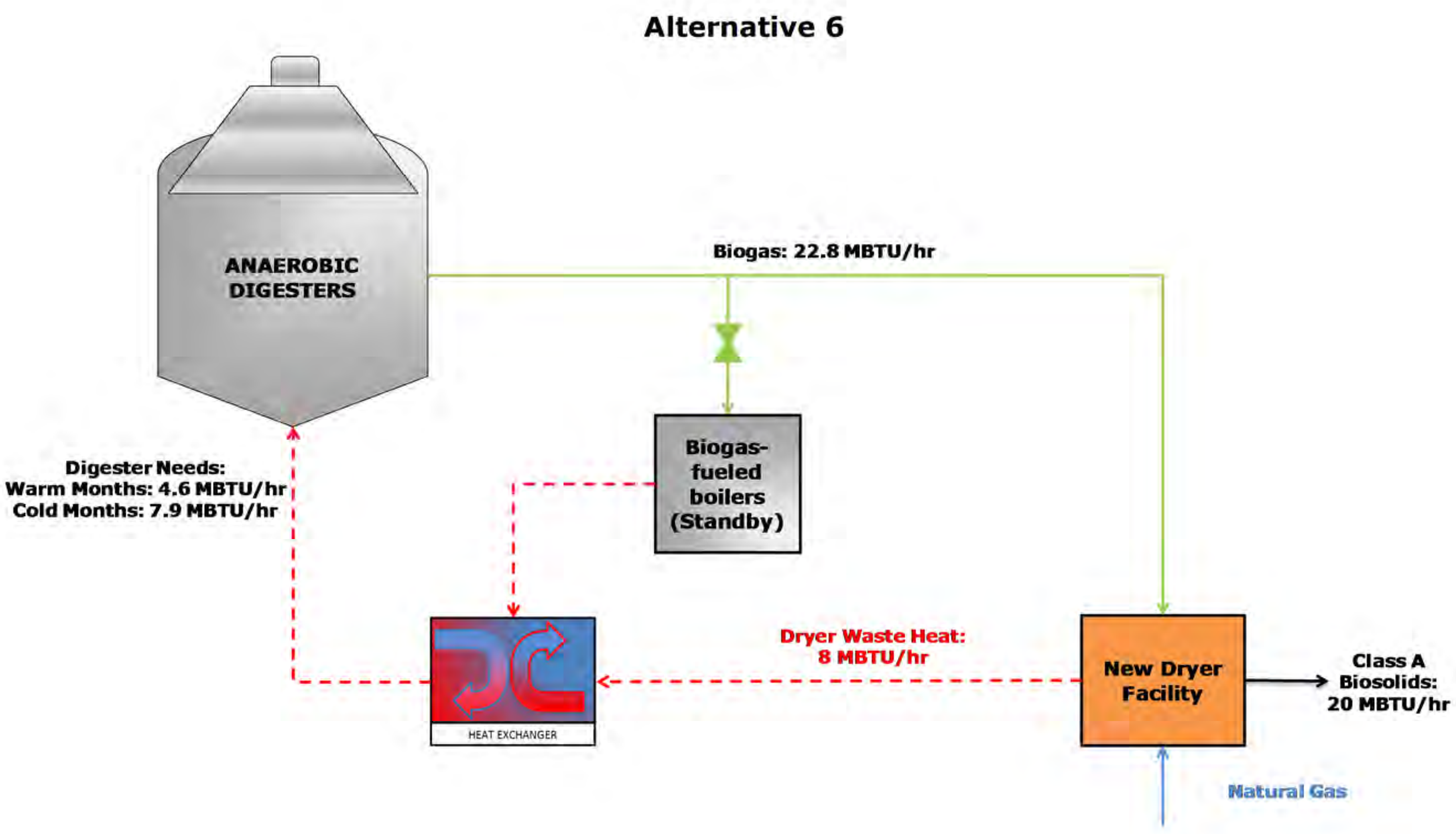


Figure 5-10: Alternative No. 6 Energy Balance Schematic

5.2 Initial Biogas Utilization Alternatives Screening

The six alternatives presented above were screened during a workshop with the City of Tampa on July 17, 2012. The screening criteria were chosen based on the attributes the City found most relevant to the biogas utilization and of more importance for the HFCAWTP operations and costs. For each criterion, a score from 1 to 4 was assigned to each of the alternatives with 1 being the least favorable and 4 being the most favorable.

5.2.1 Screening Criteria

The screening criteria are as follows:

Capital Cost - The total present worth of each alternative's capital cost is very important to the City. During the screening process, capital cost was estimated based on the primary components of each alternative. Alternatives with the highest capital cost were given a score of 1 out of 4 and the lowest capital costs were given a score of 4 out of 4.

Operational savings - Each of the alternatives should provide operational savings to the City by producing power, offsetting natural gas purchase, or both. The alternatives that provided the most operational savings were given a score of 4 out of 4 and those that provided none were given a score of 1 out of 4.

Waste heat utilization - It is important to the City that that the preferred alternatives are as highly efficient as possible and utilize waste heat. Alternatives that utilized the most waste heat were given a score of 4 out of 4 and alternatives that utilized none of the waste heat were given a score of 1 out of 4.

System complexity - For this criterion, the level of complexity of the equipment is considered as well as repair and maintenance issues. Those alternatives that exhibited the highest degree of complexity were given a score of 1 out of 4 and the alternatives that were the least complex were given a score of 4 out of 4.

Ability to phase - The City expressed concern that the preferred alternatives must be able to phased in with other facility projects. The most significant projects were those to repair and upgrade the existing water jacket system and the repair and upgrade of the dewatering /drying facilities. Those alternatives that could be phased with these other projects with the most ease were given a score of 4 out of 4 and those that raised the most concern of phasing were given a score of 1 out of 4.

5.2.2 Screening Results

Capital Cost- **Table 5-7** outlines the scores given to each of the alternatives for capital cost. Alternative No. 5 was given a score of 4 because this Alterative has the least components, and therefore the one with the least expected capital cost. Alternative 4 was given a score of 1 as it includes installing new engines as well as constructing a new drying facility, both requiring higher capital investment.

Table 5-7
Capital Cost Scoring (4 ranking is lowest cost)

	Capital Cost Score
Alternative 1	3
Alternative 2	3
Alternative 3	3
Alternative 4	1
Alternative 5	4
Alternative 6	2

Capital costs to repair the dryer facility were not considered in the capital cost ranking, costs to repair the dryer facility are considered common to all alternatives.

Operational savings – **Table 5-8** outlines the scores given to each of the alternatives for operational savings. Alternatives 3 and 4 both received scores of 4 for this criterion as they provide operational savings through natural gas offsets and power production. Alternatives 1 and 2 only offer power production for offset and received a score of 2. Alternatives 5 and 6 offset natural gas purchase and received scores of 3 as the natural gas offset is more valuable than power offset. The natural gas cost is slightly higher than the cost of power billed to the City.

Table 5-8
Operational Savings Scoring

	Operational Savings Score
Alternative 1	2
Alternative 2	2
Alternative 3	4
Alternative 4	4
Alternative 5	3
Alternative 6	3

Waste heat utilization- **Table 5-9** summarizes the scores given to each of the alternatives for waste heat utilization. Alternative 2 received the only 4 as it is the only alternative that captures and utilizes all the available waste heat. Alternative 1 does not utilize all the waste heat available and therefore received a score of 2. The other alternatives received a score of 3 for the minimal waste heat utilization they provided.

Table 5-9
Waste Heat Utilization Score

	Waste Heat Utilization Score
Alternative 1	2
Alternative 2	4
Alternative 3	3
Alternative 4	3
Alternative 5	3
Alternative 6	3

System Complexity- **Table 5-10** summarizes the scores given to each of the alternatives for system complexity. Alternative No. 2 received a score of 1 due to the complexity surrounding the absorption chiller system. In addition, the City recently invested in new air conditioning units for the entire HFCAWTP, thus any new modifications to the HVAC system are not in the current City budget. Alternatives 3 and 4 received scores of 2 as they contain both co-generation and dryer components which is more complex in operation than Alternatives 5 and 6. Alternatives 5 and 6 received scores of 3 as they only contain either co-generation or dryer components. It should be noted that alternative 1 is very similar to the current operation at HFCAWTP and received a score of 4.

Table 5-10
System Complexity Scores

	System Complexity Score
Alternative 1	4
Alternative 2	2
Alternative 3	2
Alternative 4	2
Alternative 5	3
Alternative 6	3

Ability to phase- **Table 5-11** summarizes the scores given to each of the alternatives for their ability to be phased. Alternative 1 was given a score of 4 because it will easily phase with the jacket water project and has no dependency on the dewatering/drying project. Alternatives 5 and 6 received a score of 1 as they are completely dependent on the dryer facility repair or the construction of a new dryer facility to provide any benefit. Alternatives 3 and 4 received scores of 3 as they will provide some benefit without dryer repair or dryer construction but won't provide their full benefit without it. Alternative 2 received a score of 2 because it will be difficult to phase the chiller product into the recently upgraded HVAC system.

Table 5-11
Ability to Phase Scores

	Ability to Phase Score
Alternative 1	4
Alternative 2	2
Alternative 3	3
Alternative 4	3
Alternative 5	1
Alternative 6	1

Table 5-12 summarizes the scores for each of the alternatives in the screening criteria categories.

Table 5-12
Scoring Summary

	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6
Capital Cost	3	3	3	1	4	2
Operational Savings	2	2	4	4	3	3
Waste Heat Utilization	2	4	3	3	3	3
System Complexity	4	2	2	2	3	3
Ability to Phase	4	2	3	3	1	1
Total	**15**	**13**	**15**	**13**	**14**	**12**

These results show that Alternative Nos. 1, 3 and 5, with the highest overall numerical score, are the most favorable for the City. It is important to note that there are significant capital costs required to repair the existing dryer facility as required in Alternatives 3 and 5, and these costs are not included in the capital cost ranking. A detailed economic evaluation will be conducted on each of the preferred alternatives to determine what would be the best business case alternative for biogas utilization at the HFCAWTP.

5.2.3 Additional Biogas Use Alternatives

During the preliminary screening of the six alternatives, the City requested that two additional alternatives be evaluated for comparision purposes. These include:

5.2.3.1 Alternative 5a - Use biogas to fuel boilers and route excess to existing dryer facility

Alternative 5a is similar to Alternative 5 except that the primary use of the biogas becomes the heating of the digesters, and the secondary use is supplementing natural gas purchase in the dryer. This also eliminates the waste heat return line running from the dryer to the digester heat exchangers. **Table 5-13** outlines the primary components, advantages, and disadvantages of alternative 5a. **Figure 5-11** shows a conceptual site plan, and **Figure 5-12** shows an energy balance for alternative 5a.

Table 5-13
Primary Components and Advantages and Disadvantages for Alternative No. 5a

Alternative 5a	
Primary Components	**Advantages**
• Demolition of existing engines • Biogas pipeline • Large compressors to convey biogas • Instrumentation/control • Existing dryer facility must be repaired	• No capital investment required for CHP engines • No O&M costs for engines • No Biogas conditioning required • Utilize all biogas to offset natural gas use in dryers
	Disadvantages
	• No power production • Capital investment required to repair existing dryer facility

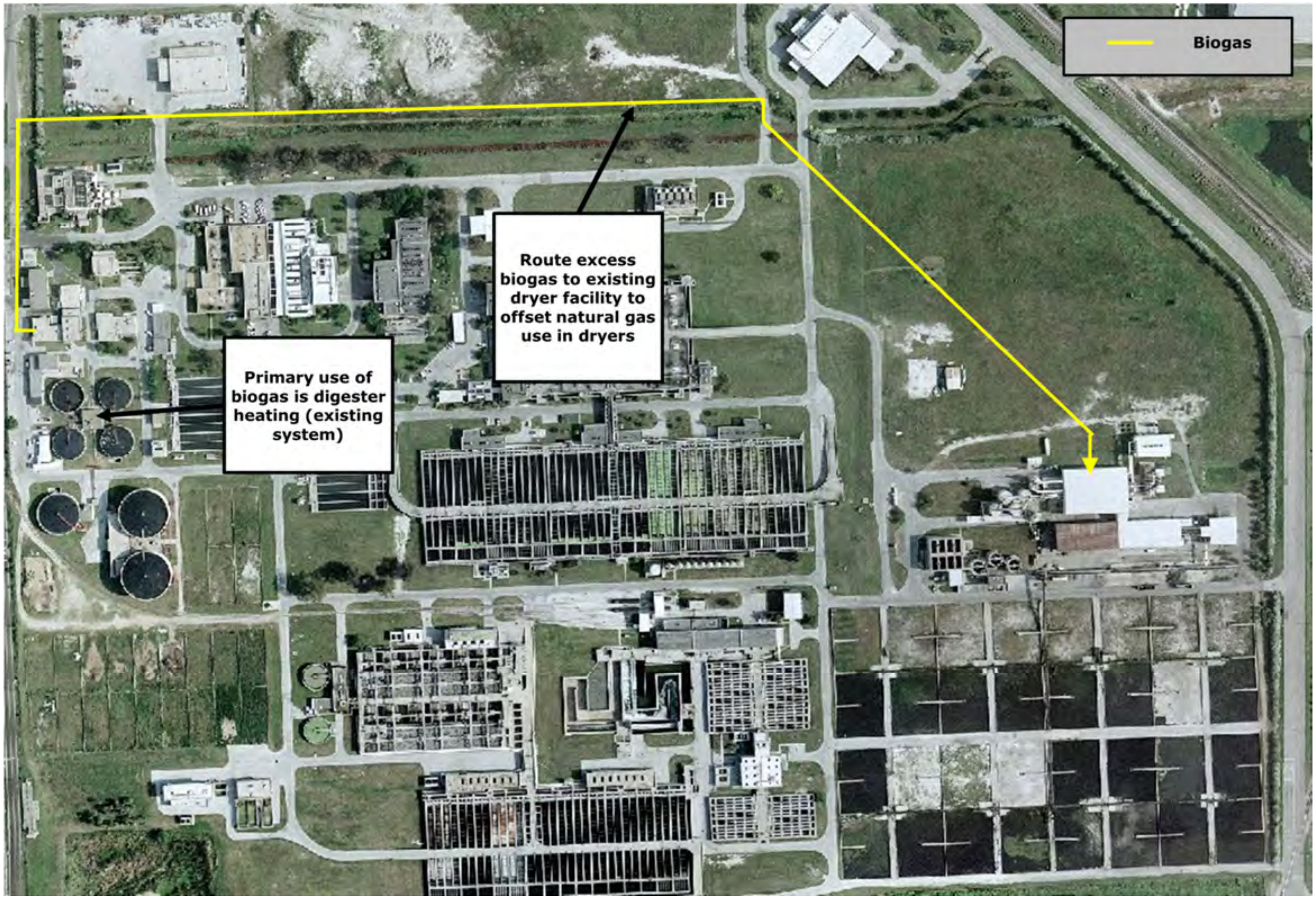


Figure 5-11: Conceptual Site Plan for Alternative 5a

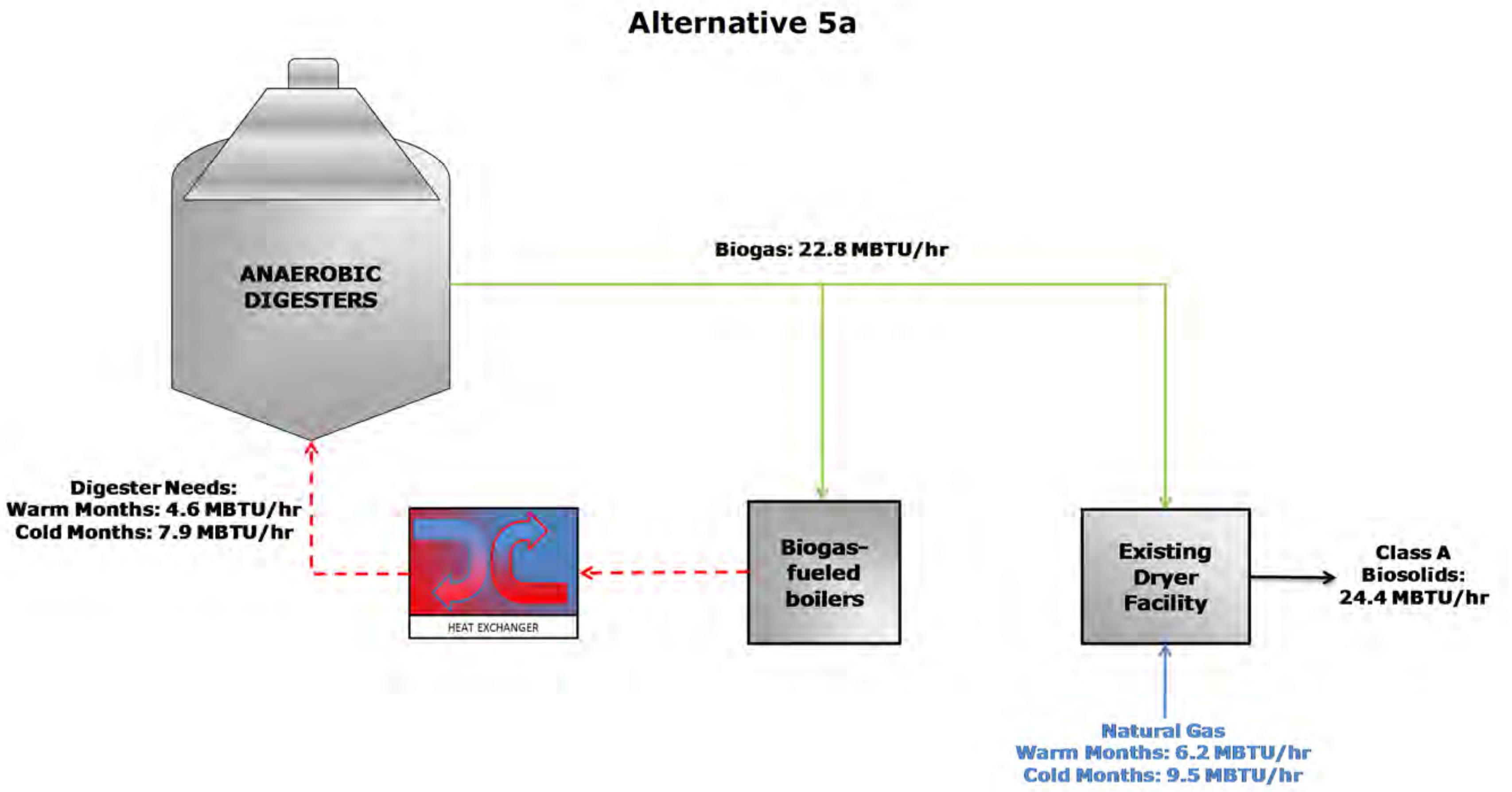


Figure 5-12: Energy Balance for Alternative 5a

5.2.3.2 Alternative 7- Use biogas to fuel boilers and flare

Alternative 7 allows for the boilers to be fueled by biogas, with the excess being flared. The City requested that this alternative be evaluated to verify that there was value in utilizing the excess biogas. This alternative requires no capital investment as all required equipment in already in use. **Table 5-14** outlines the primary components, advantages, and disadvantages of alternative 5a. **Figure 5-13** shows a conceptual site plan and **Figure 5-14** shows an energy balance for alternative 7.

Table 5-14
Primary Components and Advantages and Disadvantages for Alternative No. 7

Alternative 7	
Primary Components	**Advantages**
• Demolition of existing engines • Instrumentation/control	• No capital cost required for new CHP engines • Very low O&M cost • No biogas conditioning required
	Disadvantages
	• No power production • No natural gas offset in the dryer

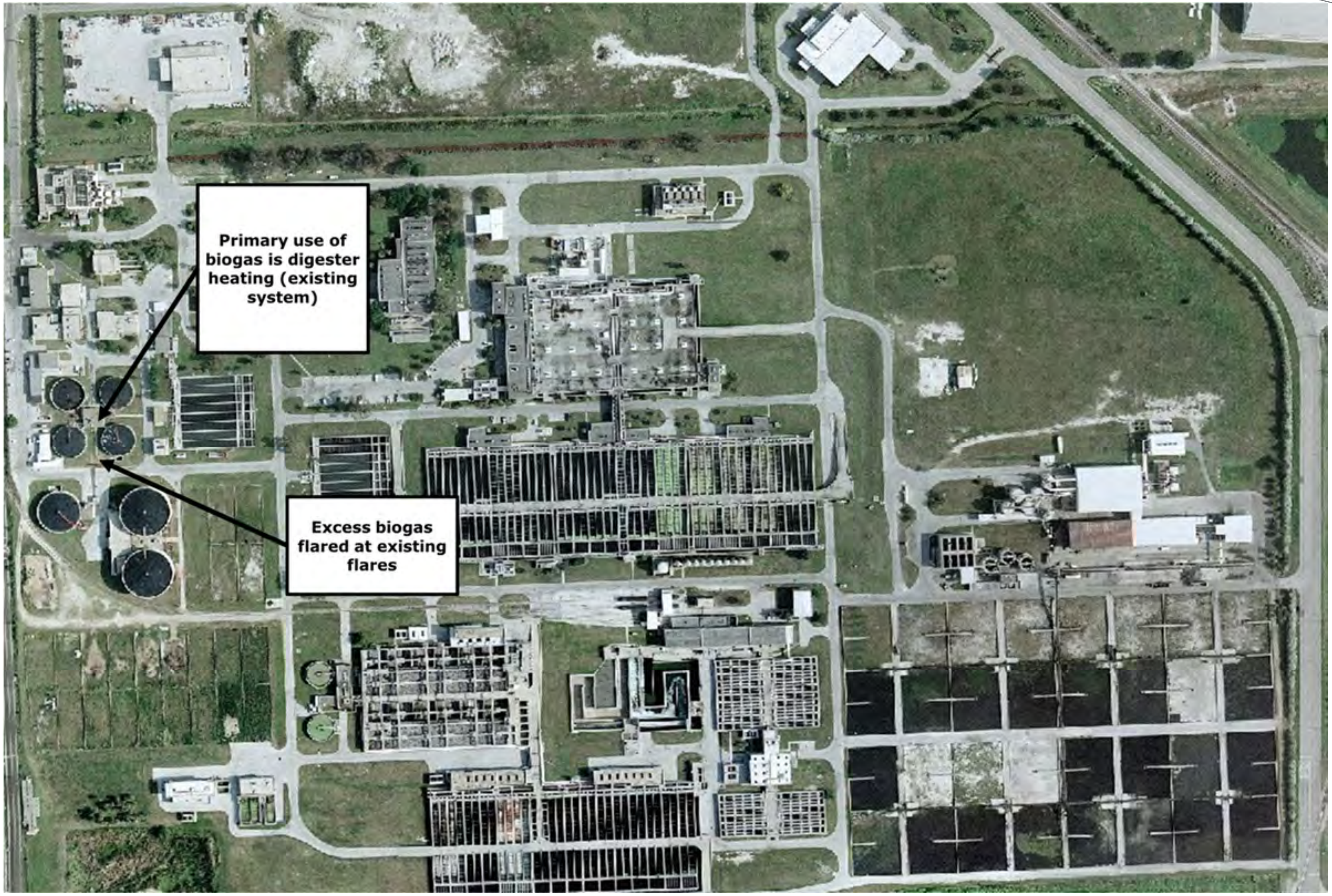


Figure 5-13: Conceptual Site Plan for Alternative 7

Alternative 7

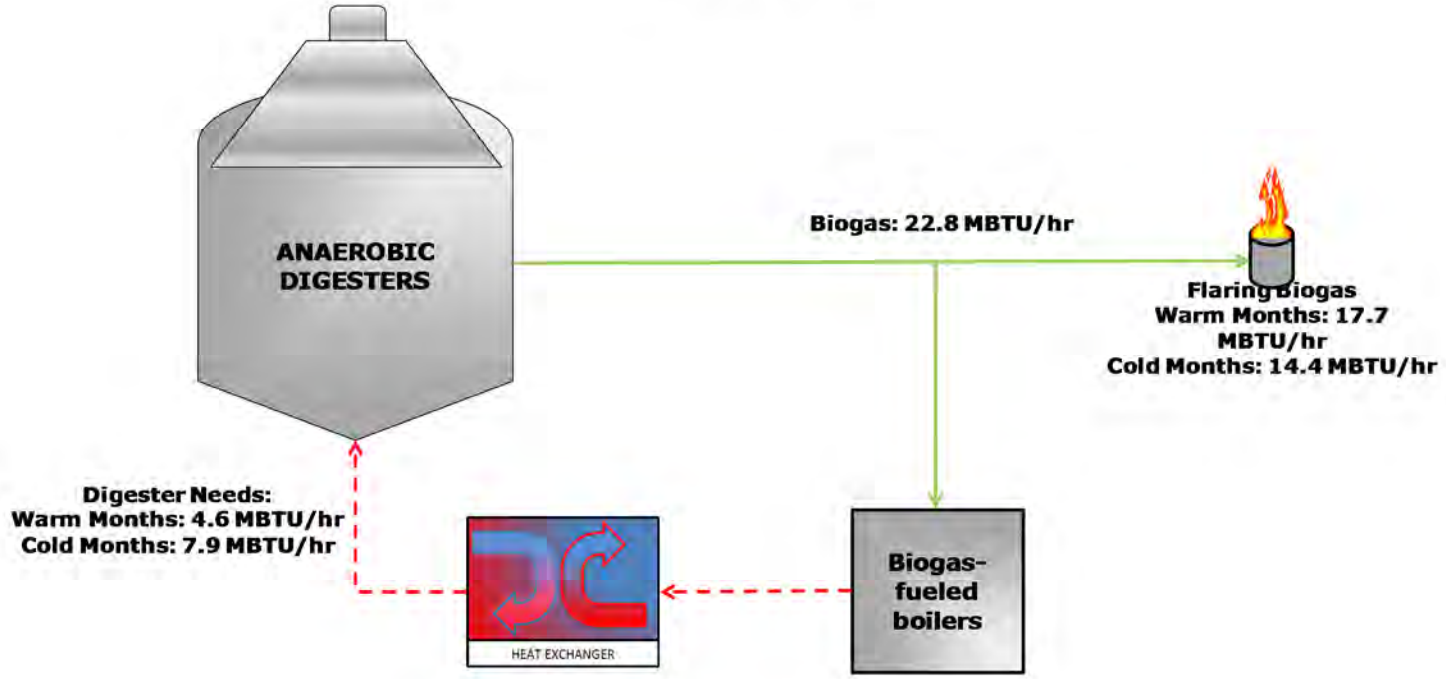


Figure 5-14: Energy Balance for Alternative 7

5.3 Other biogas utilization options

A number of other biogas processing and utilization options are available in the marketplace, several of the most often used are presented in this section. Although available, these options were not considered feasible or evaluated for the HFCAWTP. Some of these alternatives are outlined below:

- Fueling the existing TECO engines- The existing engines housed in the TECO building are very large (2.9 MW each). There is not enough biogas produced at the HFCAWTP to run these engines on biogas alone, and it is unclear whether or not they could run on a combination of biogas and natural gas. Also, these engines are old and will not alleviate the City of any maintenance costs.

- Fueling fleet vehicles - Some municipalities (i.e. Colorado Springs, CO) have constructed gas stations for their municipal fleet using biogas as fuel. Although this alternative is an environmental conscious alternative, the capital expenses, the complex logistics and difficulty in operations, represents a challenge to the City of Tampa. In addition, the biogas needs to be treated and cleaned to very stringent fuel characteristics. Biogas is high in carbon dioxide and hydrogen sulfide, which must be removed before the gas is burned in vehicle engines.

- Cleaning of biogas to natural gas- This alternative is very similar to using biogas for fleet vehicles. Treatment of the biogas to natural gas characteristics requires expensive cleaning equipment, and is power intensive. The City of Tampa’s HFCAWTP is in the business of providing high level treatment to the City’s wastewater and not in the business of treating, handling and selling natural gas quality biogas.

- Exporting biogas to other Tampa Port users- Although the HFCAWTP is located in the Port of Tampa, with easy access to trains and freight carriers, no other Port user has been identified with the need for biogas. Researching other biogas users within the area was out of the scope of this study. However, it is important to note that the HFCAWTP has a need for use of the biogas generated, as illustrated on this section. It makes more sense to the City to utilize the biogas in their facility prior to considering selling it to other outside users.

- Microturbines - Microturbine manufacturers were consulted to determine the feasibility of using their equipment at the City of Tampa’s HFCAWTP. The largest microturbine engine available in the market is 250 kW. Based on current evaluation assumptions, microturbines will not be cost effective to install because of the large amount of units needed. In addition, microturbines require more stringent fuel characteristics. The cost for cleaning the biogas to microturbine fuel characteristics is more expensive than cleaning to engine characteristics.

- Fuel cells - The fuel cell technology, although very promising, has not been fully developed. At this moment, is uncertain if this new technology is adequate for the City of Tampa. In addition, implementing this new technology will mean training, or possibly adding new skilled operators dedicated for this type of system.

6.0 Preferred Alternatives Economic Analysis

6.1 Preferred Alternatives

Based on the ranking criteria presented and discussed in Section 5, five preferred alternatives and the current system were selected for further evaluation including an economic comparison. The five alternatives that were selected for further evaluation are:

- Alternative No. 1 – New CHP engines with waste heat used to heat digesters.
- Alternative No. 3 – New CHP engines installed in TECO engine building, with exhaust waste heat to dryer to offset natural gas; and waste heat from dryer to heat digesters.
- Alternative No. 5 – All biogas to existing dryer facility and dryer waste heat recovery for digester heating.
- Alternative No. 5a – Biogas is used for heating the digesters and the remainder is fed to the existing dryer facility to offset some of the natural gas usage.
- Alternative No. 7 –Biogas is used for heating the digesters and the remainder is flared

6.2 Economic Analysis

To further evaluate the five preferred alternatives, an economic analysis that included capital and operational and maintenance costs was conducted. This analysis allows for the five alternatives to be compared in order to determine the most economically beneficial alternative. Parameters for conducting the economic analysis of the five preferred alternatives are outlined in **Table 6-1**.

Table 6-1
Parameters of Economic Analysis

Item		Notes
Capital Amortization Period	20 years	Specified by the City
Interest Rate	5%	Specified by the City
Inflation Rate	2.5%	
Natural Gas Cost	$4.50/ MMBTU	Based on current natural gas prices
Electricity Costs	$0.09/kWh	Average calculated from utility bills provided by the City

The following information, as presented in Section 3 of this report, was used in this economic analysis as well:

- Sludge production: 396,000 GPD
- Total solids concentration: 4.49%
- Volatile solids/total solids ratio: 84.3%
- Volatile solids reduction rate: 53%
- Biogas production rate: 15 ft^3/lb VSS destroyed
- Biogas heating value: 550 BTU/ft^3
- Biogas production: 22.8 MMBTU/hr
- Digester heating requirements: 46,872 MMBTU/YR

The above values are based on historical plant data and biogas testing, with the exception of the biogas production rate of 15 ft^3/lb VSS destroyed which was used based on literature values as discussed in section 3.1. All of the above information was assumed to remain steady through the 20 year design life.

Determining the costs associated with certain portions of the biosolids handling process was outside the scope of this study and not included in the capital cost of each alternative. Assumptions were made to allow for a complete economic analysis. The assumptions made in this economic analysis include:

- Dewatering improvements. This work is already in the planning stages and a budget has been allocated in the City of Tampa’s Capital Improvement Program (CIP); this requirement is common to all alternatives and the costs will not be included in this analysis.
- Dryer facility repair: Dryer facility repairs are not within the scope of this study and the costs associated with the repair are not included, though it should be noted that the repairs are necessary for Alternatives 3, 5, and 5a to produce maximum revenue from natural gas offset.
- Biosolids dewatering and disposal costs are also outside the scope of this project and are not included in this economic evaluation

6.2.1 Annualized Analysis

The economic analysis is this section will present annualized values for costs and benefits for each of the preferred alternatives in order to allow for direct cost comparisons. These annualized values allow for inflation and the time value of money to be considered. In order to calculate the annualized values, costs and revenues for each alternative were estimated for FY2012 and then increased by the specified inflation rate of 2.5% over 20 years, to coincide with the capital cost amortization period. These annual costs were then equated to a net present worth which was annualized over the same 20 year period using a 5% interest rate.

For example, **Table 6-2** shows the estimated labor costs for the current biogas system. Year one is equal to the FY2012 labor cost estimate provided by the City and in each subsequent year this value is increased by 2.5% to account for inflation.

Table 6-2
Labor Costs for the Current System

Year	Labor Cost
1	$480,552
2	$492,566
3	$504,880
4	$517,502
5	$530,439
6	$543,700
7	$557,293
8	$571,225
9	$585,506
10	$600,144
11	$615,147
12	$630,526
13	$646,289
14	$662,446
15	$679,007
16	$695,983
17	$713,382
18	$731,217
19	$749,497
20	$768,235
Net Present Value	$7,350,959.68
Annualized Value	$589,860

At the bottom of Table 6-2, a net present value of $ 7.4 million dollars is shown; this value represents the amount of money that the City would have to pay today to cover the labor costs for the current system for the next 20 years. The annualized value presented represents the equivalent cost of labor if the labor costs were paid in equal annual payments over the 20 year period.

Annualized values for capital cost, labor cost, parts/materials cost, electricity revenue, natural gas offset revenue and net benefit are presented for each alternative. The annualized values allow the alternatives to be compared on a uniform annual basis.

6.2.2 Alternative Capital Costs

Capital costs were estimated for the alternatives and include the major components for each potential project as well as proposed infrastructure improvements. Engineering and administration costs are also included.

Table **6-3** presents the estimated total capital costs for each of the five selected alternatives, and the current system. Line item capital cost estimates for each alternative are broken down by component and included in **Appendix B**.

Table 6-3
Feasibility Level Capital Cost Estimates for Preferred Alternatives

Alternative	Capital Cost	Annualized Capital Cost
Alternative 1	$ 8,622,975	$ 691,930
Alternative 3	$ 11,820,225	$ 948,485
Alternative 5	$ 4,506,375	$361,603
Alternative 5a	$ 1,467,000	$ 117,716
Alternative 7	$ 0	$ 0
Current System	$ 0	$ 0

As **Table 6-3** shows, Alternative 7 and the current system require no capital investment as repair and maintenance costs are included in O&M costs. Both of these alternatives operate using equipment already in place at HFCAWTP.

6.2.3 Operational and Maintenance Costs

Operation and maintenance (O&M) costs were estimated for proposed and existing equipment and facilities required for each alternative. A complete line item breakdown of operation and maintenance costs for each alternative's first year of operation can be found in **Appendix B**, these costs will be increased annually to account for inflation. Included within the O&M costs are:

- Biogas conditioning and conveyance
- Engine operation and maintenance
- Blower/Compressor operation and maintenance
- Boiler operation and maintenance
- Permitting costs
- Revenue from power generation/natural gas offset

The O&M costs associated with the current biogas system in FY2012 were provided by the City and a complete breakdown can be found in **Appendix B**.

Table 6-4 summarizes the annualized estimates for O&M costs for each of the five preferred alternatives, and the current system, presented as labor or parts/materials costs.

Table 6-4
Annualized O&M Cost Estimates

Alternative	Annualized Labor Cost	Annualized Parts/Materials Cost
Alternative 1	$438,038	$180,955
Alternative 3	$438,038	$186,570
Alternative 5	$50,534	$44,919
Alternative 5a	$50,534	$44,919
Alternative 7	$36,824	$42,961
Current System	$589,860	$395,243

Table 6-4 shows that Alternatives 5, 5a and 7 have the lowest O&M costs, this is because those alternatives do not utilize engines. Alternatives 1, 3, and the current system have significantly higher O&M costs due to the costs associated with engines. The current system has the highest O&M cost due to the age of the existing engines and the inefficiencies of the current biogas conditioning system.

6.2.4 Generated Revenues

Revenues generated by each of the alternatives vary depending on how the biogas can be used. Alternatives 3, 5 and 5a will generate additional revenue if the dryer facility is operational.

Given that future repairs of the existing dryer facilities are uncertain, the City requested that each of the alternatives be evaluated for two separate scenarios:

- Scenario 1: The existing dryer facility is not repaired and the dryer system remains offline.
- Scenario 2: The existing dryer facility is repaired and returned to operation. According to the HFCAWTP Biosolids Processing Assessment Report, this would require a capital investment of approximately $9.5 million.

Outlined in **Table 6-5** are the estimated gross revenues for each alternative, annualized over the capital amortization period, for dryer scenario one. The source of revenue varies depending on the alternative. Alternatives 1 and 3 provide revenue from energy production while Alternatives 5 ,5a and 7 provide savings from a natural gas offset, Alternative 5 only provides savings if the dryer is operational.

Table 6-5
Annualized Revenues/Savings Generated by Each Alternative for Dryer Scenario 1: Dryer Offline

	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue
Alternative 1	$1,910,738	$236,861
Alternative 3	$1,910,738	$236,861
Alternative 5	$0	$236,861
Alternative 5a	$0	$236,861
Alternative 7	$0	$258,902
Current System	$1,137,859	$258,902

Table 6-5 shows that Alternative 7 and the current system both have a greater annualized natural gas benefit even though all the alternatives generate this revenue from offsetting digester heating needs in dryer scenario one. This additional value is generated because Alternative 7and the current system do not have any required capital improvements and generate a natural gas offset revenue in year one of the net present worth analysis that was detailed in Section 6.2.1.

Table 6-6 outlines the estimated revenues for each alternative in dryer scenario 2, annualized over the capital amortization period.

Table 6-6
Annualized Revenues/Savings Generated by Each Alternative for Dryer Scenario 2: Dryer Operational

	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue
Alternative 1	$1,910,738	$236,861
Alternative 3	$1,910,738	$583,917
Alternative 5	$0	$1,317,538
Alternative 5a	$0	$1,009,296
Alternative 7	$0	$258,902
Current System	$1,137,859	$258,902

As shown in Table 6-6, Alternatives 3, 5, and 5a have additional natural gas offset revenues, this is because these alternatives can offset more natural gas use if the dryer system is repaired and operational. Alternatives 1, 7, and the current system did not change from Dryer Scenario 1 because the status of the dryer system has no effect on their generated revenue.

6.3 Economic Analysis Summary

To summarize the value of each alternative, a “net benefit” was calculated. To determine the net benefit for each alternative, the annualized capital and O&M costs were subtracted from the annualized revenues. **Tables 6-7** and **6-8** show the capital costs, labor costs, parts/materials cost, electricity revenue, natural gas offset revenue and the net benefits for each alternative, in both dryer scenarios. These costs and revenues were annualized over the 20 year capital amortization period. Costs shown in "red" represent a negative number, and essentially reduce overall Annualized Net Benefit amounts.

Table 6-7
Annualized Net Benefits for Dryer Scenario 1: Dryer Offline

Alternative	Annualized Capital Costs	Annualized Labor Cost	Annualized Material Cost	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue	Annualized Net Benefit
Alternative 1	($691,930)	($438,038)	($180,955)	$1,910,738	$236,861	$836,676
Alternative 3	($948,485)	($438,038)	($186,570)	$1,910,738	$236,861	$574,506
Alternative 5	($361,603)	($50,534)	($44,919)	$0	$236,861	($220,195)
Alternative 5a	($117,716)	($50,534)	($44,919)	$0	$236,861	$23,693
Alternative 7	$0	($36,824)	($42,961)	$0	$258,902	$179,116
Current System	$0	($589,860)	($395,243)	$1,137,859	$258,902	$411,657

Table 6-8
Annualized Net Benefits for Dryer Scenario 2: Dryer Operational

Alternative	Annualized Capital Costs	Annualized Labor Cost	Annualized Material Cost	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue	Annualized Net Benefit
Alternative 1	($691,930)	($438,038)	($180,955)	$1,910,738	$236,861	$836,676
Alternative 3	($948,485)	($438,038)	($186,570)	$1,910,738	$583,917	$921,562
Alternative 5	($361,603)	($50,534)	($44,919)	$0	$1,317,538	$860,483
Alternative 5a	($117,716)	($50,534)	($44,919)	$0	$1,009,296	$796,128
Alternative 7	$0	($36,824)	($42,961)	$0	$258,902	$179,116
Current System	$0	($589,860)	($395,243)	$1,137,859	$258,902	$411,657

Table 6-7 shows, under Dryer Scenario 1, that all of the alternatives provide a net benefit except Alternative 5 (under Alternative 5 the annualized capital costs are greater than the generated annualized revenues). Alternative 1 has the greatest net annual benefit at a value of $836,676, due to increased electricity production from new, more efficient CHP engines. It should be noted that Alternatives 5 and 5a would operate the same as

Alternative 7 if the dryer were not operational. The current system provides a net annualized benefit of $411,657, indicating the current system provides an overall positive value to the City.

Given that the annualized capital costs are included in the annual net benefit calculation, each of the alternatives (except for Alternative 5) provide a positive net benefit and offer an immediate return on capital funds invested. Regardless of the dryer's operational status, Alternative 1 provides an increase in annual net benefit of $425,019 over the current system ($836,676 minus $411,657). This is due to reduced maintenance costs and greater electricity production associated with new, more efficient CHP engines.

Under Dryer Scenario 2, as shown in Table 6-8, Alternative 3 offers the greatest net benefit followed by Alternatives 5 and 5a. Alternative 3 offers the greatest net benefit due to the revenues generated from both electricity production and natural gas offset in the dryer. It is important to remember however, that these benefits can only be obtained by Alternatives 3, 5, and 5a if the dryer is repaired at an additional cost of roughly $9.5 million.

7.0 Regulatory Issues

7.1 Air Permitting

The HFCAWTP currently has a Title V air operation permit (Permit No. 0570373-018-AV) granted by the Environmental Protection Commission of Hillsborough County (EPC). The Title V permit will expire on November 1, 2016. No modifications to the permit will be required if the current system is maintained. A copy of the air permit is included in **Appendix A**.

The current air permit states that the existing engines must comply with the emissions standards of 40 CFR Subpart ZZZZ by October 19, 2013. MWH spoke with Kelly Boatwright, Air Permitting Director, and Dave Zell at FDEP and determined that there are no emissions standards in Subpart ZZZZ that would apply to the City's existing biogas fueled engines. This means that under current regulations, the City's existing engines can be run indefinitely. This would also apply to any future renewals of the air permit as long as current regulations remain in effect.

If the existing engines are replaced as per Alternative No. 1 or No. 3, an Air Construction permit will need to be obtained from EPC in order to modify the Title V permit. No modification will be required to the permit with regards to the dryer facility as Alternative No. 3 does not alter the permitted operations procedure of the dryer. The dryer is currently permitted to run on the exhaust of the existing TECO engines. Costs for the required permits and the estimated annual emission fees are presented in **Table 7-1**, below.

Table 7-1
Estimated Permitting Fees

Permit Requirement	Fees
Air Construction Permit	$ 1,000
Air Permit Modification	$ 0
Annual Emission Fees from New CHP Engines	$ 1,600(1)

(1)Estimate, based on Waukesha APG-1000 engines fueled by biogas with a heating value of 500 BTU

New biogas fueled engines would have to comply with emissions regulations as outlined in 40 CFR Subpart JJJJ. These requirements can be met by new engines provided that the biogas supply meets the engine manufacturer's specification. This report assumes a new biogas conditioning system would be provided for all engine alternatives. The emissions requirements of 40 CFR subpart JJJJ are shown in **Table 7-2**, below.

Table 7-2
Emissions Requirements CFR 40 Subpart JJJJ

Emissions Parameter	Limit
Nitrous Oxides (NO_x)	2.0 g/HP-hr
Carbon Monoxide (CO)	5.0 g/HP-hr
Volatile Organic Compounds (VOC)	1.0 g/HP-hr

(1)Estimate, based on Waukesha APG-1000 engines fueled by biogas with a heating value of 500 BTU

In order to implement either Alternative No. 5 or 5a, the existing Title V permit will have to be modified with respect to the dryer facility. The dryer facility is currently permitted to use natural gas or engine exhaust as a heat source. The modifications for these alternatives would also remove the biogas fueled engines from the permit. All of these required modifications could be made through an Air Construction Permit from EPC.

Currently, the biogas flares are not regulated by the Title V permit as they are used only on an emergency basis. Alternative 7 would require an Air Construction Permit from EPC to modify the current Title V permit and annual emission fees would need to be recalculated based on the flaring of raw biogas.

The EPC recommends that a pre-application meeting be conducted for any air construction permits in order to expedite and simplify the application process. This meeting would include representatives from every division at EPC to insure that all regulations are adhered to.

7.2 Biosolids Disposal

Regulations concerning the disposal of biosolids are a primary concern for the City of Tampa. Currently, the City's biosolids are dewatered and land applied as Class B biosolids at approved sites by a subcontracted hauling company

At the federal level, land application of biosolids is regulated by the Environmental Protection Agency (EPA). The EPA requires that biosolids conform to Part 503 which sets risk-based limits for pathogens and other pollutants. While biosolids produced at HFCAWTP do conform to Part 503 and there have been no proposed changes to the rule at the federal level, trends regarding state and local regulations for land application could be of concern.

According to a report titled “Charting the Future of Biosolids Management: Final Report”, prepared for the Water Environment Federation in May of 2011, state and county regulations have begun to discourage Class B land application. In Texas, regulations concerning Class B land application have resulted in a decrease in land application of 75%. In both California and Georgia, counties have begun to regulate the land application of biosolids. Some counties have enacted complete bans, others have implemented more stringent permit requirements, and others have changed nothing from EPA Part 503.

The June 2011 issue of the Florida Water Resources Journal reports that, by the end of 2013, the State of Florida will enact watershed-based regulations for land application of biosolids. These new regulations stem from concerns surrounding nutrient loading and land application of biosolids. These regulations will create tighter restrictions for some sites while completely eliminating numerous land application sites across the state.

As the regulations currently stand, land application is a viable and cost-effective disposal method for the City. If land application were phased-out and no longer available, the City would either have to landfill their biosolids or produce marketable Class A biosolids.

According to the HFCAWTP Biosolids Processing Assessment Report, production of Class A biosolids would be more cost-effective than landfilling biosolids at current natural gas prices. Determining the best method of biosolids disposal into the future will require further study regarding trends in energy costs, tipping fees, and disposal regulations.

8.0 Conclusions and Recommended Project

8.1 Conclusions

In evaluating biogas utilization alternatives for the City of Tampa at the Howard F. Curren Advanced Wastewater Treatment Plant, seven alternatives were presented to the City and five preferred alternatives were chosen for economic evaluation. These five preferred alternatives were compared against the current biogas utilization system. Those five alternatives included:

Alternative 1 - Replacing the five existing biogas engines at HFCAWTP with three new 1000 kW CHP engines located in the existing generator building. Heating needs in the anaerobic digesters would be met by heat recovered from the three new CHP engines.

Alternative 3 - Replacing the five existing 500 kW engines at HFCAWTP with three new 1000 kW CHP engines located in the existing TECO building, allowing for engine exhaust to be used to supplement natural gas requirements in the dryer facility. Heating needs in the anaerobic digester would be met by hot water recovered from the dryer facility.

Alternative 5 - Eliminate the five existing 500 kW engines at HFCAWTP and route all of the biogas to the existing dryer facility. Heating needs in the anaerobic digesters would be met hot water recovered from the dryer facility.

Alternative 5a - Eliminate the five existing 500 kW engines at HFCAWTP and use biogas to meet the heating needs of the anaerobic digesters. Any excess biogas would be routed to the existing dryer facility to offset natural gas use.

Alternative 7 - Eliminate the five existing 500 kW engines at HFCAWTP, fuel the digester boilers with biogas and flare the excess biogas.

Section 6 presented the economic evaluation of the preferred alternatives listed above, as well as the operation of the current biogas utilization system at HFCAWTP. At the request of the City, two scenarios were evaluated for each of the alternatives; Scenario 1 assumed that the dryer facilities remain offline while Scenario 2 assumed that the dryer facilities were repaired and operational. The following assumptions were made in the economic analysis:

- Dewatering improvements. This work is already in the planning stages and a budget has been allocated in the City of Tampa's Capital Improvement Program (CIP); this requirement is common to all alternatives and the costs will not be included in this analysis.
- Dryer facility repair: Dryer facility repairs are not within the scope of this study and the costs associated with the repair are not included, though it should be noted that the repairs are necessary for Alternatives 3, 5, and 5a to produce maximum revenue from natural gas offset.
- Biosolids dewatering and disposal costs are also outside the scope of this project and are not included in this economic evaluation

The economic analysis conducted for this report presents annualized costs and benefits for each of the preferred alternatives. These annualized values allow for inflation and the time value of money to be considered. In order to calculate the annualized values, costs and revenues for each alternative were estimated for FY2012 and then increased by the specified inflation rate of 2.5% over 20 years, to coincide with the capital cost amortization period. These annual costs were then equated to a net present worth which was annualized over the same 20 year period using a 5% interest rate. An example of this calculation is shown in Section 6.2.1.

Estimated capital costs for each of the alternatives are shown in **Table 8-1,** below. Annualized revenues, from electricity production and natural gas offset, for each alternative are shown in **Table 8-2** and **8-3**; and a summary of the economic analysis for each dryer scenario is outlined in **Table 8-4** and **Table 8-5**.

Table 8-1
Capital Cost Estimates

Alternative	Capital Cost	Annualized Capital Cost
Alternative 1	$ 8,622,975	$ 691,930
Alternative 3	$ 11,820,225	$ 948,485
Alternative 5	$ 4,506,375	$361,603
Alternative 5a	$ 1,467,000	$ 117,716
Alternative 7	$ 0	$ 0
Current System	$ 0	$ 0

Note: Annualized value calculation is explained in Section 6.2.1

Table 8-2
Annualized Revenues/Savings Generated by Each Alternative for Dryer Scenario 1: Dryer Offline

	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue
Alternative 1	$1,910,738	$236,861
Alternative 3	$1,910,738	$236,861
Alternative 5	$0	$236,861
Alternative 5a	$0	$236,861
Alternative 7	$0	$258,902
Current System	$1,137,859	$258,902

Table 8-3
Annualized Revenues/Savings Generated by Each Alternative for Dryer Scenario 2: Dryer Operational

	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue
Alternative 1	$1,910,738	$236,861
Alternative 3	$1,910,738	$583,917
Alternative 5	$0	$1,317,538
Alternative 5a	$0	$1,009,296
Alternative 7	$0	$258,902
Current System	$1,137,859	$258,902

Table 8-4
Annualized Net Benefits for Dryer Scenario 1: Dryer Offline

Alternative	Annualized Capital Costs	Annualized Labor Cost	Annualized Material Cost	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue	Annualized Net Benefit
Alternative 1	($691,930)	($438,038)	($180,955)	$1,910,738	$236,861	$836,676
Alternative 3	($948,485)	($438,038)	($186,570)	$1,910,738	$236,861	$574,506
Alternative 5	($361,603)	($50,534)	($44,919)	$0	$236,861	($220,195)
Alternative 5a	($117,716)	($50,534)	($44,919)	$0	$236,861	$23,693
Alternative 7	$0	($36,824)	($42,961)	$0	$258,902	$179,116
Current System	$0	($589,860)	($395,243)	$1,137,859	$258,902	$411,657

Table 8-5
Annualized Net Benefits for Dryer Scenario 2: Dryer Operational

Alternative	Annualized Capital Costs	Annualized Labor Cost	Annualized Material Cost	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue	Annualized Net Benefit
Alternative 1	($691,930)	($438,038)	($180,955)	$1,910,738	$236,861	$836,676
Alternative 3	($948,485)	($438,038)	($186,570)	$1,910,738	$583,917	$921,562
Alternative 5	($361,603)	($50,534)	($44,919)	$0	$1,317,538	$860,483
Alternative 5a	($117,716)	($50,534)	($44,919)	$0	$1,009,296	$796,128
Alternative 7	$0	($36,824)	($42,961)	$0	$258,902	$179,116
Current System	$0	($589,860)	($395,243)	$1,137,859	$258,902	$411,657

The following is a summary of the conclusions made based on the economic analysis presented previously:

- Alternative 1 provides the greatest net benefit if the dryer is out of operation, largely because of the revenue generated from increased electricity production.
- Alternative 3 has the greatest net benefit if the dryer is operational because it produces the same amount of electricity as Alternative 1 as well as offsets natural gas use in the dryer
- Regardless of the operational status of the dryer, Alternative 1 provides a $425,019 increase in net benefit over the current system.
- Alternatives 5, 5a and 7 have the lowest net benefit in both dryer operational scenarios, and are considered impractical for the following reasons:
    - Flaring provides the lowest annual net benefit as there is no electricity production and natural gas offset is minimal.
    - Flaring does not utilize all of the stored energy in the biogas, a readily available resource at the plant.
    - Producing electricity is more advantageous and economical than offsetting or supplementing natural gas based on current natural gas prices.
- The current biogas filter units at HFCAWTP are not providing any benefit to the City and may actually degrade the quality of the biogas produced at the plant, this has greatly increased the required maintenance costs to operate the current engines.

8.2 Recommendations

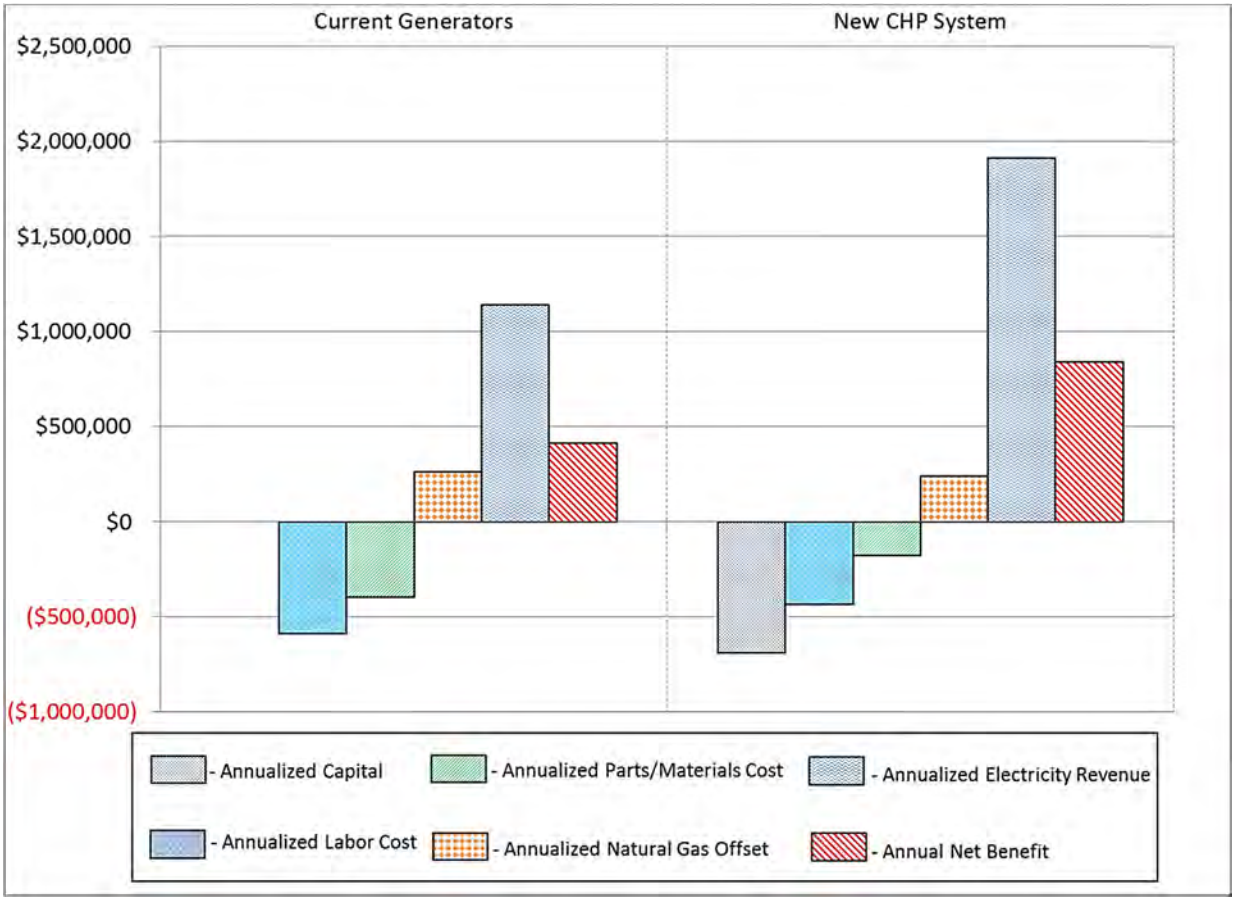
It is recommended that the City of Tampa replace their five existing biogas fueled engines with three new (3) 1,000 kW engines. New engines will reduce maintenance costs and will increase revenues due to greater efficiencies in engine design. Alternative 1 is the most cost-effective, feasible alternative for the City. These improvements can be phased in over the next 20 years.

It is also recommended that the City replace its current biogas conditioning system in the next 1-3 years. As was discussed in Section 3, the current filter units at HFCAWTP are not providing any benefit to the City and may actually degrade the quality of the biogas produced at HFCAWTP. The costs of a new biogas treatment system have been included in the capital cost estimate of this recommendation.

Discussions with City Staff regarding the dryer facility indicate that the repairs necessary for operation will only be made if land application regulations or other market drivers require a Class A biosolids product for disposal/reuse. The economic evaluation done in this study confirms that repairing the dryer facilities is not cost effective as long as low cost Class B land application is a viable option for disposal; and as presented in Section 7, it does not seem that regulations concerning biosolids disposal are going to eliminate land application in the immediate future. Given this information, Alternative 1, Scenario No. 1 is recommended as the best project for the City.

In order to demonstrate the financial benefit of this capital investment, the recommended alternative was compared to the current engine operation. **Figure 8-1** shows the capital cost, labor cost, materials cost, revenues, and net benefit for both Alternative 1 and the current system annualized over the 20 year capital amortization period.

Figure 8-1: Comparison of Alternative 1 and Current System



Below, **Table 8-6** shows the information provided in Figure 8-1 as well as the payback period for the recommended alternative. As shown, the capital investment of $8.6 million, $691,930 annually, provides substantial benefits to the City:

- $151,822 decrease in labor costs annually
- $750,839 increase in revenue generated annually

The benefits provided by the recommended upgrades will yield a $425,019 increase in net annual benefit over the current biogas utilization system.

Table 8-6
Comparison of Alternative 1 and Current System

	Current System	Alternative 1
Annual Capital Cost(1)	$ 0	$691,930
Annual Labor Cost(1)	$589,860	$438,038
Annual Parts/Materials Cost(1)	$395,243	$180,955
Annual Revenue Generated(1)	$1,396,760	$2,147,599
Annual Net Benefit(1)	$411,657	$836,676

(1)All values shown are annualized values over the 20 year capital amortization period

As the capital cost is amortized over a 20 year period, Alternative 1 provides a positive net benefit from year one.

8.2.1 Description of Recommended Project

It is recommended that the City of Tampa replace their five existing biogas fueled engines with three new 1,000 kW CHP engines. Waste heat from these new CHP engines will be used to heat the digesters. Alternatives 1 and 3 are both feasible alternatives for the City and the capital costs of each alternative are within an acceptable range. It is also recommended that the City replace its current biogas conditioning system.

The recommended project includes the following facilities and components:

- CHP Engine Packages – Three new 1000 kW CHP engines (Waukesha APG 1000 or equivalent). Example specification sheets are included in **Appendix C**.

- New Biogas Conditioning Equipment- Package biogas conditioning system (Robinson Group or equivalent) that includes blowers and instrumentation. Robinson Group's proposal is included in **Appendix C**.
- Existing Engine Demolition. The 5 existing engines housed in the generator building and the raw sewage pumping station will be removed.
- Biogas Piping-Biogas piping will consist of modifications to existing piping in order to connect new CHP engines as well as repairs to leaky joints as mention in the condition assessment in Section 3.
- Waste Heat (water) Piping- Waste heat piping will consist of modifications to existing piping in order to connect new CHP engines
- Natural Gas Pipeline Extension- City staff indicated that they would like to have the ability to run natural gas in the CHP engines for maintenance purposes.
- Electrical & Instrumentation- Existing electrical and instrumentation needs to be evaluated during the design phase to determine what modifications will be required.

8.2.2 Schematic of Recommended System

A simplified schematic of the recommended Alternative 1, Scenario No. 1 is shown in **Figure 8-2.**

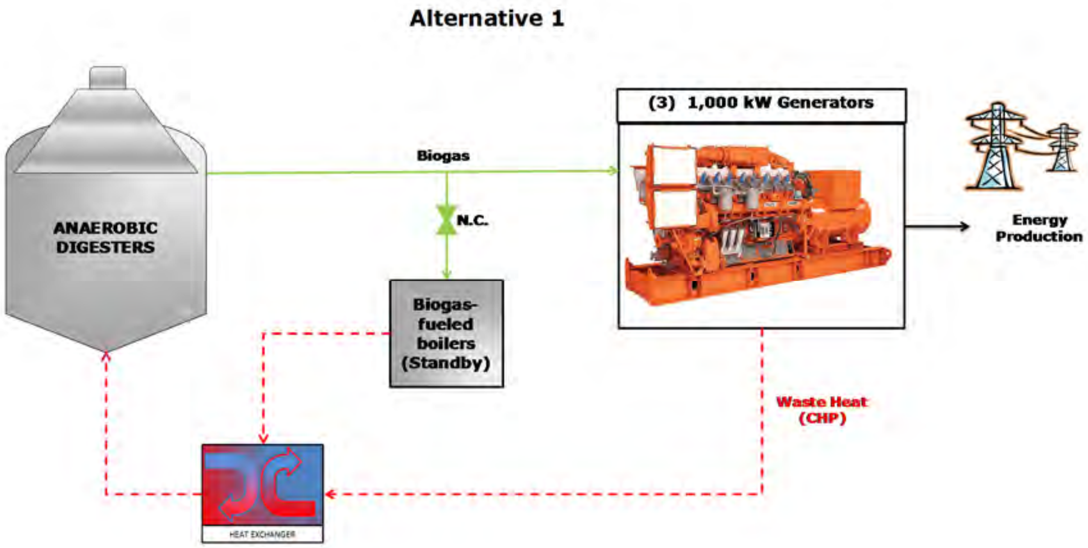


Figure 8.2: Conceptual Schematic of Alternative 1

8.2.3 Conceptual Site Layout

Figure 8-3 shows a conceptual site plan for the recommended project, replacing the three 500 kW engines housed in the generator building with three new 1000 kW CHP engines. The other two existing engines (No. 1 and No. 2) housed in the Raw Sewage Pumping Station will be demolished.

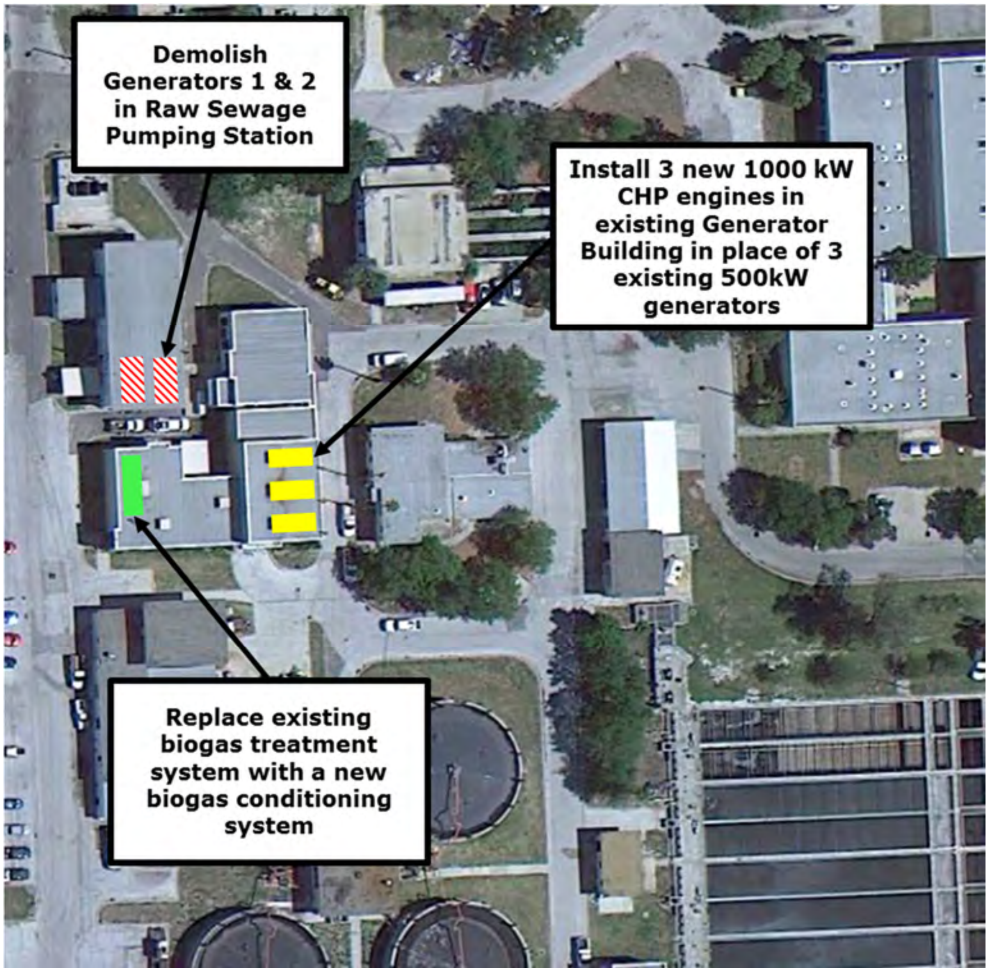


Figure 8.3: Conceptual Site Plan, Alternative 1

8.2.4 Conceptual Cost Estimates

The required equipment, facility upgrades and the estimated capital costs for the recommended project are outlined in **Table 8-7**. The line item in the capital cost for estimate for "Natural Gas Pipeline Extension" is provided to route natural gas pipeline to the new CHP engines. Plant staff expressed a need for this as the natural gas could be used on a periodic basis to "flush-out" the engines. The routing of the natural gas piping needs to be investigated under the preliminary design phase of this project.

Table 8-7
Capital Cost Estimate, Alternative 1, Scenario No. 1

Item	Unit Cost	Cost Unit	Qty.	Cost
CHP Engine Packages	$ 1,092,000	EA	3	$ 3,276,000
Gas Conditioning	$ 1,500,000	LS	1	$ 1,500,000
Existing Engine Demolition	$ 180,000	LS	1	$ 180,000
Biogas Piping	$ 95	LF	150	$ 14,250
Waste Heat (water) Piping	$ 350	LF	100	$ 35,000
Natural Gas Pipeline Extension	$ 90	LF	300	$ 27,000
Electrical & Instrumentation	15%	%		$ 716,400
Subtotal				**$ 5,748,650**
Engineering & Administration	20%	%		$ 1,149,730
Contingency	30%	%		$ 1,724,595
Total				**$ 8,622,975**

Utilizing the existing generator building and engine pads will minimize the necessary piping for the biogas and water jacket systems. The new gas conditioning system can be located in place of the eight existing filter kettles, again minimizing the necessary materials to incorporate the new design. **Figure 8-4**, below, shows probable placement options for both the new CHP engines and the new gas conditioning system in the existing generator building.

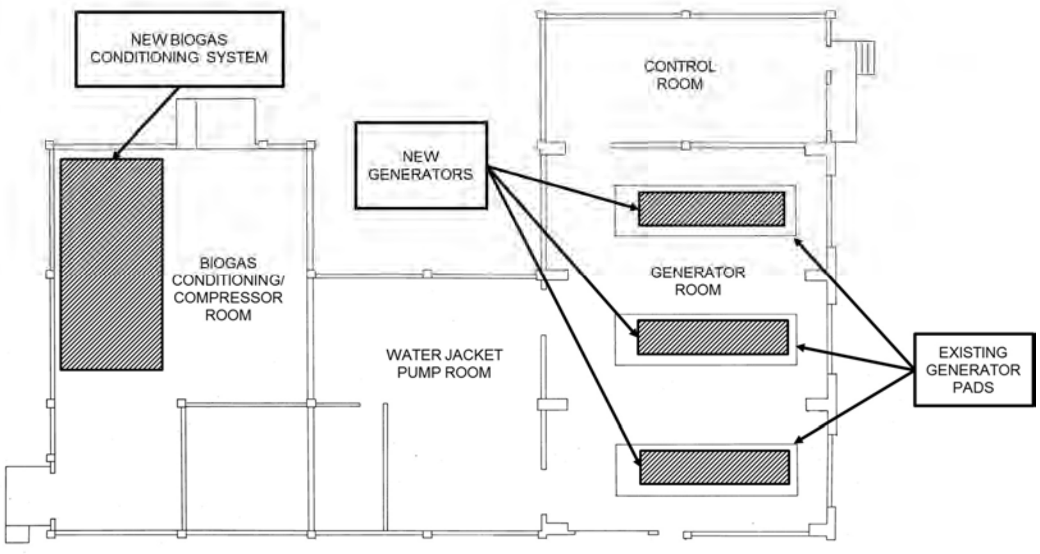


Figure 8-4: Placement of required equipment in existing generator building

8.2.5 Project Funding

8.2.5.1 Phasing

In order to lessen the fiscal burden of this project, the capital improvements could be phased over several fiscal years. Given that the current engines can be run past the Subpart ZZZZ compliance date, it is recommended that the City operate the existing engines until the three new CHP engines are installed. The recommended project should be implemented as quickly as possible to maximize the benefits of the capital investment.

The first phase of this project must include the biogas conditioning system as it will extend the life of the current engines and will protect the new CHP engines once they are installed. The first phase should also include 1 new CHP engine to replace the existing, inoperable engine if capital funds are available.

Phases 2 and 3 of this project should include replacement of existing engines with 2 additional new CHP engines. **Table 8-8** shows the recommended phasing for this project.

Table 8-8
Recommended Phasing of Project

Year	Components of Project	Capital Cost
Immediate	• New Biogas Conditioning System (Robinson Group or equal) • Demolition of existing biogas conditioning system	$2,587,000
FY 2014/15	• (1) 1000 kW CHP engine package (Waukesha APG 1000 or equal) • Biogas piping connections to new engine • Waste heat piping connections to new engine • Natural gas pipeline to existing generator building and connections to new engine • Demolition of (1) existing engine	$ 1,976,000
FY 2018/19	• (1) 1000 kW CHP engine package (Waukesha APG 1000 or equal) • Biogas piping connections to new engine • Waste heat piping connections to new engines • Natural gas piping connections to new engine • Demolition of (1) existing engine	$ 1,976,000
FY 2020/22	• (1) 1000 kW CHP engine package (Waukesha APG 1000 or equal) • Biogas piping connections to new engine • Waste heat piping connections to new engines • Natural gas piping connections to new engine • Demolition of 3 remaining existing engines	$ 2,084,000

Note: Capital costs are for 2013 and have not been increased due to inflation

8.2.5.2 Grants

The City should also examine the possibility of grant funding. Grant funding may allow the City to implement the recommended capital improvements in a shorter amount of time, providing the most benefit to the City. The U.S. Department of Energy's Energy and Efficiency and Conservation Block Grant Program may provide some benefit to the City as well as these energy grant programs from the State of Florida:

- **Shovel Ready Energy Project Grants**

  Provides funding to competitively-selected renewable energy and energy efficiency technology projects that are "shovel-ready".

- **Florida Clean Energy Grants**

  Provides funding to promote energy efficiency measures and renewable energy deployment for eligible public, not-for-profit, and agricultural entities.

- **Florida Energy Opportunity Fund**

  Direct investment program created to promote the adoption of energy efficient and renewable energy products and technologies in Florida and requires that funds be used primarily for: facility and equipment improvement with EE/RE products, acquisition or demonstration of renewable energy products, and improvement of existing production, manufacturing, assembly or distribution processes to reduce consumption or increase the efficient use of energy in such processes

MWH

Howard F. Curren AWTP

Biogas Use Study

JUNE 2013

APPENDIX A

City of Tampa – Wastewater Department
Howard F. Curren AWT Plant

Facility ID No. 0570373
Hillsborough County

Title V Air Operation Permit Renewal

FINAL Permit No. 0570373-018-AV
(Renewal of Title V Air Operation Permit No. 0570373-017-AV)

Permitting and Compliance Authority:

Environmental Protection Commission of Hillsborough County
3629 Queen Palm Drive
Tampa, FL 33619
Telephone: (813) 627-2600
Fax: (813) 627-2660

Title V Air Operation Permit Renewal

FINAL Permit No. 0570373-018-AV

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PERMITTEE:
Anthony Kasper, P.E., Director
City of Tampa – Wastewater Department
306 East Jackson St.
Tampa, FL 33602

FINAL Permit No.: 0570373-018-AV
Facility ID No.: 0570373
SIC No.: 4952
Project: Title V Air Operation Permit Renewal

The purpose of this project is to renew the existing Title V permit for the above referenced facility, as well as to incorporate Permit No. 0570373-019-AC to include the existing digester gas generator engines as regulated emission units, which are subject to 40 CFR 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE). This facility is located at 2700 Maritime Boulevard, Tampa, Hillsborough County; UTM Coordinates: Zone 17, 364.00 East and 3089.5 North; Latitude: 27° 55’ 20” North and Longitude: 82° 26’ 20” West.

The Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213. The above named permittee is hereby authorized to operate the facility in accordance with the terms and conditions of this permit.

Effective Date: November 1, 2011
Renewal Application Due Date: March 21, 2016
Expiration Date: November 1, 2016

Richard D. Garrity, Ph.D.
Executive Director

RDG/SRH/srh

Subsection A. Facility Description.

The regulated emissions units at this wastewater treatment plant consist of two sludge dryer trains, five sludge storage silos, two truck loading stations with three truck loading spouts, four emergency diesel generators, two natural gas fired generators, five digester gas fired generators, and a methanol storage tank. The sludge drying facility consists of two identical sludge dryer trains (No. 2 and No. 3) operating in parallel with separate but identical process and control equipment. The sludge stream from wastewater treatment is chemically treated then mechanically pressed with belt filter presses to raise the solids content from approximately 1-2% to around 20%. The sludge cake then moves via conveyor over belt scales to a wet storage bin. The sludge then goes to a pug mill where the water content is lowered further by mixing it with dry, recycled sludge from a recycle bin. From the pugmill, the sludge is fed into a natural gas fired rotary dryer, a settling chamber, and a Sweco screen for sizing. Oversized sludge particles go to a crusher and then to the recycle bin. Undersized sludge is sent directly to the recycle bin. The properly sized sludge is conveyed to the four sludge storage silos (Silo Nos. 2, 3, 4, and 5). From the four storage silos, the sludge is either loaded onto trucks at one of two loading stations (Station Nos. 1 and 2), directed to a fifth storage silo (Silo No. 6) with a dedicated loading spout, sent to the recycle bin, or routed back to the four main storage silos.

Particulate matter emissions from each sludge drying train are controlled with a cyclone and a venturi scrubber that includes a cyclonic separator. Volatile organic compound emissions are controlled with a natural gas fired regenerative thermal oxidizer operating in series with the particulate control devices. Emissions from each storage silo and truck loading station are controlled with fabric filters. Odors from the sludge drying building are controlled by two spray mist scrubbers which use a sodium hypochlorite and water solution. One scrubber operates at a time with the other serving as a back-up.

Electricity for the facility is normally supplied by Tampa Electric Company and the five digester gas generators (0.5 MW each). However, two natural gas fired generators can be used as standby emergency power as well as supplemental generation that will be dispatched to the grid for Tampa Electric Company. These generators have been identified as Engine Nos. 1 and 2. These emission units are two identical Waukesha 16V-AT27GL engines, 4 stroke, spark ignition, each rated at 4,073 bhp, fired exclusively on natural gas, each coupled to a nominal 2.9 MW electrical generator. The maximum heat input rate is 27.2 MMBTU/hr (HHV) based on natural gas heating value of 1025 Btu/cf. In addition, this facility has four diesel fired emergency generators on-site. The emergency generator engines are four Caterpillar 3516 DITA engines, 4 stroke compression ignition, rated at 2,847 bhp, and are fired on No. 2 diesel fuel at a maximum rate of 137.5 gallons/hr. The five digester gas generator engines are five Waukesha VHP-L7042 GU engines, 4 stroke spark ignition, rated at 670.5 bhp, fired exclusively on digester gas. The maximum heat input rate is 5.6 MMBtu/hr based on a digester gas heating value of 621 Btu/cf and a fuel flow rate of 9,000 cf/hr. Also on site are four 3.2 MMBtu/hr Bryan Flexible Tube emergency boilers for the digester generators in the rare event that the digester generators are not in service. These boilers are being included on the insignificant emission unit list since the PTE's are below the exemption threshold for individual emission units.

An alternate method of operation of Sludge Dryer Train Nos. 2 and 3 is the heat recovery mode. This mode utilizes the waste heat in the exhaust gases from Engine Nos. 1 and 2 to offset the heat normally generated by firing natural gas in a combustion chamber for the dryers. The exhaust gas from Engine 1 can only feed Sludge Dryer Train No. 3 and Engine 2 can only feed Sludge Dryer Train No. 2. Even though a different heat source is used in the heat recovery mode, the flow rate through each rotary dryer is the same as that under normal operations. Additional heat can be added to handle the varying moisture content of the sludge by the combustion of natural gas in the existing combustion chamber.

Methanol is used as a feedstock for the biological denitrification stage of the wastewater treatment process. The methanol is delivered on a daily to weekly basis by truck or railcar to a fixed roof storage tank with a volume of approximately 95,000 gallons. Methanol is considered a VOC and HAP, and emissions are generated by evaporative losses (breathing and working losses) through the venting of displaced air through the “J” neck vent located on the roof of the tank. Minimal emissions are also generated from evaporation of methanol in the denitrification stage and from the fugitive losses of handling methanol through the piping, valves, flanges, etc. VOC and HAP emissions, which includes methanol, will be controlled by limiting the product throughput and submerged filling pursuant to Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards.

CAM does apply to the control systems (cyclones, scrubbers, oxidizers) for Sludge Dryer Train Nos. 2 and 3 for VOC and PM. This sludge drying facility is subject to 40 CFR 61, Subpart E - National Emission Standard for Mercury and Rule 62-296.700, F.A.C. (PM-RACT). The engines at the facility are subject to 40 CFR 63 Subpart ZZZZ, and are not subject to 40 CFR 60 Subpart IIII nor Subpart JJJJ due to the date of construction of the engines.

Also included in this permit are miscellaneous insignificant emissions units and/or activities.

Based on the Title V Air Operation Permit Renewal application received November 12, 2010, this facility is not a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Units.

EU No.	Brief Description
Regulated Emissions Units	
001	Wastewater Treatment Plant Sludge Dryer Train No. 2
002	Wastewater Treatment Plant Sludge Dryer Train No. 3
005	Sludge Silo No. 2
006	Sludge Silo No. 3
007	Sludge Silo No. 4
008	Sludge Silo No. 5
009	Truck Loading Station No. 1
010	Truck Loading Station No. 2
011	Sludge Silo No. 6
012	Four Emergency Diesel Generators
016	Silo No. 6 Truck Loading Spout
017	Engine 1 with Nominal 2.9 MW Generator
018	Engine 2 with Nominal 2.9 MW Generator
019	Methanol Storage Tank
020	Five Digester Generator Engines
Unregulated Emissions Units (See Appendix U-1)	
003	Building Fugitives and Odor Control System No. 1
004	Building Fugitives and Odor Control System No. 2

Subsection C. Applicable Regulations.

Based on the Title V air operation permit renewal application received November 12, 2010, this facility is not a major source of hazardous air pollutants (HAP). Because this facility operates stationary reciprocating internal combustion engines, it is subject to regulation under 40 CFR 63, Subpart ZZZZ, - National Emissions Standards For Hazardous Air Pollutants For Stationary Reciprocating Internal Combustion Engines. A summary of applicable regulations is shown in the following table.

Regulation	**EU No(s).**
40 CFR 63, Subpart A, NESHAP General Provisions	012, 017, 018, 020
40 CFR 63, Subpart ZZZZ - National Emissions Standards For Hazardous Air Pollutants For Stationary Reciprocating Internal Combustion Engines	012, 017, 018, 020
40 CFR 61, Subpart E -National Emission Standard for Mercury	001, 002
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration and BACT for NO_x	017, 018
Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards	001, 002, 003, 004, 012, 017, 018, 019, 020
Rule 62-296.711, F.A.C. - Materials Handling, Sizing, Screening, Crushing and Grinding Operations (RACT Particulate Matter)	005, 006, 007, 008, 009, 010, 011, 016
Rule 62-296.712, F.A.C. - Miscellaneous Manufacturing Process Operations (RACT Particulate Matter)	001, 002

The following conditions apply facility-wide to all emission units and activities:

FW1. Appendices. The permittee shall comply with all documents identified in Section IV, Appendices, listed in the Table of Contents. Each document is an enforceable part of this permit unless otherwise indicated. [Rule 62-213.440, F.A.C.]

Emissions and Controls

FW2. Not federally Enforceable. Objectionable Odor Prohibited. No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rule 62-296.320(2) and 62-210.200(Definitions), F.A.C.]

FW3. General Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed-necessary and ordered by the Department.
[Rule 62-296.320(1), F.A.C.]

FW4. General Visible Emissions No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

FW5. Unconfined Particulate Matter No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction; alteration; demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

i. Paving and maintenance of roads, parking areas and yards.
ii. Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities.
iii. Sweeping and removal of fugitive product at the truck loadout area on an as needed basis.
iv. Limiting vehicular traffic to 20 MPH.
v. Landscaping or planting of vegetation.
vi. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
vii. Ducting the dryer trains, silos, and truck loading to the associated control equipment.
viii. Enclosing and venting to a control device all conveyor belts and connectors that handle dry material, with the exception of the recirculation (overheated product) conveyor used in emergencies to prevent overheating of the silos. The recirculation conveyor must remain covered with the belt transfer point vented to Truck No. 1 (EU 009) baghouse when in use.
ix. Practicing good housekeeping of facility grounds.

[Rule 62-296.320(4)(c), F.A.C.]

Annual Reports and Fees

See Appendix RR, Facility-wide Reporting Requirements for additional details.

FW6. Annual Operating Report The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by April 1st of each year. [Rule 62-210.370(3), F.A.C.]

FW7. Annual Emissions Fee Form and Fee The annual Title V emissions fees are due (postmarked) by March 1st of each year. The completed form and calculated fee shall be submitted to: Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070. The forms are available for download by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm. [Rule 62-213.205, F.A.C.]

FW8. Annual Statement of Compliance The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit within 60 days after the end of each calendar year during which the Title V permit was effective. [Rules 62-213.440(3)(a)2. & 3. and (3)(b), F.A.C.]

FW9. Prevention of Accidental Releases (Section 112(r) of CAA) The permittee shall comply with the Risk Management Plan as follows:

a. Submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038, Telephone: (703) 227-7650.

b. Submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.

[40 CFR 68]

FW10. In order to establish the facility as a non-Title V source for Hazardous Air Pollutants (HAP), the HAP, as defined in Rule 62-210.200, F.A.C., emissions shall be less than 10 tons in any 12 consecutive month period for any individual HAP, and less than 25 tons in any 12 consecutive month period for any combination of HAPs. [Rule 62-210.200, F.A.C., Definitions-Potential to Emit (PTE), Major Source of Air Pollution, and Synthetic Non-Title V Source]

FW11. Modifications No emissions unit or facility shall be constructed or modified without obtaining the appropriate air construction permit. Such permit must be obtained prior to the beginning of construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

FW12. Circumvention No person shall circumvent any air pollution control device or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

FW13. Excess Emissions (EU Nos. 017 & 018):

a) Excess emissions resulting from malfunction of these emissions units shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized, but in no case exceed 15 minutes for startup, 15 minutes for shutdown, and 15 minutes for malfunction, in any 24 hour period. [Rules 62-210.700(1) & (5), F.A.C. and PSD-FL-291]

b) Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during start-up, shutdown, or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

FW14. When the Environmental Protection Commission of Hillsborough County, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the facility to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions units and to provide a report on the results of said tests to the Environmental Protection Commission of Hillsborough County. [Rule 62-297.310(7)(b), F.A.C.]

FW15. Duration of Recordkeeping Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to

complete the application for this permit. These materials shall be retained at least five years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
[Rules 62-4.160(14) and 62-213.440(1)(b)2.b., F.A.C.]

FW16. Test Reports The owner or operator of an emission unit for which a compliance test is required shall file a report with the Environmental Protection Commission of Hillsborough County (EPCHC) on the results of each compliance test as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Environmental Protection Commission of Hillsborough County to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

FW17. Excess Emissions Report If excess emissions occur, the owner or operator shall notify the Environmental Protection Commission of Hillsborough County within one working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Environmental Protection Commission of Hillsborough County may request a written summary report of the incident. [Rule 62-4.130, F.A.C.]

FW18. Excess Emissions Report - Malfunctions In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Environmental Protection Commission of Hillsborough County in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report if requested by the Department. [Rule 62-210.700(6), F.A.C.]

FW19. When appropriate, any recording, monitoring or reporting requirements that are time-specific shall be in accordance with the effective date of this permit, which defines day one. [Rule 62-213.440, F.A.C.]

FW20. Any reports, data, notifications, certifications, and requests required to be sent to the Environmental Protection Commission of Hillsborough County should be sent to:

Environmental Protection Commission of Hillsborough County
Air Management Division
3629 Queen Palm Drive
Tampa, FL 33619
Telephone: (813) 627-2600; Fax: (813) 627-2660

FW21. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303-8960
Telephone: 404/562-9155; Fax: 404/562-9163

FW22. The use of property, facilities, equipment, processes, products, or compounds, or the commission of paint overspraying or any other act, that causes or materially contributes to a public nuisance is prohibited.
[Hillsborough County Environmental Protection Act, Section 16, Chapter 84-446, Laws of Florida, as Amended.]

FW23. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information. [Rule 62-213.420(4), F.A.C.]

FW24. If the permittee wishes to transfer this permit to another owner, an "Application for Transfer of Permit" (DEP Form 62-210.900(7)) shall be submitted, in duplicate, to the Environmental Protection Commission of Hillsborough County within 30 days after the sale or legal transfer of the permitted facility.
[Rule 62-4.120, F.A.C.]

Subsection A. Emissions Units 001, 002, 003, 004

The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
-001	Wastewater Treatment Plant Sludge Dryer Train No. 2
-002	Wastewater Treatment Plant Sludge Dryer Train No. 3
-003	Building Fugitives and Odor Control System No. 1
-004	Building Fugitives and Odor Control System No. 2

Two identical sludge drying trains (No. 2 and No. 3) each consists of a wet storage bin, a pug mill, a gas fired rotary dryer, a separator, a crusher, sizing screens, a recycle bin, and the associated conveyor systems.

Emissions of particulate matter, volatile organic compounds and odorous compounds from each train are controlled by a venturi scrubber in series with a second cyclonic separator and a Hunting Energy Systems, Inc., Model No. 105 thermal oxidizer. Each train exhaust is ducted to a separate and identical emissions control system. Each incinerator has a maximum heat input rate of 3.78 MMBtu/hr., and is fired solely on natural gas. The dryer exhaust system includes an incinerator bypass outlet and a crossover duct, which allows one train to operate using the other train's incinerator unit. Fugitive emissions of odorous compounds are controlled by the complete enclosure of the sludge drying trains and the use of two (2) Quad Chemtact Mist Scrubbing Systems. The scrubbing liquor is a mixture of sodium hypochlorite and water. Typically only one odor control unit is in operation at any given time, but both may be in operation simultaneously.

In the heat recovery mode, Sludge Dryer Train No. 2 utilizes the exhaust gas from Engine No. 2 and Sludge Dryer Train No. 3 utilizes the exhaust gas from Engine No. 1. Additional heat can be added from each train's combustion chamber to handle the varying moisture content of the sludge.

{Permitting note(s): Emissions Units 001 and 002 are subject to 40 CFR 61, Subpart E - National Emission Standard for Mercury and Rule 62-296.712, F.A.C. - Miscellaneous Manufacturing Process Operations (RACT Particulate Matter).}

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum allowable processing rates are as follows:

EU No.	MMBtu/hr Heat Input	Fuel Type	Maximum Wet Sludge Input (tons/month)[1]	Minimum VOC Destruction Efficiency (%)	Minimum Afterburner Chamber Temperature(^oF)[2]
-001	20	Natural Gas	1,104	90	1299
-002	20	Natural Gas	1,104	90	1298

[1] Determined on a dry weight basis.

[2] Based on the 3-hour average during the latest successful emissions compliance test. Compliance is demonstrated based on a 3-hour average temperature.

[Rules 62-4.160(2), 62-4.070(3), 62-210.200(PTE), and Air Construction Permit AC29-246231]

A.2. Methods of Operation.

a. *Normal mode:* Heat for the sludge drying operation is provided by natural gas burned in the dryer(s).

b. *Heat Recovery mode:* Heat for the sludge drying operation is provided by waste heat generated from Engine No. 1 or Engine No. 2. The engines may provide all or a portion of the heat required to run the dryers.

[Rule 62-213.410, F.A.C., Rule 62-4.160(2), F.A.C.]

A.3. Hours of Operation. These emissions units may operate continuously (8,760 hours/year) under either normal or heat recovery mode of operation or any combination thereof.
[Rule 62-4.160(2), F.A.C. and Rule 62-210.200 (PTE), F.A.C.]

A.4. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

Emission Limitations and Standards

Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.5. Visible Emissions. Visible emissions shall not exceed 5% opacity from each drying train. [Construction Permit AC29-246231, Rule 62-296.712(2), F.A.C. and Renewal Application received November 12, 2010]

A.6. PM Emissions. Particulate matter emissions shall not exceed 5.15 lbs/hr and 22.6 tons in any twelve (12) consecutive month period from each drying train based on a design flow rate of 20,028 DSCFM.
[Construction Permit AC29-246231, Rules 62-296.700(4)(b)(1) and 62-296.712(2), F.A.C., and Renewal Application received November 12, 2010]

A.7. VOC Emissions. Volatile Organic Compound emissions shall not exceed 3.54 lbs/hr and 15.5 tons in any twelve (12) consecutive month period from each drying train. [Construction Permit AC29-246231, Permit No. 0570373-003-AV and Renewal Application received November 12, 2010]

A.8. Mercury Emissions. Total emissions of mercury from the sludge drying facility shall not exceed 3,200 grams (7.1 lb) per 24-hour period and 1.3 tons in any twelve (12) consecutive month period.
[40 CFR 61.52(b)]

A.9. Circumvention. The permittee shall not circumvent the emission limitation of Specific Condition A.6. by increasing the volume of gas in any exhaust or group of exhausts for the purpose of reducing the stack gas concentration. This includes allowing dilution air to enter the system through leaks, open vents, or similar means. [Rule 62-296.700(5), F.A.C.]

Excess Emissions

A.10. Excess Emissions Allowed. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

A.11. Excess Emissions Allowed. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

A.12. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.13. CAM Plan. Emissions units 001 and 002 are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C. [40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

Test Methods and Procedures

Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.14. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5	Determination of Particulate Matter Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
25A	Determination of Total Gaseous Organic Concentration using a Flame Ionization Analyzer
101A	Determination of particulate and gaseous mercury emissions
105	Determination of mercury in wastewater treatment plant sewage sludges

The above methods are described in 40 CFR 60, Appendix A or 40 CFR 61, Appendix B and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-296.712(3), 62-297.401 and 62-4.070(3), F.A.C., and Construction Permit AC29-246231]

A.15. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

A.16. Compliance Tests Required. The permittee shall have formal compliance tests conducted each calendar year on both sludge dryer trains for opacity in either the normal or heat recovery mode of operation. Every five (5) years, the permittee shall have formal compliance tests conducted on both sludge dryer trains for particulate matter (PM), volatile organic compounds (VOC), and mercury in either the normal or heat recovery mode of operation. However, if the results of a mercury test, as specified in Specific Condition A.17., indicate that either (or both) drying train's mercury emissions exceed 1.6 kg (3.5 lb) per 24-hour period, then the permittee shall monitor mercury emissions from that corresponding train (or both, if both exceeded the 3.5 lb/24-hr threshold) at intervals of at least once per year by use of the methods stated above. [Rule 62-297.310(7)(a), F.A.C. and 40 CFR 61.55(a)]

A.17. Mercury Compliance Test Requirements. For mercury, compliance testing shall be performed using EPA Methods 101A (in accordance to 40 CFR 61.53) or 105 contained in 40 CFR 61, Appendix B, and shall satisfy the following requirements:

(a) The Environmental Protection Commission of Hillsborough County shall be notified at least 30 days prior to a sludge sampling test.

(b) Sludge shall be sampled according to paragraph (b)(1) of this specific condition, sludge charging rate for the plant shall be determined according to paragraph (b)(2) of this specific condition, and the sludge analysis shall be performed according to paragraph (b)(3) of this specific condition.

  (1) The sludge shall be sampled according to EPA Method 105 - Determination of Mercury in Wastewater Treatment Plant Sewage Sludges. A total of three composite samples shall be obtained within an operating period of 24 hours. When the 24-hour operating period is not continuous, the total sampling period shall not exceed 72 hours after the first grab sample is obtained. Samples shall not be exposed to any condition that may result in mercury contamination or loss.

(2) The maximum 24-hour period sludge drying rate shall be determined by use of a flow rate measurement device that can measure the mass rate of sludge charged to the dryer with an accuracy of ± 5 percent over its operating range. Other methods of measuring sludge mass charging rates may be used if they have received prior approval by the Environmental Protection Commission of Hillsborough County.

(3) The sampling, handling, preparation, and analysis of sludge samples shall be accomplished according to EPA Method 105 in 40 CFR 61, Appendix B.

(c) The mercury emissions shall be determined by use of the following equation.

$$E_{Hg} = \frac{M \text{ x } Q \text{ x } Fsm(avg)}{1000}$$

where:
E_{Hg} = mercury emissions, grams/day
M = mercury conc. of sludge on a dry basis, micrograms/gram sludge
Q = sludge feed rate, kilograms/day
Fsm = weight fraction of solids in the collected sludge after mixing

(d) No changes in the operation of a plant shall be made after a sludge test has been conducted which would potentially increase emissions above the level determined by the most recent sludge test, until the new emission level has been estimated by calculation and the results reported to the Environmental Protection Commission of Hillsborough County.

(e) All sludge samples shall be analyzed for mercury content within 30 days after the sludge sample is collected. Each determination shall be reported to the Environmental Protection Commission of Hillsborough County by a registered letter dispatched within 15 calendar days following the date such determination is completed.

(f) Records of sludge sampling, charging rate determination and other data needed to determine mercury content of wastewater treatment plant sludges shall be retained at the source and made available, for inspection by the Environmental Protection Commission of Hillsborough County, for a minimum of five (5) years.

(g) The minimum requirements for source sampling and reporting shall be in accordance with Rule 62-297, F.A.C., and 40 CFR 60, Appendix A.

[40 CFR 61.53 and 61.54, Construction Permit AC29-246231, and Rule 62-213.440(1)(b)2.b..F.A.C.]

A.18. Operating Rate During Testing. Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 90-100% of 3,067 lbs/hour of sludge input per train (dry weight basis), based on the permitted limit of 1,104 dry tons per month. If it is impracticable to test at capacity, then the source may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Environmental Protection Commission of Hillsborough County. Failure to submit the input rates and actual operating conditions, such as the sludge input rate (dry weight basis), heat input rate, thermal oxidizer temperature, scrubber liquid flow rate, and scrubber pressure drop, may invalidate the test. [Construction Permit AC29-246231 and Rule 62-297.310(2) and (8)(c), F.A.C.]

A.19. The required minimum period of observation for each EPA Method 9 compliance test shall be thirty (30) minutes. The opacity test observation period shall include the period during which the emissions unit is operating at capacity as defined in specific condition A.11. Exceptions to these requirements are as follows:

(a) The minimum observation period for opacity tests conducted by the Environmental Protection Commission of Hillsborough County to verify the day-to-day continuing compliance of a unit or activity shall be twelve minutes.

[Rule 62-297.310(4)(a), F.A.C.]

Monitoring, Recordkeeping, and Reporting Requirements

A.20. The following Operation and Maintenance (O&M) Plan, including all the referenced design parameters, monitoring requirements and recordkeeping requirements, is an enforceable condition of this permit. In order to demonstrate compliance with Specific Condition Nos. A.5, A.6, A.7., and A.8. the permittee shall maintain records of operations as specified in the following O&M Plan**:**

Operation and Maintenance Plan for Particulate Control:

- (a) Process Parameters:
  - (1) Cyclone Separators (two (2))
    - (i) Manufacturer: Emtrol Corporation
    - (ii) Model Name and Number: 2-52M160
    - (iii) Design Flow Rate: 28,724 ACFM @ 178° F
  - (2) Venturi Scrubber/Cyclonic Separator (two (2))
    - (i) Manufacturer: Emtrol Corporation
    - (ii) Model Name and Number: 42096 W-20
    - (iii) Design Flow Rate: 28,724 ACFM @ 178° F. - Air, 288 gallons/min. - H_2O
    - (iv) Minimum Flow Rate: 250 gallons/min - H_2O
    - (v) Minimum Pressure Drop: 6.0 inches H_2O
  - (3) Afterburner (two (2))
    - (i) Manufacturer: Huntington Energy Systems, Inc.
    - (ii) Model Name and Number: 105
    - (iii) Design Flow Rate: 35,124 ACFM @ 261° F.
    - (iv) Overall Efficiency Rating at Design Capacity: 99.64% PM, 90% VOC
    - (v) Stack Height Above Ground: 75 ft.
    - (vi) Exit Diameter: 3.1 ft.
    - (vii) Exit Velocity: 67 f.p.s.
    - (viii) Water Vapor Content: 15.25%
    - (ix) Process Controlled by Collection System: Train Nos. 2 and 3
    - (x) Material Handling Rate: 1104 tons of sludge input per train per month (dry weight basis) or 3,067 lbs./hour.
    - (xi) Operation Schedule: 24 hrs./day; 7 days/wk.; 52 wks./yr.
  - (4) Odor Control System (2 units)
    - (i) Manufacturer: Quad Environmental Technologies
    - (ii) Model Name and Number: Quad Chemtact Mist Scrubbing System
    - (iii) Design Flow Rate: 49,000 ACFM - Air, 2.25 gpm - Scrubbing Solution (H_2O + NaOCl)
    - (iv) Minimum Flow Rate: 0.3 gpm - Scrubbing Solution (10% NaOCl + H_2O)
    - (v) Minimum System Air Pressure: 70 psi
    - (vi) Stack Height Above Ground: 38 ft.
    - (vii) Exit Diameter: 5 ft.
    - (viii) Exit Velocity: 41.59 f.p.s.
    - (ix) Process Controlled by Collection System: Train Nos. 2 and 3
    - (x) Operation Schedule: 24 hrs./day; 7 days/wk.; 52 wks./yr.

- (b) The following observations, procedures, checks and recordkeeping requirements are to be completed at the frequency specified for monitoring and control of source discharge:
  - (1) Daily
    - (i) Record natural gas consumption for each dryer in MMBTU/day

(ii) Record belt scale totalizer readings.
(iii) Observe Wet Bin level.
(iv) Check Recycle Bin level.
(v) Check cyclone drop-out for plugging.
(vi) [Reserved]
(vii) Record venturi scrubber pressure drop and water flow rate.
(viii) Record ID fan DP.
(ix) Check afterburner operation including burner status. Record reaction chamber, inlet, and outlet temperatures. To demonstrate requirements established in the CAM Plan, records of instantaneous and 1-hour average temperatures of the afterburner chamber shall be maintained.
(x) Perform and record the results of an instantaneous visual emissions determination on each afterburner.
(xi) Observe building odor control operation - check chemical feed and filter pressure, and record scrubbing solution flow rate and system air pressure.
(xii) Perform general cleaning around conveyors and belt scales.
(xiii) Maintain records of dryer feed rates and total natural gas usage of sludge drying system including afterburner.

(2) Weekly
(i) Inspect afterburner exhaust fan and reactor switch valves for proper operation.
(ii) Observe operation and condition of settling chamber, cyclone, venturi scrubber, and ID fan.
(iii) Check odor control compressors for water and oil level.
(iv) Perform acid cleaning to nozzles of building odor control system.

(3) Monthly
(i) Record monthly dry sludge production per train and maintain 12-month rolling average.
(ii) Determine and record mercury concentration in the wet sludge using EPA Method 7471 or the latest EPA approved method. Calculate and record the estimated mercury emissions for each month and maintain a 12-month rolling average.
(iii) Inspect and clean ID fans for build-up of debris if needed.
(iv) Manually inspect and clean building odor control nozzles.
(v) Lubricate afterburner switch valve camshaft.

(4) Semiannually
(i) Check oil in bearings of ID fan and afterburner fan.
(ii) Inspect afterburner fan for build-up of debris and clean.
(iii) Perform mechanical check on all gas piping for leaks.
(iv) Perform mechanical inspection and lubrication of vane axial fan of building odor control system.

(5) Annually
(i) Lubricate afterburner fan bearings and perform electrical checks for proper operation.
(ii) Perform electrical checks to building exhaust fan and lubricate.
(iii) Inspect afterburner insulation for refractory lining damage.

(c) Records: Records of inspections, maintenance, and performance parameters shall be retained for a minimum of five years and shall be made available to the Environmental Protection Commission of Hillsborough County, state or federal air pollution agency upon request.

(d) Deviations: If at any time any of the operating restrictions of (a)(2)(iv), (a)(2)(v), (a)(4)(iv), or (a)(4)(v) of this specific condition is not met, immediate corrective action shall be taken and a deviation plan shall be submitted within 30 days to the Environmental Protection Commission of Hillsborough County. A single observation of visible emissions pursuant to (b)(1)(x) shall also trigger the need for corrective actions and the submission of a deviation plan.

[Construction Permit AC29-246231; and Rules 62-213.440(1)(b)2.b., 62-296.700(4) & (6) and 62-4.070(3), F.A.C.]

A.21. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

Subsection B. Emissions Units 005, 006, 007, 008, 009, 010

The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
-005	Sludge Silo No. 2
-006	Sludge Silo No. 3
-007	Sludge Silo No. 4
-008	Sludge Silo No. 5
-009	Truck Loading Station No. 1
-010	Truck Loading Station No. 2

Four storage silos store dry pelletized sludge (natural fertilizer) generated from the two sludge dryer trains. Two truck loading stations load the product from the silos into trucks. Particulate emissions generated during silo loading are controlled by four dust collectors, one on each silo. Emissions generated by the truck loading operations are controlled by two dust collectors.

{Permitting note(s): These emissions units are subject to Rule 62-296.711, F.A.C. - Materials Handling, Sizing, Screening, Crushing and Grinding Operations (RACT Particulate Matter).}

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum allowable sludge handling rate is as follows:

EU Nos.	Tons Dry Sludge/12-Consecutive Month Period
-005 thru -010	36,576

[Rules 62-4.160(2), 62-4.070(3), 62-204.800, 62-210.200(PTE), and Renewal Application received November 12, 2010]

B.2. Hours of Operation. These emissions units may operate continuously (8,760 hours/year). [Rule 62-210.200(PTE) and 62-4.070(3), F.A.C., and Renewal Application received November 12, 2010]

B.3. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

Emission Limitations and Standards

Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.4. Visible Emissions. Visible emissions shall not exceed 5% opacity. [Rules 62-296.711 and 62-297.620(4), F.A.C., Construction Permit AC29-203780, and Renewal Application received November 12, 2010]

B.5. PM Emissions. Particulate matter emissions shall not exceed 0.03 gr/dscf, 0.26 pounds/hr, and 1.13 tons/twelve (12) consecutive month period for each emission unit in this subsection. [Rules 62-296.711 and 62-297.620(4), F.A.C., Construction Permit AC29-203780, and Renewal Application received November 12, 2010]

Excess Emissions

B.6. Excess Emissions Allowed. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

B.7. Excess Emissions Allowed. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

B.8. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Test Methods and Procedures

Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.9. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5	Determination of Particulate Matter Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-297.401, F.A.C. and Construction Permit AC29-203780]

B.10. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

B.11. Annual Compliance Tests Required. During each federal fiscal year (October 1st to September 30th), Emission Units 005 through 010 shall be tested to demonstrate compliance with the emissions standards for opacity. A visible emissions test indicating no visible emissions (5 percent opacity) may be submitted in lieu of a particulate stack test for these emissions units; however, failure to demonstrate compliance with the 5% opacity standard may require formal PM stack testing using EPA Method 5 to ensure compliance with Specific Condition B.5. [Rules 62-297.310(7)(a)4., 62-297.620(4), and 62-296.711, F.A.C.]

B.12. Operating Rate During Testing. Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 90-100% of the maximum loading rate of 24,000 lbs/hr for each silo and the maximum truck loading rate 42,000 lbs/hr for each truck loading station. The loading rates are considered maximum average rates, so some fluctuation in instantaneous loading may occur. If it is impracticable to test at capacity, then the source may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Environmental Protection Commission of Hillsborough County. Failure to submit the input rates and actual operating conditions may invalidate the test. [Construction Permit AC29-203780 and Rule 62-297.310(2), F.A.C.]

B.13. The required minimum period of observation for an EPA Method 9 compliance test shall be thirty (30) minutes. Observations should be made at the point of highest opacity from the operation. The opacity test observation period shall include the period during which the emissions unit is operating at capacity as defined in specific condition B.12. Exceptions to these requirements are as follows:

(a) The minimum observation period for opacity tests conducted by the Environmental Protection Commission of Hillsborough County to verify the day-to-day continuing compliance of a unit or activity shall be twelve minutes. [Rules 62-297.310(4)(a) and 62-4.070(3), F.A.C.]

Monitoring, Recordkeeping, and Reporting Requirements

B.14. Operation and Maintenance Plan. The following Operation and Maintenance (O&M) Plan, including all the referenced design parameters, monitoring requirements, and recordkeeping requirements, is an enforceable condition of this permit. In order to demonstrate compliance with Specific Condition Nos. B.4. and B.5., the permittee shall maintain records of operations as specified in the following O&M Plan**:**

Operation and Maintenance Plan for Particulate Control:

- (a) Equipment Specifications:
  - (1) Dust Collector Bin Vent (4) - Silo Nos. 2, 3, 4, and 5
    - (i) Manufacturer: American Air Filter
    - (ii) Model: Fabri-Pulse, Design M, Model 2, Size 6-42-150 dust collector
    - (iii) Maximum pressure Drop: 6.0 inches H_2O
  - (2) Truck Loading Dust Collector (2) - Truck Loading Station Nos. 1 and 2
    - (i) Manufacturer: American Air Filter
    - (ii) Model: Fabri-Pulse, Design M, Model 2, Size 6-42-150 dust collector
    - (iii) Maximum Pressure Drop: 6.0 inches H_2O
  - (3) Rotary Valves (4) - Silos Nos. 2, 3, 4, and 5
    - (i) Manufacturer: MAC
    - (ii) Model: MD7 w/VFD controller
    - (iii) Material Handling Rate: 42,000 lbs./hr. maximum
    - (iv) Operation Schedule: 8760 hrs./yr.
- (b) The following observations, procedures, checks and recordkeeping requirements are to be completed at the frequency specified for monitoring and control of source discharge:

Dust Collector Bin Vent

- (1) Daily
  - (i) Observe bin vent operating status for silo in service.
  - (ii) Perform and record the results of an instantaneous visual emissions determination on each silo in service.
  - (iii) Note silo product levels.
  - (iv) Note silo product temperatures.
- (2) Annually
  - (i) Perform inspection of filters - clean/replace if necessary.
  - (ii) Inspect filters for leakage.
  - (iii) Lubricate fan motor and perform electrical check.

Truck Loading Dust Collector

- (3) Daily
  - (i) Record dust collector differential pressure and observe operation for leaks.
  - (ii) Perform and record the results of an instantaneous visual emissions determination on each dust collector.
- (4) Monthly
  - (i) Record total monthly dry sludge loaded and maintain 12-month rolling average.
  - (ii) Inspect filters - clean/replace as necessary.
  - (iii) Inspect loading spout and apron for wear.
  - (iv) Check air and water supply of dust removal system.
- (5) Annually
  - (i) Perform electrical inspection and motor lubrication

For Rotary Valves on Silos Nos. 2, 3, 4, 5

(6) Daily
  (i) Record the frequency of the Rotary Valve Variable Frequency Drive.

(7) Annually
  (i) Visually inspect rotary valve for product buildup and damage.
  (ii) Perform electrical and mechanical inspections and maintenance per manufacturer's specifications.
  (iii) Verify product load rate.

(c) Records: Records of inspections, maintenance, and performance parameters shall be retained for a minimum of five years and shall be made available to the Environmental Protection Commission of Hillsborough County upon request.

(d) Deviations: If at any time any of the operating restriction of (a)(2)(iii) of this specific condition is not met, immediate corrective action shall be taken and a deviation plan shall be submitted within 30 days to the Environmental Protection Commission of Hillsborough County. A single observation of visible emissions pursuant to (b)(1)(ii) or (b)(3)(iii) shall also trigger the need for corrective actions and the submission of a deviation plan.

[Rules 62-296.700(4) & (6) and 62-213.440(1)(b), F.A.C.]

Subsection C. The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
-011	Sludge Silo No. 6
-016	Silo No.6 Truck Loading Spout

Silo No.6 receives dry pelletized sludge from any of the four storage silos, where the product is then loaded out into trucks through its dedicated loading spout. Particulate emissions generated during silo filling and truck loading operation are controlled by a single dust collector.

{Permitting note(s): These emissions units are subject to Rule 62-296.711, F.A.C. - Materials Handling, Sizing, Screening, Crushing and Grinding Operations (RACT Particulate Matter).}

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. The maximum allowable sludge handling rate is as follows:

EU Nos.	Tons Dry Sludge/12-Consecutive Month Period
-011 and -016	10,000

[Rules 62-4.160(2), 62-4.070(3), 62-204.800, 62-210.200(PTE), and Renewal Application received November 12, 2010]

C.2. Hours of Operation. These emissions units may operate continuously (8,760 hours/year). [Rule 62-210.200(PTE) and 62-4.070(3), F.A.C., and Renewal Application received November 12, 2010]

C.3. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

Emission Limitations and Standards

Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.4. Visible Emissions. Visible emissions shall not exceed 5% opacity. [Rules 62-296.711 and 62-297.620(4), F.A.C., Construction Permit 0570373-002-AC, and Renewal Application received November 12, 2010]

C.5. PM Emissions. Particulate matter emissions shall not exceed 0.03 gr/dscf, 0.81 pounds/hr, and 3.6 tons/twelve (12) consecutive month period for each emission unit in this subsection. [Rules 62-296.711 and 62-297.620(4), F.A.C., Construction Permit 0570373-002-AC, and Renewal Application received November 12, 2010]

Excess Emissions

C.6. Excess Emissions Allowed. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

C.7. Excess Emissions Allowed. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

C.8. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Test Methods and Procedures

Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.9. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5	Determination of Particulate Matter Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-297.401, F.A.C. and Construction Permit 0570373-002-AC]

C.10. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

C.11. Annual Compliance Tests Required. During each federal fiscal year (October 1st to September 30th), Emission Units 011 and 016 shall be tested to demonstrate compliance with the emissions standards for opacity. A visible emissions test indicating no visible emissions (5 percent opacity) may be submitted in lieu of a particulate stack test for these emissions units; however, failure to demonstrate compliance with the 5% opacity standard may require formal PM stack testing using EPA Method 5 to ensure compliance with Specific Condition C.5. [Rules 62-297.310(7)(a)4., 62-297.620(4), and 62-296.711, F.A.C.]

C.12. Operating Rate During Testing. Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 90-100% of the rated capacity of 20,000 lbs/hr for Silo No. 6 and the maximum truck loading rate of 40,000 lbs/hr for the loading spout. The loading rates are considered maximum average rates, so some fluctuation in instantaneous loading may occur. If it is impracticable to test at capacity, then the source may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Environmental Protection Commission of Hillsborough County. Failure to submit the input rates and actual operating conditions may invalidate the test. [Construction Permit 0570373-002-AC and Rule 62-297.310(2), F.A.C.]

C.13. The required minimum period of observation for an EPA Method 9 compliance test shall be thirty (30) minutes. Observations should be made at the point of highest opacity from the operation. The opacity test observation period shall include the period during which the emissions unit is operating at capacity as defined in Specific Condition C.12. Exceptions to these requirements are as follows:

(a) The minimum observation period for opacity tests conducted by the Environmental Protection Commission of Hillsborough County to verify the day-to-day continuing compliance of a unit or activity shall be twelve minutes. [Rules 62-297.310(4)(a) and 62-4.070(3), F.A.C.]

Monitoring, Recordkeeping, and Reporting Requirements

C.14. Operation and Maintenance Plan. The following Operation and Maintenance (O&M) Plan, including all the referenced design parameters, monitoring requirements, and recordkeeping requirements, is an enforceable condition of this permit. In order to demonstrate compliance with Specific Condition Nos. C.4. and C.5., the permittee shall maintain records of operations as specified in the following O&M Plan**:**

Operation and Maintenance Plan for Particulate Control

(a) Source Designator:
  (1) Truck Loading Retractable Spout
    (i) Manufacturer: Pebco
    (ii) Model: CLS-22
  (2) Baghouse Air Filter
    (i) Manufacturer: Kice
    (ii) Model: VS 36-10 Venturi-Jet
    (iii) Design Flow: 3,150 dscfm
    (iv) Efficiency Rating: 99%
    (v) Maximum Pressure Drop: 8 inches H_2O
    (vi) Air to Cloth Ratio: 7.5:1
    (vii) Bag Weave: 420 sq. ft. @ 12 oz./sq. yd.
    (viii) Bag Material: Polyester Felt
    (ix) Bag Cleaning Conditions: Pulse Jet every 180 seconds
    (x) Gas Flow Rate: 3150 scfm
    (xi) Gas Temperature: Ambient
    (xii) Stack Height Aboveground: 20 ft.
    (xiii) Exit dimensions: 12 in. x 12 in.
    (xiv) Exit Velocity: 3150 ft/min
    (xv) Water Vapor Content: Ambient
    (xvi) Process Controlled by Baghouse: Bin Loading
    (xvii) Material Handling Rate: 10 tons/hour silo loading; 40,000 lbs/hour truck loading
    (xviii) Operation Schedule: 8,760 hrs/yr

(b) The following observations, procedures, and checks shall be performed at the frequency specified.
  For Retractable Spout
  (1) Daily
    (i) Observe operation of spout during truck loading for proper operation.
  (2) Monthly
    (i) Record the monthly dry sludge processed and maintain 12-month rolling average.
  (2) Quarterly
    (i) Inspect lifting cable assembly.
    (ii) Inspect loading spout and apron for wear.
  (3) Annually
    (i) Perform electrical and mechanical inspections.
  For Baghouse Air Filter
  (4) Daily
    (i) Record Baghouse Air Filter differential pressure.
    (ii) Record reverse air pressure.
    (iii) Observe system, listening for leaks and proper operation.
    (iv) Perform and record the results of an instantaneous visual emissions determination.
  (5) Weekly
    (i) Check bag cleaning sequence for proper operation.
    (ii) Check differential pressure indicating equipment for plugged lines.
  (6) Quarterly
    (i) Inspect filters--clean and replace as necessary.

        - (ii) Inspect airlock for leaks and vibration.
        - (iii) Inspect fan for corrosion and material build-up.
    - (7) Annually
        - (i) Lubricate bearings on blower and air lock.
        - (ii) Perform electrical and mechanical inspections and maintenance per manufacturer's specifications.
- (c) <u>Records:</u> Records of inspections, maintenance, and performance parameters shall be retained for a minimum of five years and shall be made available to the Environmental Protection Commission of Hillsborough County upon request.
- (d) <u>Deviations:</u> If at any time any of the operating restriction of (a)(2)(v) of this specific condition is not met, immediate corrective action shall be taken and a deviation plan shall be submitted within 30 days to the Environmental Protection Commission of Hillsborough County. A single observation of visible emissions pursuant to (b)(4)(iv) shall also trigger the need for corrective actions and the submission of a deviation plan.

[Rules 62-296.700(4) & (6) and 62-213.440(1)(b), F.A.C.]

Subsection D. Emissions Unit 012

The specific conditions in this section apply to the following emissions unit(s):

EU No.	Brief Description
-012	Four Emergency Diesel Generators

Four stationary diesel-fired emergency generators supply emergency power to the facility. The emergency generator engines are four Caterpillar 3516 DITA engines, 4 stroke compression ignition, rated at 2,847 bhp, and are fired on No. 2 diesel fuel at a maximum rate of 137.5 gallons/hr. Each engine is coupled to a 2 MW generator. These engines are subject to 40 CFR 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE).

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum allowable heat input rate is as follows:

EU No.	Gallons/12-Consecutive Month Period	Fuel Type	Sulfur Content
-012	115,000	No. 2 Diesel Fuel	0.05 wt%

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), and Permit No(s). 0570373-006-AC.]

D.2. Hours of Operation. This emission unit may operate as needed to off-set power shortages during the year without restrictions on hours, but must abide by the maximum fuel usage from Specific Condition D.1. [Rule 62-210.200(PTE), F.A.C., Permit No. 0570373-006-AC]

D.3. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

Emission Limitations and Standards

Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.4. Visible Emissions. Visible emissions from the generators shall not exceed 20% opacity. [Construction Permit 0570373-006-AC and Rule 62-296.320(4)(b)1., F.A.C.]

D.5. PM Emissions. Particulate matter emissions shall not exceed 0.79 tons in any twelve (12) consecutive month period in order to exempt this emission unit from PM-RACT. [Rule 62-210.200(PTE) and 62-296.700, F.A.C., and Construction Permit 0570373-006-AC]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

D.6. Excess Emissions Allowed. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

D.7. Excess Emissions Allowed. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

D.8. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Test Methods and Procedures

Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.9. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-297.401, F.A.C., and Construction Permit No. 0570373-006-AC]

D.10. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

D.11. Annual Compliance Tests Required. During each federal fiscal year (October 1st to September 30th), each generator engine shall be tested to demonstrate compliance with the emissions standards for opacity in accordance with EPA Method 9. [Rules 62-297.310(7)(a)4., F.A.C., and Permit No. 0570373-006-AC]

D.12. Operating Rate During Testing. Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 90-100% of the rated capacity of 137.5 gallons per hour per generator. If it is impracticable to test at capacity, then the source may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Environmental Protection Commission of Hillsborough County. Failure to submit the input rates, actual operating conditions and fuel oil certification from Specific Condition D.15. may invalidate the test. [Construction Permit 0570373-006-AC and Rule 62-297.310(2), F.A.C.]

D.13. The required minimum period of observation for a EPA Method 9 compliance test shall be thirty (30) minutes. The opacity test observation period shall include the period during which the emissions unit is operating at capacity as defined in Specific Condition D.12. Exceptions to these requirements are as follows:

(a) The minimum observation period for opacity tests conducted by the Environmental Protection Commission of Hillsborough County to verify the day-to-day continuing compliance of a unit or activity shall be twelve minutes.

[Rule 62-297.310(4)(a), F.A.C.]

Monitoring, Recordkeeping, and Reporting Requirements

D.14. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

D.15. Fuel Oil Analysis. A certificate of fuel oil analysis from either the fuel vendor or from a sample taken from each shipment received shall be maintained. The sample shall be analyzed according to ASTM Method D-396-76. [Construction Permit 0570373-006-AC]

D.16. The permittee shall perform and maintain records of the following maintenance and inspection requirements for each emergency generator:

(a) Semiannually:
  (1) Replace engine intake air filter.
  (2) Replace engine cartridge fuel filter.

(3) Replace spent engine primary fuel filter.
(4) Alternate fuel transfer pump strainer and fuel filter.
(5) Clean spent fuel strainer and housing.
(6) Replace spent fuel filter element.
(7) Conduct load test and sample lube oil after engine reaches operating temperature.

(b) Annually or Every 250 hours of operation:
(1) Replace engine lube oil filter.
(2) Drain used lube oil and replace with fresh oil.
(3) Drain and flush engine coolant and refill using chemical treatment.
(4) Inspect all hoses and belts and adjust or replace as necessary.
(5) Drain contaminants from fuel day tank bottom.
(6) Test all engine shut-down devices.
(7) Load test engine and generator.

Records shall be retained for a minimum of five years and shall be made available to the Environmental Protection Commission of Hillsborough County upon request.

[40 CFR 63.6603 and Rule 62-213.440(1)(b)1.b., F.A.C.]

D.17. The permittee shall maintain monthly and 12-month rolling totals of fuel usage. [Rule 62-213.440(1)(b)1.b., F.A.C.]

D.18. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements in Specific Condition D.16. on the schedule required, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable. [40 CFR 63.6603 and 63.6640]

D.19. The permittee shall keep the following records:

(a) (1) A copy of each notification and report that was submitted, including all documentation supporting any Initial Notification or Notification of Compliance Status, according to the requirement in §63.10(b)(2)(xiv).
(2) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment).
(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).
(4) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) Records of hours of operation of the engine that is recorded through a non-resettable hour meter. The permittee shall install a non-resettable hour meter on each engine if one is not already installed. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.[40 CFR 63.6655]

D.20. At all times the permittee shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with the manufacturer's emission-related operation and maintenance instructions and good air pollution control practices for

minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if the levels required have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.
[40 CFR 63.6605 and 63.6640]

Other Requirements

D.21. Federal 40 CFR 63 NESHAP Subpart ZZZZ Requirements – In addition to the Specific Conditions listed in this permit, the existing stationary engines, EU ID No. 012, are required to comply with all the applicable requirements of NESHAP 40 CFR 63 Subpart ZZZZ (National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE)), which is attached to this permit. The compliance date for EU 012 is May 3, 2013.
[40 CFR 63 Subpart ZZZZ, Rule 62-204.800, F.A.C., and Rule 62-4.070(3), F.A.C.]

Subsection E. Emissions Units 017 and 018

The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
-017	Engine No. 1 with nominal 2.9 MW generator: 4073 brake hp natural gas fired Waukesha Model 16V-AT27GL engine coupled to a nominal 2.9 MW electrical generator. Maximum heat input rate is 27.2 MMBtu/hr (HHV) based on a natural gas heating value of 1,025 Btu/cf.
-018	Engine No. 2 with nominal 2.9 MW generator: 4073 brake hp natural gas fired Waukesha Model 16V-AT27GL engine coupled to a nominal 2.9 MW electrical generator. Maximum heat input rate is 27.2 MMBtu/hr (HHV) based on a natural gas heating value of 1,025 Btu/cf.

The identification of these two generators was changed from Engines 7 and 8 to Engines 1 and 2 at the request of the permittee. In the heat recovery mode, Engine 2 only exhausts its gas to Sludge Dryer Train No. 2 and Engine 1 only exhausts its gas to Sludge Dryer Train No. 3.

[Note: These emissions units are subject to the requirements for Prevention of Significant Deterioration pursuant to Rule 62-212.400, F.A.C., for NO_x and of the state rules as indicated in this permit. Emissions of CO and VOC are limited to ensure that these emission units will not exceed the PSD significance level for these pollutants.]

Essential Potential to Emit (PTE) Parameters

E.1. Permitted Capacity. The maximum allowable heat input rate is as follows:

EU No.	MMBtu/hr Heat Input	Fuel Type
-017	27.2	Natural Gas
-018	27.2	Natural Gas

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), and Air Construction Permit No. 0570373-009-AC]

E.2. Methods of Operation.

a. *Normal mode*: Emissions from the engines are vented directly to the atmosphere through a stack.

b. *Heat Recovery mode*: Emissions from the engines are ducted to the sludge drying train(s) to provide supplemental heat input for the sludge drying process. Heat for the sludge drying operation is provided by waste heat generated from Engine No. 1 or Engine No. 2. The engines may provide all or a portion of the heat required to run the dryers. [Rule 62-213.410, F.A.C., Rule 62-4.160(2), F.A.C.]

E.3. Hours of Operation. Combined operation of these emissions units shall not exceed 13,000 hours/12 consecutive month period under either the direct venting of engine exhausts to the atmosphere or heat recovery mode of operation or any combination thereof. [Rule 62-210.200, F.A.C., Definitions-Potential to Emit (PTE), and limitation on PTE to avoid PSD for CO and VOC; Revised (07/01) with PSD-FL-291A]

E.4. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

Emission Limitations and Standards

Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.5. Visible Emissions. Visible emissions from each engine shall not exceed 20% opacity.
[Rule 62-296.320, F.A.C. and Construction Permit 0570373-010-AC]

E.6. NO_X Emissions. Nitrogen oxide emissions from each engine shall not exceed 14.0 lbs/hour, based on a 3-hour averaging time. NO_X emissions are to be reported as NO_2. [Rules 62-4.070(3) and 62-212.400, F.A.C., BACT (for NOx), and Construction Permit 0570373-010-AC]

E.7. CO Emissions. Carbon Monoxide emissions from each engine shall not exceed 14.9 lbs/hour, based on a 3-hour averaging time. [Rules 62-4.070(3) and 62-212.400, F.A.C., and Construction Permit 0570373-010-AC]

E.8. VOC Emissions. Volatile Organic Compound emissions from each engine shall not exceed 5.0 lbs/hour, based on a 3-hour averaging time [Rules 62-4.070(3) and 62-212.400, F.A.C., and Construction Permit 0570373-010-AC]

[Permitting Note: The mass emission limits correspond to the following emissions at full load in units of g/bhp-hr: VOC, 0.55, NOx, 1.56, CO, 1.66. This condition and the hours of operation limitation will effectively limit VOC, NOx, and CO emissions to 32.5, 91.0 and 96.8 tons per year, respectively.]

E.9. Emissions Reductions: By October 19, 2013, the permittee shall either:
(a) Limit the concentration of CO in the stationary RICE exhausts to 47 ppmvd at 15 percent O_2; or
(b) Reduce CO emissions by 93 percent or more.
[40 CFR 63.6603]

E.10. During periods of startup the permittee shall minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. [40 CFR 63.6625(h)]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

E.11. Excess Emissions Allowed. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

E.12. Excess Emissions Allowed. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

E.13. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Test Methods and Procedures

Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.14. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
7 or 7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography (optional)[1]
25 or 25A	Method for Determining Gaseous Organic Concentrations

[1] Method 18 may be used to determine the methane content which may be excluded from the total VOC measured using Method 25 or 25A.

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-4.070(3), 62-212.400, 62-297.340, and 62-297.401, F.A.C.]

E.15. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

E.16. Annual Compliance Tests Required. During each federal fiscal year (October 1st to September 30th), each engine shall be tested to demonstrate compliance with the emissions standards for NO_X, CO, and opacity. Compliance with the emission limits for NO_X and CO shall be demonstrated by compliance tests conducted annually on both emissions units in the heat recovery mode of operation. The testing location shall be the sample ports in the ducts between the engines and the sludge dryer trains. Compliance with the opacity limit shall be demonstrated annually by EPA Method 9 while the engines are being vented directly to the atmosphere. The required minimum period of observation for the EPA Method 9 compliance test shall be thirty (30) minutes. [Rule 62-297.310(4) and (7), F.A.C. and Permit No. 0570373-010-AC]

E.17. Compliance Tests Prior To Renewal. Compliance tests shall be performed on each engine for VOC once every 5 years in the heat recovery mode of operation. The test shall occur prior to obtaining a renewed operating permit to demonstrate compliance with the emission limit in Specific Condition E.8. [Rules 62-210.300(2)(a) and 62-297.310(7)(a), F.A.C.]

E.18. Operating Rate During Testing. Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 90-100% of the rated capacity of 27.2 MMBtu/hr per engine. If it is impracticable to test at capacity, then the source may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Environmental Protection Commission of Hillsborough County. Failure to submit the input rates, actual operating conditions may invalidate the test. [Construction Permit 0570373-010-AC and Rule 62-297.310(2), F.A.C.]

E.19. The required minimum period of observation for a EPA Method 9 compliance test shall be thirty (30) minutes. The opacity test observation period shall include the period during which the emissions unit is operating at capacity as defined in Specific Condition E.18. Exceptions to these requirements are as follows:

(a) The minimum observation period for opacity tests conducted by the Environmental Protection Commission of Hillsborough County to verify the day-to-day continuing compliance of a unit or activity shall be twelve minutes.

[Rule 62-297.310(4)(a), F.A.C.]

Monitoring, Recordkeeping, and Reporting Requirements

E.20. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

E.21. Monthly Records: The owner or operator shall equip each engine with a run hours meter and shall maintain monthly records of hours of operation, rolling 12-month total hours of operation, and fuel consumption for each emission unit no later than ten days after the end of each month.
[Rule 62-4.070(3), F.A.C.]

E.22. At all times the permittee shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with the manufacturer's emission-related operation and maintenance instructions and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if the levels required have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.
[40 CFR 63.6605(b)]

E.23. The permittee shall keep the following records:

(a) A copy of each notification and report that was submitted, including all documentation supporting any Initial Notification or Notification of Compliance Status, according to the requirement in §63.10(b)(2)(xiv).

(b) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment).

(c) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(d) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
[40 CFR 63.6655]

Other Requirements

E.24. Federal 40 CFR 63 NESHAP Subpart ZZZZ Requirements – In addition to the Specific Conditions listed in this permit, the existing stationary engines, EU ID No. 017 and 018, are required to comply with all the applicable requirements of NESHAP 40 CFR 63 Subpart ZZZZ (National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE)), which is attached to this permit. The compliance date for EU 017 and 018 is October 19, 2013. [40 CFR 63 Subpart ZZZZ, Rule 62-204.800, F.A.C., and Rule 62-4.070(3), F.A.C.]

Subsection F. Emissions Unit 019

The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
-019	Methanol Storage Tank

A methanol tank is used within the wastewater processing section of the facility as feedstock for the biological denitrification stage of the water treatment process. The fixed roof storage tank was constructed in 1978 with a volume of approximately 95,000 gallons. The tank is typically loaded on a daily to weekly basis by tanker truck or railcar. Methanol is considered a VOC and a HAP, and emissions are generated by evaporative losses (breathing and working losses) through the venting of displaced air through the "J" neck vent located on the roof of the tank. Emissions are also generated from evaporation of methanol in the denitrification stage and from the fugitive losses of handling methanol through the piping, valves, flanges etc. Potential emissions from the tank have been determined to be greater than the insignificant designation threshold from Rule 62-213.430(6), F.A.C. VOC and HAP emissions, which includes methanol, will be controlled by limiting the product throughput and submerged filling pursuant to Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards.

[Note: This emission unit is not subject to 40 CFR 60, Subpart Kb since the tank was constructed prior to 1984 and no known modifications have occurred since this date. This emission unit is regulated under Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards.]

Essential Potential to Emit (PTE) Parameters

F.1. Permitted Capacity. The maximum allowable methanol throughput rate is as follows:

EU No.	Gallons/12-Consecutive Month Period
-019	3,000,000

[Rules 62-4.160(2), 62-210.200(PTE), F.A.C., and Air Construction Permit No. 0570373-015-AC.]

F.2. Hours of Operation. This emissions units may operate continuously (8,760 hours/year). [Rule 62-210.200(PTE), F.A.C. and Air Construction Permit No. 0570373-015-AC.]

Emission Limitations and Standards

Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

F.3. In order to establish the facility as a synthetic non-Title V source for Hazardous Air Pollutants (HAP), the HAP, as defined in Rule 62-210.200, F.A.C., emissions shall be less than 10 tons in any 12 consecutive month period for any individual HAP, and less than 25 tons in any 12 consecutive month period for any combination of HAPs. [Rule 62-210.200, F.A.C., Definitions-Potential to Emit (PTE), Major Source of Air Pollution, and Synthetic Non-Title V Source; and Air Construction Permit No. 0570373-015-AC]

Work Practice Standards

F.4. The permittee shall comply with the following work and operational practice requirements:

(a) The tank shall be maintained to retain the structure, roof type, and color characteristics described in the application.
(b) Utilize submerged filling techniques (bottom loading) to load the storage tank.
(c) The tank shall be clearly identified to denote product contained within.

[Rules 62-296.320(1)(a) and 62-4.070(3), F.A.C. and Air Construction Permit No. 0570373-015-AC]

Test Methods and Procedures

Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

F.5. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

F.6. The permittee shall annually estimate the Standing (Breathing) loss and Working loss for the tank using the most recent version of the Tanks Program and report the losses as a part of the Annual Operating Report and the record keeping of Specific Condition F.8. [Rules 62-210.370(3) and 62-4.070(3), F.A.C., and Construction Permit Nos. 0570373-014-AC and 0570373-015-AC]

F.7. The permittee shall annually perform a visual inspection of the tank, associated piping system and pump for rust, cracks or leaks. Records of the inspections including any corrective action taken shall be maintained for a period of at least 5 years from the date of the inspection. [Rules 62-213.440(1)(b) and 62-4.070(3), F.A.C.]

Recordkeeping and Reporting Requirements

F.8. Compliance with emission limitations/restrictions of Specific Condition Nos. F.1. and F.3. shall be demonstrated, in part, by use of monthly records commencing on the effective date of this permit. The records shall be retained at least for the most recent five year period. The record shall be made available to the Environmental Protection Commission of Hillsborough County, the Department, or federal air pollution agency upon request. The records shall include, but are not limited to, the following:

(a) Month, year
(b) Material throughput (gal)
(c) Rolling 12-month total of the methanol handled through the tank
[Rules 62-213.440(1)(b)1.b. and 62-4.070(3), F.A.C.]

F.9. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

Subsection G. Emissions Unit 020

The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
-020	Five Digester Generator Engines

Sludge generated in the wastewater treatment process is fermented in the heated sludge digester tanks. Anaerobic bacteria aid in the sludge decomposition process for a period of time until all harmful microorganisms contained in the sludge are destroyed. The sludge decomposition process generates digester gas (a mixture of approximately 60% methane, 30% CO_2, nitrogen, and other impurities) which is fed to the five 0.5 MW digester gas fired generator RICE, which generate a portion of the electricity required to run the wastewater treatment plant. The five digester generators are not equipped with add-on controls, so the emissions are vented directly to the atmosphere. The engines are five Waukesha VHP-L7042 GU engines, 4 stroke spark ignition, rated at 670.5 bhp, fired exclusively on digester gas. The maximum total heat input rate is 5.6 MMBtu/hr based on a digester gas heating value of 621 Btu/cf and a fuel flow rate of 9,000 cf/hr.

This emission unit is subject to 40 CFR 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary RICE. This emission unit is not subject to 40 CFR 60, Subpart IIII or JJJJ since the engines were constructed in between 1984 and 1987, and there are no known modifications since then. Emissions are controlled by operation and maintenance practices and minimizing emissions during startup, shutdown, and malfunction.

Essential Potential to Emit (PTE) Parameters

G.1. Permitted Capacity. The maximum allowable heat input rate is as follows:

EU No.	MMBtu/hr Heat Input	MMCF/12-Consecutive Month Period	Fuel Type
-020	5.6	78.8	Digester Gas

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C., and Permit No. 0570373-019-AC]

G.2. Hours of Operation. These emissions units may operate continuously (8,760 hours/year). [Rule 62-210.200(PTE), F.A.C. and Permit No. 0570373-019-AC]

G.3. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

Emission Limitations and Standards

{Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

G.4. Visible Emissions. Visible emissions from the digester generators shall not exceed 20% opacity. [Rule 62-296.320(4)(b)1., F.A.C. and Air Construction Permit 0570373-019-AC]

G.5. [Reserved].

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

G.6. Excess Emissions Allowed. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

G.7. Excess Emissions Allowed. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

G.8. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Test Methods and Procedures

{Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

G.9. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-297.401, F.A.C. and Air Construction Permit No. 0570373-019-AC]

G.10. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

G.11. Annual Compliance Tests Required. During each federal fiscal year (October 1st to September 30th), each digester generator shall be tested to demonstrate compliance with the emission standard for opacity. [Rule 62-297.310(7), F.A.C. and Permit No. 0570373-019-AC]

G.12. Operating Rate During Testing. Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 90-100% of the rated capacity of 1.1 MMBtu/hr per engine, for a total of 5.6 MMBtu/hr. If it is impracticable to test at capacity, then the source may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Environmental Protection Commission of Hillsborough County. Failure to submit the input rates, actual operating conditions may invalidate the test. [Construction Permit 0570373-010-AC and Rule 62-297.310(2), F.A.C.]

G.13. The required minimum period of observation for a EPA Method 9 compliance test shall be thirty (30) minutes. The opacity test observation period shall include the period during which the emissions unit is operating at capacity as defined in Specific Condition G.12. Exceptions to these requirements are as follows:

(a) The minimum observation period for opacity tests conducted by the Environmental Protection Commission of Hillsborough County to verify the day-to-day continuing compliance of a unit or activity shall be twelve minutes. [Rule 62-297.310(4)(a), F.A.C.]

Monitoring, Recordkeeping, and Reporting Requirements

G.14. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

G.15. The permittee shall maintain monthly records and 12-month rolling totals of the hours of operation and the digester gas fuel usage for the digester generators.
[Rule 62-213.440(1)(b)1.b., F.A.C. and Air Construction Permit No. 0570373-019-AC]

G.16. The following inspections and maintenance shall be conducted on the schedule specified:

- (a) Every 1,440 hours of operation or annually, whichever comes first:
  - (1) Change engine oil and filter.
  - (2) Replace engine intake air filter.
  - (3) Inspect spark plugs and replace as necessary.
  - (4) Inspect all hoses and belts and replace as necessary.
- (b) Annually
  - (1) Conduct maintenance on the engine cooling system in accordance with the manufacturer’s specifications.
  - (2) Test all engine shut-down devices.

[40 CFR 63.6603 and Rule 62-4.070(3), F.A.C.]

G.17. At all times the permittee shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with the manufacturer's emission-related operation and maintenance instructions and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if the levels required have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605 and 63.6640]

G.18. The permittee shall keep the following records:
(a) A copy of each notification and report that was submitted, including all documentation supporting any Initial Notification or Notification of Compliance Status, according to the requirement in §63.10(b)(2)(xiv).
(b) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment).
(c) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).
(d) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
[40 CFR 63.6655]

Other Requirements

G.19. Federal 40 CFR 63 NESHAP Subpart ZZZZ Requirements - The existing stationary engines in EU ID No. 020 are required to comply with all the applicable requirements of NESHAP 40 CFR 63 Subpart ZZZZ (National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE)), which is attached to this permit. The compliance date for EU 020 is October 19, 2013. [40 CFR 63 Subpart ZZZZ, Rule 62-204.800, F.A.C., and Rule 62-4.070(3), F.A.C.]

The Following Appendices Are Enforceable Parts of This Permit:

Appendix A, Glossary.
Appendix CAM, Compliance Assurance Monitoring Plan.
Appendix I, List of Insignificant Emissions Units and/or Activities.
Appendix NESHAP, Subpart A – General Provisions.
Appendix NESHAP, Subpart ZZZZ.
Appendix RR, Facility-wide Reporting Requirements.
Appendix TR, Facility-wide Testing Requirements.
Appendix TV, Title V General Conditions.
Appendix U, List of Unregulated Emissions Units and/or Activities.

REFERENCED ATTACHMENTS.

The Following Attachments Are Included for Applicant Convenience:

Table H, Permit History.
Table 1, Summary of Air Pollutant Standards and Terms.
Table 2, Compliance Requirements.

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January 4, 2013

MWH Global
1000 N. Ashley St. Suite 1000
Tampa, FL 33602

Gas Analysis Results for the Tampa Howard F Curren AWTP

Dear Mr. Broome:

On December 12, 2012, four(4) gas samples were received by the Robinson Group, LLC for analysis from the Tampa Howard F. Curren AWTP. The samples were sent in to be analyzed to determine the main constituents in the AWTP digester biogas. Four(4) tedlar bags were received containing two(2) gas samples each from the pre and post filter test point locations. The samples were tested for major gases, VOC's, siloxanes and H2S in accordance with the following EPA test methods: Major Gases to EPA Method 3C, Volatile Organic Compounds, Siloxanes and Sulfur Compounds to EPA Method TO-15. The testing was requested as part of an amendment to the Biogas Use Improvements Study being performed. Listed below is a summary of the gas analysis and a list of the constituents of concern.

Summary of Gas Testing Results: Post Filter

Major Gases by EPA Method 3C

Carbon Dioxide	35.9 %
Methane	52.0 %
Nitrogen	8.90 %
Oxygen	3.21 %

Siloxanes by EPA Method TO-15

Hexamethylcyclotrisiloxane (D3)	10.4 ppbv 100 pbbv
Octamethylcyclotetrasiloxane (D4)	398 ppbv
Decamethylcyclopentasiloxane (D5)	1,050 ppbv

Sulfur Compounds by EPA Method TO-15

Hydrogen Sulfide	135,000 ppbv
Methyl Mercaptan	804 ppbv
Ethyl Mercaptan	528 ppbv
Dimethyl Sulfide	385 ppbv
t-Butyl Mercaptan	322 ppbv

Summary of Gas Testing Results: Pre - Filter

Major Gases by EPA Method 3C

Carbon Dioxide	36.3 %
Methane	54.4 %
Nitrogen	7.64 %
Oxygen	1.60 %

Siloxanes by EPA Method TO-15

Hexamethylcyclotrisiloxane (D3)	11.5 ppbv
Octamethylcyclotetrasiloxane (D4)	444 ppbv
Decamethylcyclopentasiloxane (D5)	649 ppbv

Sulfur Compounds by EPA Method TO-15

Hydrogen Sulfide	68,900 ppbv
Methyl Mercaptan	717 ppbv
Ethyl Mercaptan	453 ppbv
Dimethyl Sulfide	348 ppbv
Isopropyl Mercaptan	72.6 ppbv
t-Butyl Mercaptan	274 ppbv

As shown, the results of the gas analysis revealed concentration levels of siloxanes and sulfur compounds typical of digester biogas. Sulfur, siloxane and moisture removal are critical to control and remove for protection of cogeneration engines, turbines and heat recovery systems. Proper control of these constituents results in longer engine life, reduced maintenance costs and lower operating costs. This is important since historical data indicates that damage starts to occur to engine oil, valve, cylinders, heads, liners, spark plugs and piston crowns at 0.5 ppm total siloxanes.

The test analysis also showed that the levels of siloxanes and sulfurs following the post filter were higher than those seen in the pre-filter sample. This is called the "roll over effect" and is caused by desorption of previously adsorbed non methane organics in the filters. If the filters are standard activated carbon versus a specific media designed for siloxane and sulfur removal such as SAG, the effect will happen faster. The higher molecular weight non methane organics, such as D5 siloxane adsorb quickly to the carbon followed by the lower molecular weight D4, D3 and chlorinated or toluene type compounds. This will be further enhanced if the molar volume of the D5 siloxane is higher as in this case. When the filters become saturated, the media starts releasing or dumping forward the lighter molecular weight materials in place of the heavier D5. This is referred to as "preferential adsorption". This will result in the total inlet filter compounds actually being less than the outlet filter.

Sulfur may also act to shorten the filter life based on its higher molar volume than the other non methane volatile organics. On standard carbon filters, sulfur can help to blind off some of the pore structure that is needed to absorb the D5 siloxanes. This can cause a premature breakthrough condition. It is theorized that sulfur absorption is what is contributing to the siloxane break though at this site. Sulfur removal ahead of these filters would preclude this effect. This can be accomplished with a SulfrPack ST or similar unit.

This condition is very important to manage correctly to protect cogeneration and heat recovery equipment. A well designed system like a SAGPack can provide the right gas quality management to the cogen. This is done by cleaning and compressing the gas along with sulfur and siloxane removal, so these compounds never exit the final filter.

The gas analysis data indicates the demographic of this plant is mainly household and some light industry. This information is useful because it gives the system designer the ability to model the future gas conditions which help in the design of long term capacities for the gas conditioning and cogeneration equipment.

Any improvements in mixing, acid phase processing, addition of fats oils and greases, ferric, temperature changes such as going from mesophilic to thermophilic digestion and cell lysis will increase the available % of methane and significantly increase the volume of non methane VOC’s, siloxanes and sulfurs.

In conclusion, RG recommends the use of a SulfrPack ST unit on the wet inlet gas followed by a SAGPack with SAG units to compress, dry and remove the siloxanes before the engines. The Robinson Group guarantees the gas quality for a period of 10 years with a service agreement. This guarantee is based on detection limit removal of siloxanes to 0.3 mg/m3 of digester gas, per individual siloxane and 100 ppb total for all combined siloxanes.

I trust that this report provides you with the information that you have requested. Please contact me at email: jyelpo@robinson-group.com or cell: 908-930-5322 if you have any technical questions.

Sincerely,

Joseph Yelpo
East Regional Sales Manager – Robinson Group, LLC

Appendix

Robinson Group, LLC Analytical Report

ROBINSON
GROUP, LLC
BioGas Powered Energy Solutions

Analytical Report

WO#: **1212067**
Date Reported: **12/18/2012**

Client: Robinson Group, LLC **Collection Date:** 12/11/2012 9:20:00 A
Project: Tampa
Lab ID: 1212067-001 **Matrix:** Air
Client Sample ID: Post Filter

Analyses	Result	RL	Qual	Units	DF	Date Analyzed
Major Gases by EPA Method 3C				Batch ID: R6941		Analyst: MD
Carbon Dioxide	35.9	0.0500		%	1	12/12/2012 3:18:08 PM
Carbon Monoxide	ND	0.0500		%	1	12/12/2012 3:18:08 PM
Methane	52.0	0.0500		%	1	12/12/2012 3:18:08 PM
Nitrogen	8.90	0.0500		%	1	12/12/2012 3:18:08 PM
Oxygen	3.21	0.0500		%	1	12/12/2012 3:18:08 PM
Hydrogen	ND	0.0500		%	1	12/12/2012 3:18:08 PM
BTU	525			BTU/ft³	1	12/12/2012 3:18:08 PM
Siloxanes by EPA Method TO-15				Batch ID: R6935		Analyst: MD
Dodecamethylpentasiloxane (L5)	ND	5.00		ppbv	1	12/12/2012 9:39:00 PM
Pentamethyldisiloxane	ND	5.00		ppbv	1	12/12/2012 9:39:00 PM
Hexamethyldisiloxane-L2 (MM)	ND	5.00		ppbv	1	12/12/2012 9:39:00 PM
Hexamethylcyclotrisiloxane (D3)	10.4	5.00		ppbv	1	12/12/2012 9:39:00 PM
Octamethyltrisiloxane-L3 (MDM)	54.2	5.00		ppbv	1	12/12/2012 9:39:00 PM
Octamethylcyclotetrasiloxane (D4)	398	5.00		ppbv	1	12/12/2012 9:39:00 PM
Decamethyltetrasiloxane-L4 (MD2M)	ND	5.00		ppbv	1	12/12/2012 9:39:00 PM
Decamethylcyclopentasiloxane (D5)	1,050	5.00		ppbv	1	12/12/2012 9:39:00 PM
Dodecamethylcyclohexasiloxane (D6)	ND	5.00		ppbv	1	12/12/2012 9:39:00 PM
Surr: 4-Bromofluorobenzene	102	70-130		%REC	1	12/12/2012 9:39:00 PM
Sulfur Compounds by EPA Method TO-15				Batch ID: R6936		Analyst: MD
Hydrogen Sulfide	135,000	5.00		ppbv	1	12/12/2012 9:39:00 PM
Carbon Disulfide	5.40	5.00		ppbv	1	12/12/2012 9:39:00 PM
Methyl Mercaptan	804	5.00		ppbv	1	12/12/2012 9:39:00 PM
Ethyl Mercaptan	528	5.00		ppbv	1	12/12/2012 9:39:00 PM
Dimethyl Sulfide	385	5.00		ppbv	1	12/12/2012 9:39:00 PM
Carbonyl Sulfide	ND	5.00		ppbv	1	12/12/2012 9:39:00 PM
Isopropyl Mercaptan	84.4	5.00		ppbv	1	12/12/2012 9:39:00 PM
t-Butyl Mercaptan	322	5.00		ppbv	1	12/12/2012 9:39:00 PM
n-Propyl Mercaptan	ND	5.00		ppbv	1	12/12/2012 9:39:00 PM
Isobutyl Mercaptan	116	5.00		ppbv	1	12/12/2012 9:39:00 PM
n-Butyl Mercaptan	ND	5.00		ppbv	1	12/12/2012 9:39:00 PM
Dimethyl Disulfide	ND	5.00		ppbv	1	12/12/2012 9:39:00 PM
Surr: 4-Bromofluorobenzene	109	70-130		%REC	1	12/12/2012 9:39:00 PM
Volatile Organic Compounds by EPA Method TO-15				Batch ID: R6937		Analyst: MD
Propylene	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Dichlorodifluoromethane (CFC-12)	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
Chloromethane	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM

Qualifiers:	B	Analyte detected in the associated Method Blank	D	Dilution was required
	E	Value above quantitation range	H	Holding times for preparation or analysis exceeded
	J	Analyte detected below quantitation limits	ND	Not detected at the Reporting Limit
	RL	Reporting Limit	S	Spike recovery outside accepted recovery limits

Analytical Report

WO#: **1212067**
Date Reported: **12/18/2012**

Client: Robinson Group, LLC
Collection Date: 12/11/2012 9:20:00 A
Project: Tampa
Lab ID: 1212067-001
Matrix: Air
Client Sample ID: Post Filter

Volatile Organic Compounds by EPA Method TO-15

Batch ID: R6937 Analyst: MD

Analyses	Result	RL	Qual	Units	DF	Date Analyzed
Dichlorotetrafluoroethane (CFC-114)	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Vinyl chloride	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
1,3-Butadiene	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Bromomethane	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Trichlorofluoromethane (CFC-11)	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
Chloroethane	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Acrolein	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
1,1-Dichloroethene (DCE)	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Acetone	7.20	1.00		ppbv	1	12/12/2012 9:39:00 PM
Isopropyl Alcohol	4.80	1.00		ppbv	1	12/12/2012 9:39:00 PM
Methylene chloride	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Carbon disulfide	4.00	0.200		ppbv	1	12/12/2012 9:39:00 PM
trans-1,2-Dichloroethene	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Methyl tert-butyl ether (MTBE)	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Hexane	175	0.200		ppbv	1	12/12/2012 9:39:00 PM
1,1-Dichloroethane	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Vinyl acetate	ND	1.00		ppbv	1	12/12/2012 9:39:00 PM
cis-1,2-Dichloroethene	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
(MEK) 2-Butanone	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Ethyl acetate	ND	1.00		ppbv	1	12/12/2012 9:39:00 PM
Chloroform	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Tetrahydrofuran	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
1,1,1-Trichloroethane	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Carbon tetrachloride	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
1,2-Dichloroethane	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Benzene	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Cyclohexane	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Trichloroethene (TCE)	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
1,2-Dichloropropane	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Methyl methacrylate	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
Dichlorobromomethane	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
1,4-Dioxane	ND	1.00		ppbv	1	12/12/2012 9:39:00 PM
cis-1,3-dichloropropene	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Toluene	45.1	0.200		ppbv	1	12/12/2012 9:39:00 PM
trans-1,3-dichloropropene	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
1,1,2-Trichloroethane (TCA)	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Tetrachloroethene (PCE)	39.2	0.300		ppbv	1	12/12/2012 9:39:00 PM
Dibromochloromethane	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
1,2-Dibromoethane (EDB)	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Chlorobenzene	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
Ethylbenzene	57.9	0.300		ppbv	1	12/12/2012 9:39:00 PM
m,p-Xylene	86.7	0.200		ppbv	1	12/12/2012 9:39:00 PM
o-Xylene	58.2	0.200		ppbv	1	12/12/2012 9:39:00 PM

Qualifiers:

B	Analyte detected in the associated Method Blank	D	Dilution was required
E	Value above quantitation range	H	Holding times for preparation or analysis exceeded
J	Analyte detected below quantitation limits	ND	Not detected at the Reporting Limit
RL	Reporting Limit	S	Spike recovery outside accepted recovery limits

Client: Robinson Group, LLC **Collection Date:** 12/11/2012 9:20:00 A
Project: Tampa
Lab ID: 1212067-001 **Matrix:** Air
Client Sample ID: Post Filter

Analyses	**Result**	**RL**	**Qual**	**Units**	**DF**	**Date Analyzed**

Volatile Organic Compounds by EPA Method TO-15

Batch ID: R6937 Analyst: MD

Styrene	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
Bromoform	ND	0.200		ppbv	1	12/12/2012 9:39:00 PM
1,1,2,2-Tetrachloroethane	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
1,3,5-Trimethylbenzene	49.3	0.300		ppbv	1	12/12/2012 9:39:00 PM
1,2,4-Trimethylbenzene	95.7	0.300		ppbv	1	12/12/2012 9:39:00 PM
Benzyl chloride	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
4-Ethyltoluene	25.8	0.300		ppbv	1	12/12/2012 9:39:00 PM
1,3-Dichlorobenzene	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
1,4-Dichlorobenzene	21.8	0.300		ppbv	1	12/12/2012 9:39:00 PM
1,2-Dichlorobenzene	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
1,2,4-Trichlorobenzene	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
Hexachlorobutadiene	ND	1.00		ppbv	1	12/12/2012 9:39:00 PM
Naphthalene	ND	0.300		ppbv	1	12/12/2012 9:39:00 PM
2-Hexanone	ND	1.00		ppbv	1	12/12/2012 9:39:00 PM
4-Methyl-2-pentanone (MIBK)	ND	1.00		ppbv	1	12/12/2012 9:39:00 PM
CFC-113	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Heptane	ND	0.500		ppbv	1	12/12/2012 9:39:00 PM
Surr: 4-Bromofluorobenzene	121	70-130		%REC	1	12/12/2012 9:39:00 PM
TIC: 1,3,6,10-Dodecatetraene, 3,7,1	91.5		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: 1-Decanol, 2-ethyl-	134		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: 1-Hexene, 5,5-dimethyl-	69.4		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: 2-Heptanethiol, 2-methyl-	106		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: 3-Hydroxymandelic acid, ethyl	324		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: 5-Undecyne	71.5		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Benzene, 1-methyl-4-(1-methyle	1,770		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Benzene, 2-ethyl-1,3-dimethyl-	104		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Benzeneacetaldehyde, .alpha.-m	109		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Benzeneethanamine, N-butyl-.be	1,200		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Bicyclo(2.2.1)heptane, 2,2,3-t	77.8		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Carbon dioxide	410		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Cyclohexane, (2-methylpropyl)-	155		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Cyclohexane, 1,2,4-trimethyl-	117		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Cyclohexane, 1,4-dimethyl-	70.9		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Cyclohexane, 1-methyl-3-(1-met	86.9		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Cyclohexene, 1-methyl-5-(1-met	74.9		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Cyclohexene, 4-methyl-1-(1-met	81.3		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Cyclotetrasiloxane, octamethyl (24.7)	147		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Decane (25)	424		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Decane (25.1)	427		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Diaziridine,1,3,3-trimethyl-	74.7		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Dodecane, 2,6,10-trimethyl-	88.6		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Heptane, 2,2,4,6,6-pentamethyl	198		N	ppbv	1	12/12/2012 9:39:00 PM

Qualifiers:	B	Analyte detected in the associated Method Blank	D	Dilution was required
	E	Value above quantitation range	H	Holding times for preparation or analysis exceeded
	J	Analyte detected below quantitation limits	ND	Not detected at the Reporting Limit
	RL	Reporting Limit	S	Spike recovery outside accepted recovery limits

Client: Robinson Group, LLC

Collection Date: 12/11/2012 9:20:00 A

Project: Tampa

Lab ID: 1212067-001

Matrix: Air

Client Sample ID: Post Filter

Volatile Organic Compounds by EPA Method TO-15

Batch ID: R6937 Analyst: MD

Analyses	Result	RL	Qual	Units	DF	Date Analyzed
TIC: Heptane, 2,3,4-trimethyl-	102		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Heptane, 3-((ethenyloxy)methyl	105		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Heptane, 3-ethyl-2-methyl-	71.2		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Heptane, 5-ethyl-2,2,3-trimeth	166		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Hex-4-yn-3-one, 2,2-dimethyl-	75.7		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Hexane, 1-(hexyloxy)-3-methyl-	76.3		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Hexane, 2,4-dimethyl-	208		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Limonene	166		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Methan-d3-ol	251		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Methanethiol	102		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Methyl fluoride	624		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Naphthalene, decahydro-	101		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Naphthalene, decahydro-2,6-dim	68.6		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Nerol, methyl ether	69.8		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Octane, 2,6-dimethyl-	342		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Pentane, 2-isocyano-2,4,4-trim	107		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Sulfurous acid, isobutyl 2-pen	144		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: trans,cis-1,8-Dimethylspiro(4. (28.7)	73.8		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: trans,cis-1,8-Dimethylspiro(4. (29.4)	64.6		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Tridecane	507		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Undecane	285		N	ppbv	1	12/12/2012 9:39:00 PM
TIC: Undecane, 6-methyl-	104		N	ppbv	1	12/12/2012 9:39:00 PM

Qualifiers:

B	Analyte detected in the associated Method Blank	D	Dilution was required
E	Value above quantitation range	H	Holding times for preparation or analysis exceeded
J	Analyte detected below quantitation limits	ND	Not detected at the Reporting Limit
RL	Reporting Limit	S	Spike recovery outside accepted recovery limits

Client: Robinson Group, LLC
Collection Date: 12/11/2012 9:20:00 A
Project: Tampa
Lab ID: 1212067-002
Matrix: Air
Client Sample ID: Pre Filter

Major Gases by EPA Method 3C

Batch ID: R6941 Analyst: MD

Analyses	Result	RL	Qual	Units	DF	Date Analyzed
Carbon Dioxide	36.3	0.0500		%	1	12/12/2012 3:18:08 PM
Carbon Monoxide	ND	0.0500		%	1	12/12/2012 3:18:08 PM
Methane	54.4	0.0500		%	1	12/12/2012 3:18:08 PM
Nitrogen	7.64	0.0500		%	1	12/12/2012 3:18:08 PM
Oxygen	1.60	0.0500		%	1	12/12/2012 3:18:08 PM
Hydrogen	ND	0.0500		%	1	12/12/2012 3:18:08 PM
BTU	550			BTU/ft³	1	12/12/2012 3:18:08 PM

Siloxanes by EPA Method TO-15

Batch ID: R6935 Analyst: MD

Analyses	Result	RL	Qual	Units	DF	Date Analyzed
Dodecamethylpentasiloxane (L5)	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Pentamethyldisiloxane	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Hexamethyldisiloxane-L2 (MM)	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Hexamethylcyclotrisiloxane (D3)	11.5	5.00		ppbv	1	12/12/2012 8:55:00 PM
Octamethyltrisiloxane-L3 (MDM)	61.6	5.00		ppbv	1	12/12/2012 8:55:00 PM
Octamethylcyclotetrasiloxane (D4)	444	5.00		ppbv	1	12/12/2012 8:55:00 PM
Decamethyltetrasiloxane-L4 (MD2M)	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Decamethylcyclopentasiloxane (D5)	649	5.00		ppbv	1	12/12/2012 8:55:00 PM
Dodecamethylcyclohexasiloxane (D6)	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Surr: 4-Bromofluorobenzene	104	70-130		%REC	1	12/12/2012 8:55:00 PM

Sulfur Compounds by EPA Method TO-15

Batch ID: R6936 Analyst: MD

Analyses	Result	RL	Qual	Units	DF	Date Analyzed
Hydrogen Sulfide	68,900	5.00		ppbv	1	12/12/2012 8:55:00 PM
Carbon Disulfide	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Methyl Mercaptan	717	5.00		ppbv	1	12/12/2012 8:55:00 PM
Ethyl Mercaptan	453	5.00		ppbv	1	12/12/2012 8:55:00 PM
Dimethyl Sulfide	348	5.00		ppbv	1	12/12/2012 8:55:00 PM
Carbonyl Sulfide	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Isopropyl Mercaptan	72.6	5.00		ppbv	1	12/12/2012 8:55:00 PM
t-Butyl Mercaptan	274	5.00		ppbv	1	12/12/2012 8:55:00 PM
n-Propyl Mercaptan	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Isobutyl Mercaptan	94.6	5.00		ppbv	1	12/12/2012 8:55:00 PM
n-Butyl Mercaptan	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Dimethyl Disulfide	ND	5.00		ppbv	1	12/12/2012 8:55:00 PM
Surr: 4-Bromofluorobenzene	112	70-130		%REC	1	12/12/2012 8:55:00 PM

Volatile Organic Compounds by EPA Method TO-15

Batch ID: R6937 Analyst: MD

Analyses	Result	RL	Qual	Units	DF	Date Analyzed
Propylene	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Dichlorodifluoromethane (CFC-12)	ND	0.300		ppbv	1	12/12/2012 8:55:00 PM
Chloromethane	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM

Qualifiers:				
	B	Analyte detected in the associated Method Blank	D	Dilution was required
	E	Value above quantitation range	H	Holding times for preparation or analysis exceeded
	J	Analyte detected below quantitation limits	ND	Not detected at the Reporting Limit
	RL	Reporting Limit	S	Spike recovery outside accepted recovery limits

ROBINSON
GROUP, LLC
BioGas Powered Energy Solutions

Analytical Report

WO#: **1212067**

Date Reported: **12/18/2012**

Client: Robinson Group, LLC

Collection Date: 12/11/2012 9:20:00 A

Project: Tampa

Lab ID: 1212067-002

Matrix: Air

Client Sample ID: Pre Filter

Volatile Organic Compounds by EPA Method TO-15

Batch ID: R6937   Analyst: MD

Analyses	Result	RL	Qual	Units	DF	Date Analyzed
Dichlorotetrafluoroethane (CFC-114)	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Vinyl chloride	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
1,3-Butadiene	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Bromomethane	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Trichlorofluoromethane (CFC-11)	ND	0.300		ppbv	1	12/12/2012 8:55:00 PM
Chloroethane	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Acrolein	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
1,1-Dichloroethene (DCE)	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
Acetone	3.92	1.00		ppbv	1	12/12/2012 8:55:00 PM
Isopropyl Alcohol	2.64	1.00		ppbv	1	12/12/2012 8:55:00 PM
Methylene chloride	9.36	0.500		ppbv	1	12/12/2012 8:55:00 PM
Carbon disulfide	2.16	0.200		ppbv	1	12/12/2012 8:55:00 PM
trans-1,2-Dichloroethene	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
Methyl tert-butyl ether (MTBE)	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
Hexane	162	0.200		ppbv	1	12/12/2012 8:55:00 PM
1,1-Dichloroethane	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
Vinyl acetate	ND	1.00		ppbv	1	12/12/2012 8:55:00 PM
cis-1,2-Dichloroethene	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
(MEK) 2-Butanone	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Ethyl acetate	ND	1.00		ppbv	1	12/12/2012 8:55:00 PM
Chloroform	2.16	0.200		ppbv	1	12/12/2012 8:55:00 PM
Tetrahydrofuran	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
1,1,1-Trichloroethane	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
Carbon tetrachloride	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
1,2-Dichloroethane	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
Benzene	1.92	0.200		ppbv	1	12/12/2012 8:55:00 PM
Cyclohexane	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
Trichloroethene (TCE)	7.44	0.200		ppbv	1	12/12/2012 8:55:00 PM
1,2-Dichloropropane	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Methyl methacrylate	ND	0.300		ppbv	1	12/12/2012 8:55:00 PM
Dichlorobromomethane	ND	0.300		ppbv	1	12/12/2012 8:55:00 PM
1,4-Dioxane	ND	1.00		ppbv	1	12/12/2012 8:55:00 PM
cis-1,3-dichloropropene	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Toluene	47.7	0.200		ppbv	1	12/12/2012 8:55:00 PM
trans-1,3-dichloropropene	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
1,1,2-Trichloroethane (TCA)	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Tetrachloroethene (PCE)	27.1	0.300		ppbv	1	12/12/2012 8:55:00 PM
Dibromochloromethane	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
1,2-Dibromoethane (EDB)	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
Chlorobenzene	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
Ethylbenzene	57.3	0.300		ppbv	1	12/12/2012 8:55:00 PM
m,p-Xylene	87.0	0.200		ppbv	1	12/12/2012 8:55:00 PM
o-Xylene	58.6	0.200		ppbv	1	12/12/2012 8:55:00 PM

Qualifiers:

B	Analyte detected in the associated Method Blank	D	Dilution was required
E	Value above quantitation range	H	Holding times for preparation or analysis exceeded
J	Analyte detected below quantitation limits	ND	Not detected at the Reporting Limit
RL	Reporting Limit	S	Spike recovery outside accepted recovery limits

Analytical Report

WO#: **1212067**
Date Reported: **12/18/2012**

Client: Robinson Group, LLC
Collection Date: 12/11/2012 9:20:00 A
Project: Tampa
Lab ID: 1212067-002
Matrix: Air
Client Sample ID: Pre Filter

Volatile Organic Compounds by EPA Method TO-15

Batch ID: R6937 Analyst: MD

Analyses	Result	RL	Qual	Units	DF	Date Analyzed
Styrene	ND	0.300		ppbv	1	12/12/2012 8:55:00 PM
Bromoform	ND	0.200		ppbv	1	12/12/2012 8:55:00 PM
1,1,2,2-Tetrachloroethane	ND	0.300		ppbv	1	12/12/2012 8:55:00 PM
1,3,5-Trimethylbenzene	54.0	0.300		ppbv	1	12/12/2012 8:55:00 PM
1,2,4-Trimethylbenzene	114	0.300		ppbv	1	12/12/2012 8:55:00 PM
Benzyl chloride	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
4-Ethyltoluene	33.8	0.300		ppbv	1	12/12/2012 8:55:00 PM
1,3-Dichlorobenzene	17.5	0.300		ppbv	1	12/12/2012 8:55:00 PM
1,4-Dichlorobenzene	21.7	0.300		ppbv	1	12/12/2012 8:55:00 PM
1,2-Dichlorobenzene	ND	0.300		ppbv	1	12/12/2012 8:55:00 PM
1,2,4-Trichlorobenzene	ND	0.300		ppbv	1	12/12/2012 8:55:00 PM
Hexachlorobutadiene	ND	1.00		ppbv	1	12/12/2012 8:55:00 PM
Naphthalene	ND	0.300		ppbv	1	12/12/2012 8:55:00 PM
2-Hexanone	ND	1.00		ppbv	1	12/12/2012 8:55:00 PM
4-Methyl-2-pentanone (MIBK)	ND	1.00		ppbv	1	12/12/2012 8:55:00 PM
CFC-113	ND	0.500		ppbv	1	12/12/2012 8:55:00 PM
Heptane	101	0.500		ppbv	1	12/12/2012 8:55:00 PM
Surr: 4-Bromofluorobenzene	129	70-130		%REC	1	12/12/2012 8:55:00 PM
TIC: Carbon dioxide	97.4		N	ppbv	1	12/12/2012 8:55:00 PM
TIC: Methane, chlorotrinitro-	81.4		N	ppbv	1	12/12/2012 8:55:00 PM
TIC: Nitrosyl chloride	45.4		N	ppbv	1	12/12/2012 8:55:00 PM

Qualifiers:

B	Analyte detected in the associated Method Blank	D	Dilution was required
E	Value above quantitation range	H	Holding times for preparation or analysis exceeded
J	Analyte detected below quantitation limits	ND	Not detected at the Reporting Limit
RL	Reporting Limit	S	Spike recovery outside accepted recovery limits

1212067

CHAIN OF CUSTODY

ROBINSON GROUP, LLC

Site Name & Location: Tampa

Company: MWH Americas, Inc.

Contact Name: Kenneth Broome

Address: 1000 N. Ashley Dr., Suite 1000

City: Tampa State/Zip: FL 33602

Phone: 813-221-1981 E-mail:

Ship Samples To:

Robinson Group, LLC
1311 N. 35th St.
Seattle, WA 98103

Questions?
Phone: 425-420-1979
Fax: 425-491-7740
Email: service@robinson-group.com

Additional Information:

Gas Flow Rate:

Gas Pressure: 4 PSI

Lab Turnaround Time (TAT)
Business Days (& Surcharge)

Check one:

- 5 Days (Standard) ✓
- 3 Days (+50%)
- 2 Days (+75%)
- Next Day (+100%)
- Same Day (+125%)

Origin of Sample (Circle One):
Landfill [✓ Digester] Ag. Blend
(If Ag or Blend, describe source and composition under comments.)

Total number of Tedlar bags: Four

Important: Do not fill more than 1/2 full!

Please Label ALL Tedlar bags

Gas Sample Identification	Date and Time Sampled	Lab Analysis (check ONLY the analyses needed)				Comments
		Major Gases	VOC 300+	Siloxane Series	Sulfur Series	
Example: Inlet 1	3/25/11 10:00 AM			✓	✓	Primary
1. Post Filter	12/11/12 9:20	✓	✓	✓	✓	
2. " Duplicate						
3. Pre Filter	12/11/12 9:20	✓	✓	✓	✓	
4. " Duplicate						

Custody Chain	Print Name	Signature (this form MUST be signed)	Date	Time	Courier:
Sampled by:	Jeovanni Ayala-Lugo	X	12/11/12	9:30 AM	Fed Ex
Relinquished by:	Claire Griggs	X	12/12/12	10:00	(Must be Priority Overnight!)
Received at Lab by:		X			

MWH

Howard F. Curren AWTP
Biogas Use Study

JUNE 2013

APPENDIX B

Table B-1

Heat Requirement Calculations

Heat to raise sludge temperature

	UNITS	MMADF	AADF	
Specific Heat of Sludge =	Btu/lb F	1.0	1.0	
Sludge tempertaure requirement =	deg F	98	98	
Cold Month Temp of Residuals	deg F	75	75	from City Staff
Warm Month Temp of Residuals	deg F	83	83	from City Staff
Weight of liquid sludge to digesters=	**lbs/day**	**3,753,000**	**3,305,349**	
Weight of liquid sludge to digesters=	**lbs/hr**	**156,375**	**137,723**	
Heat required to rise sludge temperature during on cold months	**BTU/Hr**	**4,222,125**	**3,718,518**	
Heat required to rise sludge temperature during on warm months	**BTU/Hr**	**2,720,925**	**2,396,378**	

Heat losses

Tank Losses

Heat Transfer Coefficients:

Above ground concrete wall	Btu/ft2*deg F*hr	0.9	Coefficients from Metcalf & Eddy (2003)
Below ground concrete wall	Btu/ft2*deg F*hr	0.25	
Digester concrete Floor	Btu/ft2*deg F*hr	0.50	
Floating Covers	Btu/ft2*deg F*hr	0.35	

		Digester Tanks 1-3	
Cold Month Average Temp	deg F	60	from NOAA
Warm Month Avg Temp	deg F	82	from NOAA
Average Conditions cold Temp	deg F	60	from NOAA
Average Conditions warm Temp	deg F	82	from NOAA
Tank Diameter	ft	75	
Exposed Sidewall Depth	ft	12	
Buried Sidewall Depth	ft	12	
Floor slope	ft/ft	0	
Center Depth	ft	0	
Total Wall Area (per tank)	**sq.ft**	**2,827**	
Total buried wall area (per tank)	**sq.ft**	**2,827**	
Total Floor Area (per tank)	**sq.ft**	**8,836**	
Total Roof Area (per tank)	**sq.ft**	**8,836**	

Conditions at MMDW

Cold months

		Digester Tanks 1-3
No of tanks		3
Wall losses per tank	**Btu/hr**	**121,933**
Floor losses per tank	**Btu/hr**	**82,835**
Roof Losses per tank	**Btu/hr**	**165,670**
Total losses per tank	**Btu/hr**	**370,438**
Total losses	**Btu/hr**	**1,111,314**

Warm months

Wall losses per tank	**Btu/hr**	**50,399**
Floor losses per tank	**Btu/hr**	**34,238**
Roof Losses per tank	**Btu/hr**	**68,477**
Total losses per tank	**Btu/hr**	**153,114**
Total losses	**Btu/hr**	**459,343**

Average conditions

Cold months

Wall losses per tank	**Btu/hr**	**121,933**
Floor losses per tank	**Btu/hr**	**82,835**
Roof Losses per tank	**Btu/hr**	**165,670**
Total losses per tank	**Btu/hr**	**370,438**
Total losses	**Btu/hr**	**1,111,314**

Warm months

Wall losses per tank	**Btu/hr**	**50,399**
Floor losses per tank	**Btu/hr**	**34,238**
Roof Losses per tank	**Btu/hr**	**68,477**
Total losses per tank	**Btu/hr**	**153,114**
Total losses	**Btu/hr**	**459,343**

		Digester Tank 4
Cold Month Average Temp	deg F	60
Warm Month Avg Temp	deg F	82
Average Conditions cold Temp	deg F	60
Average Conditions warm Temp	deg F	82
Tank Diameter	ft	75
Exposed Sidewall Depth	ft	12
Buried Sidewall Depth	ft	12
Floor slope	ft/ft	0.25
Center Depth	ft	9.375
Total Wall Area (per tank)	**sq.ft**	**2,827**
Total buried wall area (per tank)	**sq.ft**	**2,827**
Total Floor Area (per tank)	**sq.ft**	**9,108**
Total Roof Area (per tank)	**sq.ft**	**8,836**

Conditions at MMDW

Cold months		**Digester Tank 4**
No of tanks		1
Wall losses per tank	**Btu/hr**	**121,933**
Floor losses per tank	**Btu/hr**	**85,384**
Roof Losses per tank	**Btu/hr**	**165,670**
Total losses per tank	**Btu/hr**	**372,987**
Total losses	**Btu/hr**	**372,987**

Warm months

No of tanks		1
Wall losses per tank	**Btu/hr**	**50,399**
Floor losses per tank	**Btu/hr**	**35,292**
Roof Losses per tank	**Btu/hr**	**68,477**
Total losses per tank	**Btu/hr**	**154,168**
Total losses	**Btu/hr**	**154,168**

Average conditions

Cold months

No of tanks		1
Wall losses per tank	**Btu/hr**	**121,933**
Floor losses per tank	**Btu/hr**	**85,384**
Roof Losses per tank	**Btu/hr**	**165,670**
Total losses per tank	**Btu/hr**	**372,987**
Total losses	**Btu/hr**	**372,987**

Warm months

No of tanks		1
Wall losses per tank	**Btu/hr**	**50,399**
Floor losses per tank	**Btu/hr**	**35,292**
Roof Losses per tank	**Btu/hr**	**68,477**
Total losses per tank	**Btu/hr**	**154,168**
Total losses	**Btu/hr**	**154,168**

		Digester Tank 5
Cold Month Average Temp	deg F	60
Warm Month Avg Temp	deg F	82
Average Conditions cold Temp	deg F	60
Average Conditions warm Temp	deg F	82
Tank Diameter	ft	95
Exposed Sidewall Depth	ft	12.5
Buried Sidewall Depth	ft	13
Floor slope	ft/ft	0.25
Center Depth	ft	11.875
Total Wall Area (per tank)	**sq.ft**	**3,731**

Total buried wall area (per tank)	sq.ft	3,880
Total Floor Area (per tank)	sq.ft	14,613
Total Roof Area (per tank)	sq.ft	14,176

Conditions at MMDW

Cold months		**Digester Tank 5**
No of tanks		1
Wall losses per tank	Btu/hr	125,909
Floor losses per tank	Btu/hr	136,994
Roof Losses per tank	Btu/hr	265,808
Total losses per tank	Btu/hr	528,712
Total losses	Btu/hr	528,712

Warm months

No of tanks		1
Wall losses per tank	Btu/hr	52,042
Floor losses per tank	Btu/hr	56,624
Roof Losses per tank	Btu/hr	109,867
Total losses per tank	Btu/hr	218,534
Total losses	Btu/hr	218,534

Average conditions

Cold months

No of tanks		1
Wall losses per tank	Btu/hr	125,909
Floor losses per tank	Btu/hr	136,994
Roof Losses per tank	Btu/hr	265,808
Total losses per tank	Btu/hr	528,712
Total losses	Btu/hr	528,712

Warm months

No of tanks		1
Wall losses per tank	Btu/hr	52,042
Floor losses per tank	Btu/hr	56,624
Roof Losses per tank	Btu/hr	109,867
Total losses per tank	Btu/hr	218,534
Total losses	Btu/hr	218,534

		Digester Tanks 6 & 7
Cold Month Average Temp	deg F	60
Warm Month Avg Temp	deg F	82
Average Conditions cold Temp	deg F	60
Average Conditions warm Temp	deg F	82
Tank Diameter	ft	105
Exposed Sidewall Depth	ft	34.5
Buried Sidewall Depth	ft	0
Floor slope	ft/ft	0.167
Center Depth	ft	8.7675
Total Wall Area (per tank)	sq.ft	11,380
Total buried wall area (per tank)	sq.ft	0
Total Floor Area (per tank)	sq.ft	17,558
Total Roof Area (per tank)	sq.ft	17,318

Conditions at MMDW

Cold months		**Digester Tanks 6&7**
No of tanks		2
Wall losses per tank	Btu/hr	384,089
Floor losses per tank	Btu/hr	164,605
Roof Losses per tank	Btu/hr	324,713
Total losses per tank	Btu/hr	873,407
Total losses	Btu/hr	1,746,814

Warm months

No of tanks		2
Wall losses per tank	Btu/hr	158,757
Floor losses per tank	Btu/hr	68,037

Roof Losses per tank	**Btu/hr**	**134,215**
Total losses per tank	**Btu/hr**	**361,008**
Total losses	**Btu/hr**	**722,017**

Average conditions

Cold months

No of tanks		2
Wall losses per tank	**Btu/hr**	**384,089**
Floor losses per tank	**Btu/hr**	**164,605**
Roof Losses per tank	**Btu/hr**	**324,713**
Total losses per tank	**Btu/hr**	**873,407**
Total losses	**Btu/hr**	**1,746,814**

Warm months

No of tanks		2
Wall losses per tank	**Btu/hr**	**158,757**
Floor losses per tank	**Btu/hr**	**68,037**
Roof Losses per tank	**Btu/hr**	**134,215**
Total losses per tank	**Btu/hr**	**361,008**
Total losses	**Btu/hr**	**722,017**

Total Tank Losses (all digesters)		**Average Conditions**
Winter Months	**Btu/hr**	**3,759,827**
Warm Months	**Btu/hr**	**1,554,062**

Total Heat requirements

Total Heat Req'd (cold mnth):	**Btu/hr**	**7,981,952**
Total Heat Req'd (warm mnth):	**Btu/hr**	**4,274,987**

Table B-2
Line Item Capital Costs for Each Alternative

Feasibility Level Capital Costs of Alternatives										
Item	Cost	Cost Unit	Alternative 1		Alternative 3		Alternative 5		Alternative 5a	
			Qty.	Cost	Qty.	Cost	Qty.	Cost	Qty.	Cost
Engine Packages (w/ exhaust HEX)	$ 1,092,000	EA	3	$ 3,276,000	0	$ -	0	$ -	0	$ -
Engine Packages (direct exhaust use)	$ 882,000	EA	0	$ -	3	$ 2,646,000	0	$ -	0	$ -
Gas Conditioning (fueling engines)	$ 1,500,000	LS	1	$ 1,500,000	1	$ 1,500,000	0	$ -	0	$ -
Gas Coniditioning (fueling dryer)	$ -	LS	0	$ -	0	$ -	1	$ -	1	$ -
Gas Compressors/Assoc. Equipment	$ 350,000	LS	0	$ -	1	$ 350,000	1	$ 350,000	1	$ 350,000
Existing Engine Demolition	$ 180,000	LS	1	$ 180,000	1	$ 180,000	1	$ 180,000	1	$ 180,000
Biogas Piping	$ 95	LF	150	$ 14,250	3500	$ 332,500	3500	$ 332,500	3500	$ 332,500
Waste Heat (water) Piping	$ 350	LF	100	$ 35,000	4500	$ 1,575,000	4500	$ 1,575,000	0	$ -
New Heat Exchanger for Sludge Heating	$ 250,000	LS	0	$ -	0	$ -	1	$ 250,000	0	$ -
Pumps for waste heat water line	$ 175,000	LS	0	$ -	1	$ 175,000	1	$ 175,000	0	$ -
Exahaust Pipeline	$ 300	LF	0	$ -	150	$ 45,000	0	$ -	0	$ -
Natural Gas Pipeline Extension	$ 90	LF	300	$ 27,000	900	$ 81,000	700	$ 63,000	700	$ 63,000
TECO Engine Demolition	$ 70,000	LS	0	$ -	1	$ 70,000	0	$ -	0	$ -
TECO Building Retro-fit	$ 225,000	LS	0	$ -	1	$ 225,000	0	$ -	0	$ -
Electrical & Instrumentation	15%	%		$ 716,400		$ 700,650		$ 78,750		$ 52,500
Subtotal				**$ 5,748,650**		**$ 7,880,150**		**$ 3,004,250**		**$ 978,000**
Engineering & Administration	20%	%		$ 1,149,730		$ 1,576,030		$ 600,850		$ 195,600
Contingency	30%	%		$ 1,724,595		$ 2,364,045		$ 901,275		$ 293,400
Total				**$ 8,622,975**		**$ 11,820,225**		**$ 4,506,375**		**$ 1,467,000**

Table B-3
Line Item O&M Costs for Each Alternative

Annual Operation and Maintenance Costs FY2012

Natural Gas Cost	$ 4.50	$/MMBTU
Electricity Costs	$ 0.09	$/kWh
Digester heating needs	46,872	MMBTU/YR
Digester Biogas Production	22.8	MMBTU/hr
CHP Heat Recovery value	9.8	MMBTU/hr
Dryer Heat Recovery Value	10.0	MMBTU/hr
New Engine Efficiency	38%	
Engine Run Time	85%	

Item	Alternative 1	Alternative 3	Alternative 5	Alternative 5a	Alternative 7	Current	Notes/Comments
Engines							
-Parts/Materials	$ 49,140	$ 49,140	$ -	$ -	$ -	see note (2)	1.5 % of engine costs
- Labor	$ 90,480	$ 90,480	$ -	$ -	$ -	$ 180,960	50% of current maintenance labor for new engines
Gas Conditioning							
-Parts/Materials	$ 50,000	$ 50,000	$ -	$ -	$ -	see note (2)	
- Labor	see note (1)	see note (1)	$ -	$ -	$ -	see note (1)	
Compressors							
-Parts/Materials	$ 5,000	$ 10,000	$ 10,000	$ 10,000	$ 5,000	see note (2)	
- Labor	see note (1)	see note (1)	$ 30,000	$ 30,000	$ 15,000	see note (1)	
Boilers							
-Parts/Materials	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	see note (2)	
- Labor	see note (1)	see note (1)	$ 15,000	$ 15,000	$ 15,000	see note (1)	
Permitting							
- Air permiting/emmisions testing	$ 27,000	$ 27,000	$ -	$ -	$ -	$ 27,000	
Natural Gas Use							
- Miscellaneous	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	digester upset, engine maintenance etc.
Operations Cost							
-Operations Labor (1)	$ 299,592	$ 299,592	$ 45,000	$ 45,000	$ 30,000	$ 299,592	Current system value was provided by the City (1), (3)
Total O&M Costs							
-Parts/Materials/Permitting	$ 161,140	$ 166,140	$ 40,000	$ 40,000	$ 35,000	$ 322,000	
-Labor Costs	$ 390,072	$ 390,072	$ 45,000	$ 45,000	$ 30,000	$ 480,552	Current system value was provided by the City (3)
Generated Revenues							
- Power Generation	$ (1,701,508)	$ (1,701,508)	$ -	$ -	$ -	$ (927,000)	
- Digester Heating Offset	$ (210,924)	$ (210,924)	$ (210,924)	$ (210,924)	$ (210,924)	$ (210,924)	
- Natural Gas Offset in Dryer	$ -	$ (309,053)	$ (962,341)	$ (687,852)	$ -	$ -	
Net O&M with Dryer	**$ (1,361,220)**	**$ (1,665,273)**	**$ (1,088,265)**	**$ (813,776)**	**$ (145,924)**	**$ (335,372)**	
Net O&M without Dryer	**$ (1,361,220)**	**$ (1,356,220)**	**$ (125,924)**	**$ (125,924)**	**$ (145,924)**	**$ (335,372)**	

Notes:

All values are for the first operational year of each alternative

(1) Labor costs associated with gas conditioning, compressors, and boilers are included in the operations labor cost as provided by the City. The values for Alternative 1 and 3 are equal to that of the current system because the operation of these systems is similar.

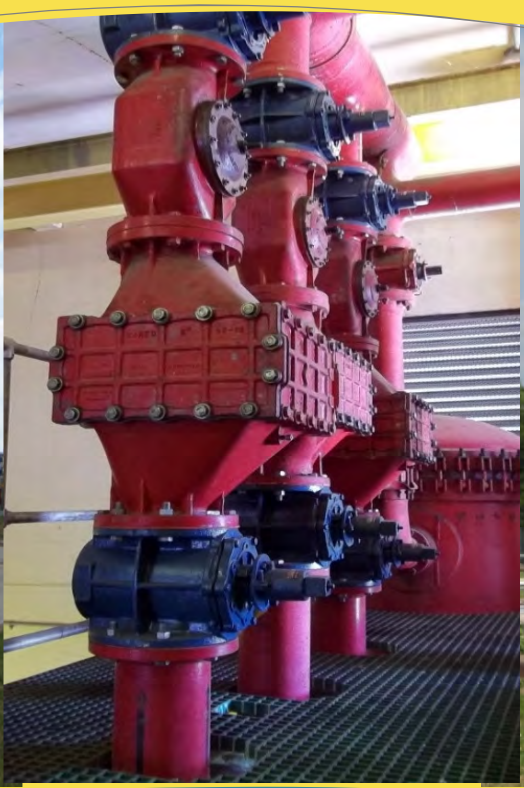
(2) Parts/Materials costs were provided as a total amount by the City. This total includes parts/materials for each of the categories listed above

(3) See Table B-4 in Appendix B

Table B-4
Current System O&M Costs

Current Co-Gen Analysis FY2012			
Labor Information			
Number of Mechanics	4	Maintenance labor	
Full time equivalent pay rate	$43.50		
Time spent on Co-Gen	50%	50% at other facilities	
Total Annual Hours	2,080	40 hour work week	
Number of Operators	1	Operations labor	
Full time equivalent pay rate	$42.75	$28.50 plus 50% for fringes	
Ops Time spent on Co-Gen	80%	20% at other facilities	
Total Annual Hours	8,760	365 days per year, 24 hrs/day	
Labor Costs			
Maintenance Labor			$180,960
Operations Labor			$299,592
Parts/Material Cost			
Parts Budget (2)			$180,000
Oil(3)			$95,000
Permitting & Air Emissions Testing			$27,000
Total Annual O&M Cost			**782,552**
Revenue from energy production			
Average Electricity Benefit 2009-2011 (4)			($927,000)
Offset of Natural Gas Needed for Digesters			($210,924)
Total Annual Net O&M and Revenue for Current Co-Gen			**$ (355,372)**
Notes:			
Does not include costs for compressors and other peripheral equipment			
(1) All O&M cost information provided by the City			
(2) Based on FY2012 Budget			
(3) Based on FY2012 Purchase Order			
(4) Based on average energy production calculated from data provided by City			

MWH



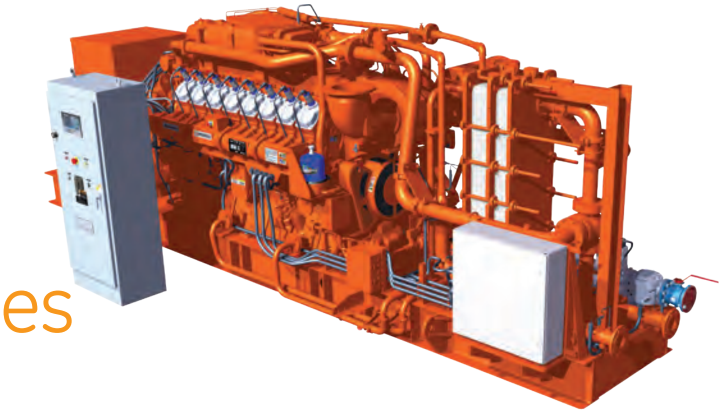
Howard F. Curren AWTP

Biogas Use Study

JUNE 2013

APPENDIX C

GE Energy



Waukesha* gas engines

APG1000

APG* Gas Enginator* Generating System
1000 kWe @ 50 Hz/1100 kWe @ 60 Hz

CHP

The APG1000 Combined Heat and Power (CHP) package allows for optimized efficiency by maximizing heat recovery. This minimizes packaging cost and time by including CHP components factory mounted. Achieve up to **89.4%** total efficiency with the APG1000 CHP package.

With a reputation for rugged durability and ongoing design advancements, Waukesha engines are the sound investment you can depend on in mission-critical applications. Now a part of GE Energy, Waukesha provides enhanced support in the form of parts, service and a network of distributors to make us an even stronger partner for today's global energy industry.

reference installations

model, site	key technical data	description
APG1000 **Sicily, Italy**	Fuel........Natural gas Engine type........APG1000 Electrical output........1000 kWe Thermal output........1100 kW Commissioning........1st Quarter 2012	A Hospital in Catania, Sicily, Italy is installing the Waukesha APG1000 CHP package. Hospitals have a high heat load making CHP a perfect fit to maximize energy efficiency and cost savings. 
APG1000 **Seika Teisyo, China**	Fuel........Sewage gas (WWTP) Engine type........APG1000 Electrical output........900 kWe Thermal output........1100 kW Commissioning........1st Quarter 2012	The Seikai Teisyo Project is located in mainland China. JFE Engineering Corporation is installing Waukesha CHP package at a new wastewater treatment plant. The customers needed to maximize heat production for the treatment process which made the APG1000 the optimum decision. 

imagination at work

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* Trademark of General Electric Company

technical features

feature	description	advantages
Factory built CHP package	Oil and water circuits optimized for maximum thermal efficiency	-Hot water return temperature of up to 80°C (176°F) suitable for many applications -Wide range of customer side flow rates are permissible
Electric jacket water pump and temperature control valve	Engine side coolant circuit flow is controlled by genset mounted pump	-Fast engine warm-up is possible -Post shutdown cooling is possible
ECP8000E genset control panel included	Full featured CHP control panel is provided with simple hook-up to genset mounted junction box	-Customer configurable spare I/O is provided to control ancillary equipment -Connect to genset with a simple Ethernet cable -Monitor the CHP system remotely

technical data

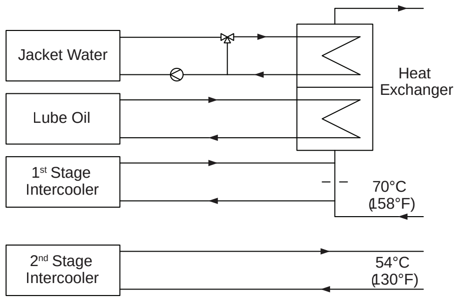
Engine	Waukesha 16V150LTD, Four Cycle, Lean Burn
Cylinders	V16
Piston displacement	48L (2924 cu. in.)
Bore & stroke	152 x 165 mm (5.98" x 6.5")
Jacket water system capacity	159L (42 gal.)
Auxiliary water capacity	30 L (8 gal.)
Lube oil capacity	820 L (215 gal.)
Starting system	24VDC Electric
Dry weight	13,730 kg (30,200 lb.)

Dimensions l x w x h mm (inch)

CHP Package	7165 (282) x 1926 (76) x 2263 (89)

Weights kg (lb)

CHP Package	14900 (32800)



performance data

Natural gas

NOx	Cooling system configuration	Pel (kW) 1,800 rpm/60 Hz	ηel (%)	Pth (kW)	ηth (%)	ηtot (%)	Pel (kW) 1,500 rpm/50 Hz	ηel (%)	Pth (kW)	ηth (%)	ηtot (%)
"TA Luft NOx 1.0 g/bhp.hr"	Standard	1,100	41.7	1,053	39.9	81.6	1,000	42.1	905	38.0	80.1
	CHP	1,100	41.7	1,260	47.7	89.4	1,000	42.1	1,067	44.9	87.0
"1/2 TA Luft NOx 0.5 g/bhp.hr"	Standard	—	—	—	—	—	1,000	40.8	976	39.9	80.7
	CHP	—	—	—	—	—	1,000	40.8	1,132	46.3	87.1
0.6 g/bhp.hr	Standard	1,100	40.8	1,095	40.6	81.4	—	—	—	—	—
	CHP	1,100	40.8	1,300	48.3	89.1	—	—	—	—	—
Biogas											
"TA Luft NOx 1.0 g/bhp.hr"	Standard	1,100	40.9	995	37.0	77.9	1,000	42.0	835	35.0	77.0
	CHP	1,100	40.9	1,192	44.3	85.2	1,000	42.0	1,005	42.1	84.1

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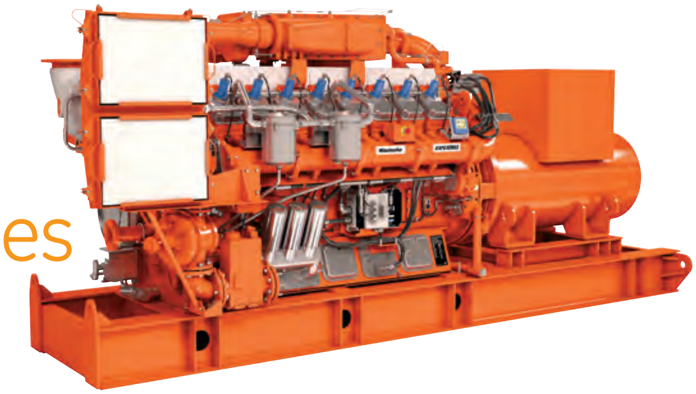
GE Energy



Waukesha* gas engines

APG1000

APG* Gas Enginator* Generating System

1000 kWe @ 50 Hz/1100 kWe @ 60 Hz

biogas

Because of its flexible design and the powerful ESM interface, the APG1000 is extremely tolerant of fuel changes, and is capable of operating on fuel from 15.73-25.56 MJ/Nm^3 (400 – 650 BTU) with little or no manual recalibration or adjustment during BTU variation. This means the Waukesha APG1000 brings power generation to a wide range of biogas applications including:

- Waste water treatment plants
- Farm waste digesters
- Animal waste farms
- Municipal and private landfills

With a reputation for rugged durability and ongoing design advancements, Waukesha engines are the sound investment you can depend on in mission-critical applications. Now a part of GE Energy, Waukesha provides enhanced support in the form of parts, service and a network of distributors to make us an even stronger partner for today's global energy industry.

reference installations

model, site	key technical data	description	
APG1000 **Auckland, New Zealand**	Fuel .... Landfill gas Engine type .... 4 x APG1000 Electrical output .... 4000 kWe Thermal output .... NA Commissioning 2009/2010	Four APG1000 Generators in operation, two commissioned in 2009 and two commissioned in 2010. The site covers an area of approximately 87 hectares and has a final design capacity of approximately 36 million tons of waste. With landfilling operation expected to continue up until 2050, the Hampton Downs Landfill will play a key part in Auckland's waste solutions for many years to come.	
APG1000 **South Manila, Philippines**	Fuel .... Landfill gas Engine type .... 1 x APG1000 Electrical output .... 1000 kWe Thermal output .... 1053 kW Commissioning 2009	Located about 60 km (40 miles) south of Manila, Cavite Pig City Inc. (CPC) is an advanced facility with a population of 100,000 pigs and a commitment to environmental responsibility. The largest single biogas power plant in The Philippines, it generates electricity, and captures the engine's waste heat for use in other essential farm operations.	

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* Trademark of General Electric Company

technical features

feature	description	advantages
Fuel Control	Specific fuel control system for biogas fuels optimized to handle changing fuel quality on landfill gas, wastewater treatment plant digester gas, and animal farm waste digester gas with heating values of 15.73-25.56 MJ/Nm^3 (400 – 650 BTU)	Application flexibility, minimal manual intervention, increased uptime/availability, maximizes return on investment
Packaging	Overall engine/genset envelop supports containerization	Ability to create a compact and portable genset solution
Efficiency	Optimized combustion, low flow loss engine breathing, Miller Cycle combustion, specific turbocharger matching and high efficiency generators	Higher electrical efficiency maximizes return on investment

technical data

Engine	Waukesha 16V150LTD, Four Cycle, Lean Burn
Cylinders	V16
Piston displacement	48L (2924 cu. in.)
Bore & stroke	152 x 165 mm (5.98" x 6.5")
Jacket water system capacity	159L (42 gal.)
Auxiliary water capacity	30 L (8 gal.)
Lube oil capacity	820 L (215 gal.)
Starting system	24VDC Electric
Dry weight	13,730 kg (30,200 lb.)

Dimensions l x w x h mm (inch)

Water Connection	5105 (201) x 2143 (94) x 2215 (87)
Heat Exchanger	5821 (229) x 2160 (85) x 2215 (87)

Weights kg (lb)

Water Connection	13727 (30200)
Heat Exchanger	14182 (31200)

performance data

Natural gas

		1,800 rpm/60 Hz					1,500 rpm/50 Hz				
NOx	Cooling system configuration	Pel (kW)	ηel (%)	Pth (kW)	ηth (%)	ηtot (%)	Pel (kW)	ηel (%)	Pth (kW)	ηth (%)	ηtot (%)
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	CHP	1,100	40.8	1,300	48.3	89.1	—	—	—	—	—
Biogas											
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ROBINSON

GROUP, LLC

Howard F Curren AWTP,
Tampa, FL

BUDGETARY PROPOSAL

March 18, 2013

BioGas Powered Energy Solutions

ROBINSON GROUP LLC
10316 NE 185th Street
BOTHELL, WA 98011

EMAIL: INFO@ROBINSON-GROUP.COM
FAX: (425) 491-7740

March 18, 2013

MWH Global
1000 N. Ashley St. Suite 1000
Tampa, FL 33602

Confidential Budgetary Proposal

Reference: Howard F. Curren AWTP, Tampa, Florida

Matt:

We are pleased to provide our budgetary proposal for a Robinson Group (RG) gas conditioning system. The **SulfrPack ST™ Sulfur Removal System** and **SAGPack™ Gas Conditioning System** proposed below will successfully deliver a turnkey solution to provide gas conditioning equipment for you're a gas flow rate of 695 scfm to fuel 3 Waukesha APG-1000 gen-sets.

In addition, RG can offer a Ten Year Gas Quality Guarantee with a signed Service Agreement. The Guarantee of Performance is important because the gas will change over time. These changes need to be tested and monitored correctly by a supplier with extensive experience in biogas process. With these changes, the RG Provided Digester Gas Conditioning System can be internally changed to accommodate the expected changes with the incoming gas. Operators and municipalities have come to rely on this partnership approach of gas quality maintenance by the Robinson Group, LLC.

The following pricing, exclusive of **taxes** is proposed:

Item Description	Price
SulfrPack ST™ Sulfur Removal System and SAGPack™ Gas Conditioning System	**USD $983,900**

Advantages of Robinson Group Systems & Support

Robinson Group can offer the following guarantees and experience:

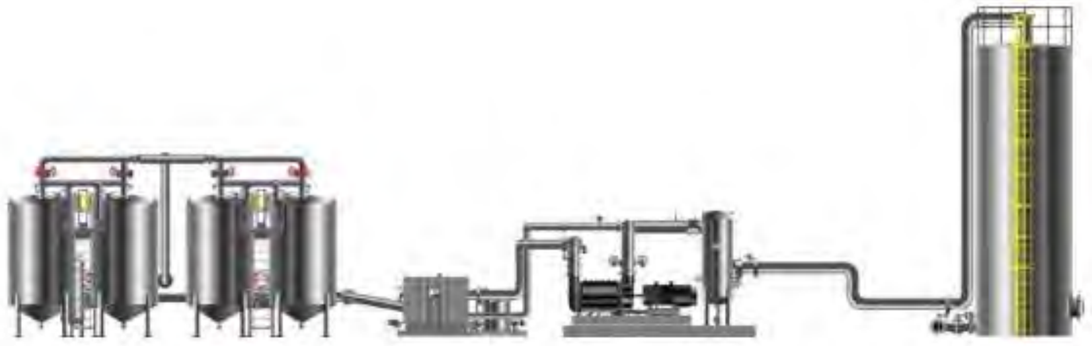
1. 10 Year Gas Quality Guarantee with Long Term Service Agreement
2. 18 month warranty from equipment delivery
3. Pre-assembled and skid mounted packages for easy installation
4. Full system remote monitoring available
5. RG system support available
6. Next day full gas analysis at the RG Seattle Lab
7. System pressure relief provided
8. Ability to design an integrated, turn-key gas conditioning system
9. Our experience includes over 150 projects in North America on digester gas to energy
10. 15 years of work in biogas processing, the longest of any company

Robinson Group Experience in Biogas Conditioning

Robinson Group is an expert at helping clients identify and eliminate biogas contaminants and capitalize on their waste streams. Robinson Group has custom-designed, installed, fine-tuned and operated biogas-to-energy systems for hundreds of manufacturers, consultants, municipalities, and energy companies so they can generate clean energy and achieve a stronger bottom line.

RG is the biogas conditioning industry’s most experienced firm, with hundreds of installations from California to Taiwan. RG designs, builds and operates over 150 SAGPack™, SAG vessels and media, and SulfrPack™ biogas systems worldwide. Each system is fully guaranteed and supported by RG.

In our drive to find better ways to eliminate machine-clogging contaminants from waste streams, we have built up an industry-leading number of patents (four, with seven in review). As we move forward, we will continue to engineer biogas conditioning solutions that meet our customers’ needs and bottom lines.



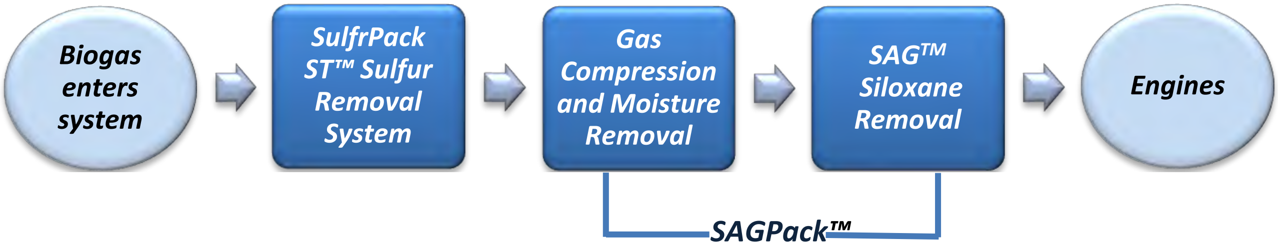
Proposed Process Description

The biogas will go through two major stages before it exits the gas conditioning system. First, the gas enters the **SulfrPack ST™** Sulfur Removal System to remove the sulfur. After the gas is treated for H_2S, saturated gas enters the **SAGPack™** gas conditioning system.

In the 2nd major stage, the gas enters the **SAGPack™**, which consists of gas compression and moisture removal system, and SAG™ siloxane removal system. The gas will first goes into the gas compression. It then goes through two heat exchangers. The first heat exchanger (gas/gas) will use the hot gas from compression to reheat the cold gas from the second heat exchanger (gas/glycol) which uses chilled glycol to cool the gas to 40^0F. After the gas is chilled, it goes through a water knock-out separator before entering the opposite side of the first heat exchanger to be reheated to 80^0F.

Finally, the gas moves through the SAG™ siloxane removal system where all different species of siloxane are removed to desired level of concentration. The gas passes through a final particulate filter before it is sent to Engines for power generation.

Process Flow Chart



Equipment Description

SulfrPack ST™ Sulfur Removal System

SulfrPack™ ST is a biogas treatment system that removes sulfur from waste streams at a range of 0-2,000 ppm. SulfrPack™ ST is also equipped with a highly-effective odor control system that neutralizes sulfur and light mercaptan-type odors from any air or gas stream. This high-capacity product's reliability in partially to fully humid air makes it unique to other sulfur removal systems.

Gas Compression & Moisture Removal System

The Gas Compression & Moisture Removal System consists of a complete blower and moisture removal package. Included in the blower and moisture removal package are blowers, piping, relief valve, instrumentation, heat exchangers, chiller and condensate knock-out pot.

SAG™ Siloxane Removal System

The SAG system is designed to remove siloxanes from biogas. It includes patented technology for stratifying the media and calibration of the siloxane removal capabilities of the system based on the different species identified during gas testing. System size is based on gas velocity, temperature, pressure, and SIL-2 gas analysis.

SAG™ removes hundreds of different organic and siloxane species, as well as non-methane VOCs and halides. The system includes one or more vessels that use special media and patented polymorphous porous graphite.

RG has developed over 270 SAG media combinations that can be used to target the different species of VOC< and siloxane. This system has defined siloxane removal in our industry, and it is the most cost-effective solution for small to mid-sized installations, for any flow rate.

Design Conditions

This customized proposal is based on the following biogas characteristics including Inlet Conditions, Outlet Conditions and System requirements and/or end use of gas.

Inlet Conditions:

Composition	
Methane	50 to 60 percent
Carbon Dioxide	35 to 45 percent
Oxygen	0 to 3 percent
Nitrogen	1 to 10 percent
Hydrogen Sulfide	< 200 ppmv
Siloxane	1.2 to 1.5 ppmv (average)
Moisture	Saturated
Pressure	2-10" W.C.
Gas Flow (dry)	695 SCFM
Inlet Temperature	90-100 F

Outlet Conditions:

Temperature	80 F
Total Siloxanes/Organosilicones	<100 ppbv total
Hydrogen Sulfide	< 20 ppmv
Moisture	< 40% RH
Outlet Gas Pressure	$\geq$ 4 psig

System requirements and/or end use of gas

Intended use of treated gas	Customer Supplied Waukesha APG-1000 engines.

Proposed Equipment

SulfrPack ST™ H_2S Removal System

Vessel Information	
Number of Vessels:	1 (one)
Configuration:	Single vessel
Media Bed Depth:	7 ft.
Diameter (ID):	12 ft.
S/S Height:	10 ft.

Vessel Construction	
Construction/Material:	304 Stainless Steel
Tank ladders and platforms:	Included on each vessel
Top and side man ways:	Included on each vessel

Media	
Media type:	SulfraTreat EST2242
Media change-out time:	18 months
Media:	48,000 lbs.
Media fill:	Start-up fill of media is included

RG will provide one **SulfrPack ST™** vessel and platform to be shipped loose to the job site for installation on concrete pads provided by others.

Compression, moisture removal and cooling

Equipment	Name/ Size / Power/Description
Blower:	Two (2) 40 HP Blower (100% redundant)
Cooling:	One (1) 40 ton chiller
Heat Exchanger:	One (1) dual core heat exchanger with internal moisture removal
Particulate matter removal:	< 99% of 3 micron or larger at max flow; Inlet & outlet filters
Control panel	Allen-Bradley PLC Control Panel
Skid:	Coated carbon steel
Comments:	SAGPack skid is Class 1, Division 1. Chiller skid is non-classified. Chiller skid must be located 10 ft from SAGPack skid.

RG will provide the gas compression and heat exchanger skid fully assembled and tested in our factory prior to delivery to be installed on a concrete pad provided by others. Electrical control panel will be shipped loose and must be located in a nonhazardous area. The chiller will be shipped preassembled and must be located in a nonhazardous area. All interconnecting piping and wiring is by others.

SAG Siloxane Removal System

Vessel Information	
Number of Vessels:	Two (2)
Configuration:	Lead/Lag
Media Bed Depth:	8 ft.
Diameter (ID):	5 ft.
S/S Height:	10 ft.

Vessel Construction	
Construction/Material:	304 Stainless steel
Code Rating:	Rated for 15 psig
Tank ladders and platforms:	Included on each pair of vessels

Media	
Media change-out time:	16 months per lead vessel
Media:	4,400 lbs / vessel
Media type:	SAG/HOX
Media Fill:	Start-up fill of media is included

RG will provide two pre-assembled **SAG™** vessels, platforms, and pre-fit piping to be shipped loose to the job site for installation on concrete pads provided by others.

Additional Comments & Exclusions

Overall system

All gas processing skids will be considered a Class I, Division 1 Group D unless otherwise noted.
Gas quality guarantee is only valid with a RG service agreement
Control Panel, BioStrip Housing, and Chiller are non-classified.

Electrical System

- 120VAC 1 phase and 480VAC 3 phase power will be required to main control panel.
- 120VAC and 480VAC power from control panel to BioStrip controls house
- 120VAC and 24VDC power from control panel to gas compression skid
- 480VAC power to chiller and gas blowers

Service and Equipment not provided by RG

Contractor other than RG shall be responsible for:

- Site assembly of equipment piping (other than on skid)
- Freeze protection (Heat-trace, insulation)
- Filling all electrical seals on the skid if applicable
- Any conduits entering or leaving the classified area
- Installing interconnecting pipe connecting the vessels
- Performing all media loading
- Any and all associated permits are not included in this proposal
- Foundations, anchors and supports

Delivery, Schedule & Submittals

- Submittals provided within 4-6 week after receipt of an executed contract by all parties.
- All gas conditioning equipment will be delivered within 20-22 weeks after receipt of written approval of the submitted shop drawings.
- Installation Manuals will be furnished per contract specifications.
- Operation and Maintenance Manuals will be submitted within 30 days after delivery of all equipment.

Installation & Operation

- All free standing vessels will be shipped loose for field installation by installation contractor.
- RG field services shall be provided for start-up and training on site. The start-up services, along with site training will be provided during one site visit of five (5) consecutive days, total. RG field services shall be limited to observation and RG comments upon the

installation of the RG system. RG shall not instruct, guide and/or direct the CONTRACTOR’s erection and installation procedures.

Terms of Payment

Please note that the above pricing is expressly contingent upon the items in this proposal.

The price is FOB shipping points, with freight allowed to the job site. This price does not include any sales or use taxes of any kind.

The terms of Payment are as follows:

- 15% of project value at submittal approval.
- 25% of project value at release to manufacture.
- 25% of project value at mid-point Construction which can be defined as the mid-point between release to manufacture and delivery.
- 25% of project value at Delivery.
- 10% of project value Final Acceptance not to exceed 30 days from equipment delivery or 30 days RG’s notification of readiness to ship, whichever occurs first.
- Note: Payment shall not be contingent upon receipt of funds by the Contractor from the Owner. There shall be no retention in payments due to RG. All Payment terms are Net 30 days from the date of invoice.

Price Escalation: Please note that due to the volatile metal and fuel markets, prices are subject to confirmation at the time of procurement if PO is received after the quote expiration date. In addition, pricing is contingent upon customer taking delivery of equipment within 9 months of issuance of Purchase Order to RG. This quotation will remain valid for sixty (60) days.

Contact Information

Thank you for your interest in Robinson Group. Should you have any additional questions, please contact:

RG’s Regional Sales Manager, Joe Yelpo, 908.930.5322