Biosolids Energy and Emissions Plan

Executive Summary

The Encina Wastewater Authority (EWA) has undertaken a Biosolids Energy and Emissions (BEE) Plan that will be used to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed Process Master Plan. The BEE Plan has several goals:

- Provide a comprehensive analysis of all project elements including biosolids treatment, biogas use, energy generation, and waste heat
- Address capacity limitations in the solids handling process at the Encina Water Pollution Control Facility (EWPCF)
- Assess which alternative is likely to be the most cost-effective and sustainable solution for EWA
- Move EWPCF toward lower energy costs, rate stability, and greater overall sustainability
- Reduce greenhouse gas emissions

As part of the BEE Plan, the Brown and Caldwell (BC) team performed an extensive technology and alternatives analysis which is documented in a series of eight technical memoranda. Major decisions were made, including technology selection and narrowing of alternatives, in a series of workshops with EWA staff. Table ES-1 includes a list of these ten technical memoranda.

Table ES-1. Summary of BEE Technical Memoranda	
TM 1	Baseline Energy Profiles and Projections
TM 2	Technology Evaluations for Biosolids Handling
TM 3	Technology Evaluations for Alternative Power Production
TM 4	Technology Evaluations for Biogas Production
TM 5	Technology Evaluations for Waste Heat
TM 6	Air Emissions
TM 7	Alternatives Development, Evaluation, and Selection
TM 8	Grant Incentive Programs Summary
TM 9	High Strength Waste Feasibility Study
TM 9.1	Encina Renewable Natural-gas Injection Feasibility Study

BEE Process

The process began with an evaluation and selection of technologies for solids processing and energy generation. The technologies selected are presented in Table ES-2. These technologies were subjected to a fatal flaw screening process and evaluated for the following fatal flaw criteria:

- There must be at least one full-scale installation of the technology at a wastewater treatment plant (WWTP) in North America

- There must be at least one successful installation of the technology at a facility of similar size to EWPCF to ensure compatibility
- The technology must be accommodated within EWPCF's limited available footprint
- The technology must be capable of being integrated into the existing treatment infra-structure

If a given technology failed any of the fatal flaw criteria, it did not proceed to the next round of evaluation.

Table ES-2. Evaluation and Selection of Technologies for Solids Processing and Energy and Heath Utilization

Solids Processing Technologies				Energy and Heat Utilization		
Thickening	Stabilization	Dewatering	Post Digestion	Biogas Treatment	Energy Generation	Waste Heat Utilization
Primary clarifier	Mesophilic anaerobic digestion	Centrifuge	Direct drum drying	Biogas upgrading	Internal combustion engines	Small-scale steam turbines
Dissolved air floatation	Mesophilic high-solids digestion	Belt filter press	Indirect drying	Gas conditioning	Microturbines	Thermophilic digestion or thermal hydrolysis process
Rotary drum	Staged mesophilic anaerobic digestion	Screw press	Solar drying	Exhaust treatment	Direct use of biogas in drying	Adsorption and absorption chillers
	Acid-gas phase digestion	Rotary press	Gasification	WAS pretreatment	Fuel cells	Organic Rankine cycle
	Thermophilic anaerobic digestion	Volute press	Pyrolysis	Increased co-digestion	Energy storage (batteries)	Gasification of biosolids
	Temperature-phased anaerobic digestion	Bucher press	Incineration		Large-scale photovoltaics	
	Thermal hydrolysis process		Deep-well injection		Small-scale photovoltaics	
	Enzymatic hydrolysis		Dehydration		Wind turbines	
	Thermo-chemical hydrolysis				Direct sale to adjacent power plant	
	Lystek				Net energy metering	

Technologies in blue were considered in the end-to-end alternatives.

Following the fatal flaw evaluation, technologies were scored and ranked for a series of criteria developed with EWA. While some criteria overlap, unique criteria were developed for the solids and energy related technologies. Technologies were ranked on a scale of 1 to 5, with scoring performed in a workshop setting. Those with an aggregate score of under 3 were eliminated from further analysis. Those technologies that were used in the formation of end-to-end alternatives are presented in bold in Table ES-3; alternatives that are not presented in bold were eliminated from further consideration.

Table ES-3. End to End Technology Screening and Ranking

Criterion	Description	Scoring Description	Weight
Proven Technology Performance	Proven and reliable technology with same configuration intended at Encina. Long successful operating track record.	Low score indicates no successful large-scale operating installations in North America or Europe, no successful demonstration scale installations in North America or Europe, and unknown safety or reliability record. High score indicates more than one successful operating installation in North America or Europe, more than one operating installation at a WWTP of at least 40 mgd in North America or Europe, track record duration > 5 years, and vendors in western USA.	20%
Minimize Life-Cycle Costs	Qualitative metric of program cost. Capital and O&M costs based on existing EWA data or similar experience at other WWTPs. Potential revenues from sales.	Low score indicates high capital cost to build onsite facilities, high O&M costs, and low energy recovery efficiency. High score indicates low capital cost to build onsite facilities, low O&M costs, and potential revenue.	10%
Energy/Resource Recovery	Recovery of renewable energy.	Low score indicates high energy requirement for onsite technology, technology does not recover, and low efficiency recovery of renewable energy. High score indicates a higher electrical efficiency.	25%
O&M Impacts	Impacts to existing plant O&M staff levels. Complexity of new technology O&M and control systems. Reliability of new technology (potential downtime). Minimal impacts to plant safety.	Low score indicates more O&M time required, complex mechanical and control systems required compared with existing plant facilities, potential equipment downtime, and newer hazards. High score indicates reduction in O&M staff time required, new technology is simple to operate and maintain, reliable with minimal downtime, and no new hazards.	10%
Environmental Impacts	Impacts to carbon footprint and air permitting.	Low score indicates high carbon footprint for technology, and new permitting for environmental regulatory requirements. High score indicates low carbon footprint for technology, reduced pollutant emissions, no additional permitting for environmental regulatory requirements.	15%
Community & Stakeholder Impacts	Minimize nuisance impacts such as dust, odors, vectors, aesthetics, noise and traffic. Assess impacts to partner agency issues/values as well as local planning codes and requirements.	Low score indicates nuisance factors for on-site technology are difficult to mitigate. High score indicates nuisance factors can be mitigated at plant site.	10%
Project Site Compatibility	Assess compatibility of technology with available plant footprint. Incorporation into existing treatment process.	Low score indicates lack of site space for new facilities, requires abandonment of existing facilities, and difficult integration with existing plant. High score indicates available footprint for new facilities and maintains space for future facilities, ease of integration with existing processes and facilities.	10%

The BC team then worked with EWA to create over 48 end-to-end alternatives, which evaluated the solids process from thickening to final disposition, as well as assessing biogas treatment and beneficial use. Figure ES-1 shows how the technologies that passed the evaluation scoring criteria were combined to create end-to-end alternatives.

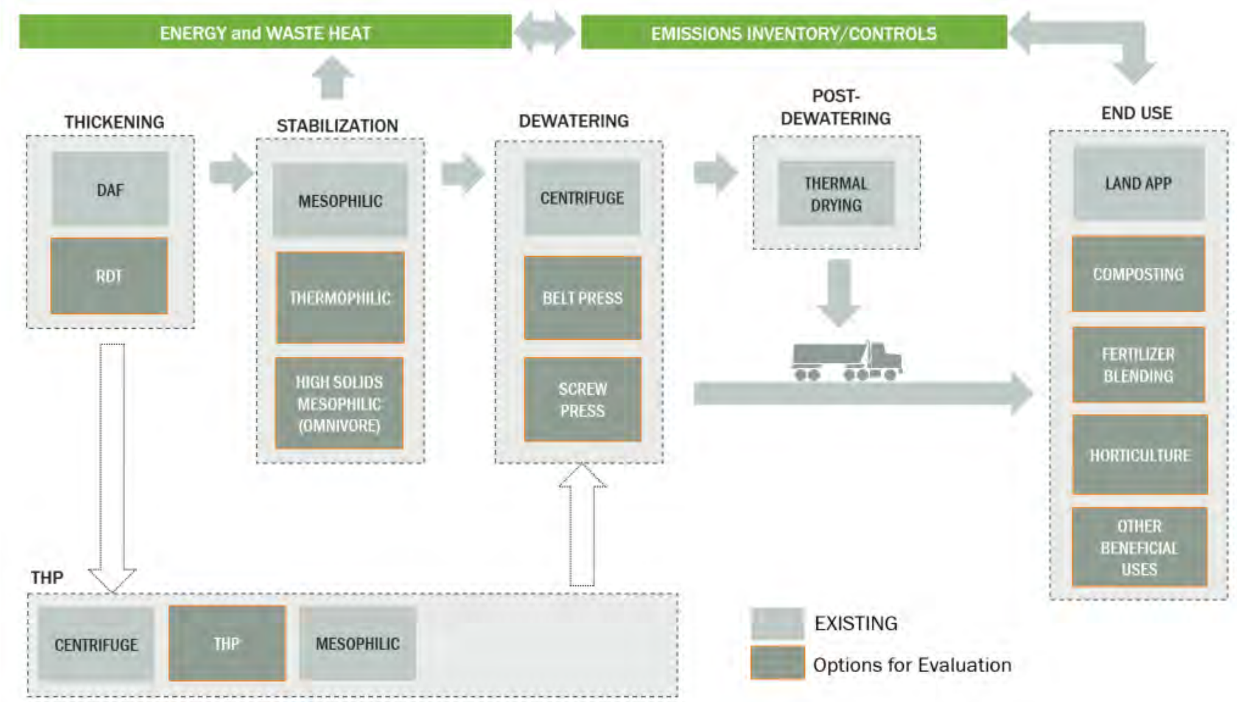

Figure ES-1. Technologies that passed evaluation scoring criteria combined to create end-to-end alternatives

Alternatives were developed for beneficial use of digester gas alongside solids handling improvements. The digester gas utilization alternatives included engine-based cogeneration systems, microturbine-based cogeneration systems, and gas separation to produce renewable natural gas (RNG) for pipeline injection. All technologies were evaluated across a range of DG production rates and various solids stabilization methods, which assumed various levels of co-digestion of organic high-strength waste (HSW). Alternatives were compared to a status quo alternative that assumed DG would be used to operate the existing cogeneration engines and solids dryer, with the remainder of gas flared when the dryer is down for maintenance. Solids handling alternatives included options to upgrade or enhance digestion capacity and final biosolids quality, including thermophilic digestion (Class B and Class A), thermal hydrolysis process (THP), and Omnivore, as well as mesophilic digestion, EWA's existing stabilization technologies. Nearly all solids processing alternatives were evaluated with both one or two dryer trains in service.

The top 5 end-to-end options evaluated are summarized in Figure ES-2. These alternatives were evaluated over two rounds of modeling and are represented on a net present value (NPV) basis.

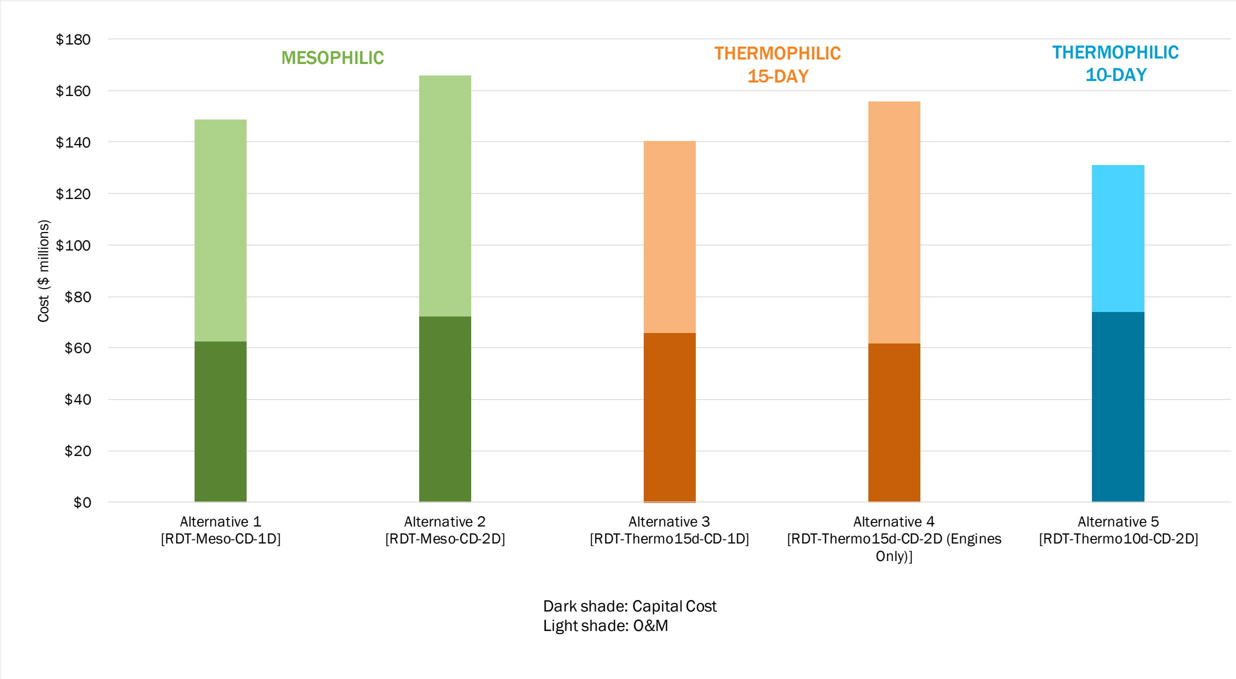

Figure ES-2. Overall NPV for top 5 alternatives

The top 5 end-to-end alternatives all have similar capital and NPV costs; therefore, cannot be screened based on economics alone. In addition, these alternatives have similar near-term project components such as digester improvements and RDTs for co-thickening. For all alternatives, long term projects should be selected based on meeting capacity, resiliency against changes, reducing odor, and reducing truck traffic at the plant.

Key Findings

Alternatives were ranked based on the 20-year NPV model results. The key findings of the analysis are listed below:

- All alternatives benefited from increased DG production from co-digestion of organic HSW.
- Improved thickening with rotary drum thickeners (RDT) provides multiple benefits and has reduced lifecycle costs compared to the existing thickening scheme.
- Thermophilic digestion allows for a higher loading potential of HSW for co-digestion; however, all solids alternatives are compatible with the existing engines or pipeline injection alternatives for DG utilization. There is currently no direct driver to upgrade to thermophilic.
- While the second dryer train does not perform as well on an NPV basis in nearly all alternatives, there are non-cost and practical reasons to implement a second train. The timing of bringing this second train on line to realize the most cost savings will be a very important decision for EWA.
- Upgraded DG for use as vehicle fuel, via pipeline injection, provides the greatest apparent NPV compared to cogeneration systems or in the solids dryer.
- Continued use and operation of the cogeneration system is recommended. Any measures that increase permitted cogeneration energy production or reduce the cost of electricity should be pursued. A net electric metering (NEM) tariff would reduce electric utility costs by eliminating the standby charge—it would also allow for power export and simplify (or eliminate) the EWPCF's

current grid isolation practice. Any air permit revisions to allow for greater DG utilization and energy output are recommended. The addition of upstream DG conditioning and exhaust treatment using a carbon monoxide (CO) catalyst appears to be the best pathway. Any changes that trigger more stringent exhaust treatment measures, such as selective catalytic reduction (SCR) or continuous emissions monitoring systems, should be avoided.

Implementation

Among the top performing alternatives, a series of near term (defined as 0 to 5 years) projects were common. These included digester improvements to address capacity issues, co-thickening improvements (RDTs), high strength waste receiving upgrades, and pipeline injection of biomethane. The BC team recommends that EWA address these near-term projects in its capital planning efforts. The majority of the mid-term (5-10 years from now) also had common elements, including dryer modifications, Class B biosolids truck loadout improvements, an Omnivore project, and centrifuge upgrades. The main differences between these options are that the mid-term projects address a mixture of aging equipment as well as desirable improvements to support high strength waste receiving and biosolids beneficial reuse while the near-term projects address immediate constraints and opportunities associated with the solids and energy processes at the EWPCF. Ultimately, the long-term (10 to 20 years) decisions are what distinguish the top performing alternatives and allow for full implementation of the recommended alternative, which includes a second dryer, an additional Omnivore project, and truck traffic improvements. These long-term projects will address the future increase in solids loadings to the EWPCF.

BC worked with EWA to develop a preferred alternative and discussed issues with associated phasing. Ultimately, addressing digester capacity early on in the program allows EWA to expand its co-digestion program and boost digester gas production. Timing on construction of the second dryer can be evaluated in further detail depending on the expansion of the co-digestion program and performance of thickening and digestion improvements with respect to solids reduction. Figure ES-3 shows an implementation schedule for the recommended alternative based on cost, resiliency, ability to meet plant capacity, and reducing truck traffic and odors.

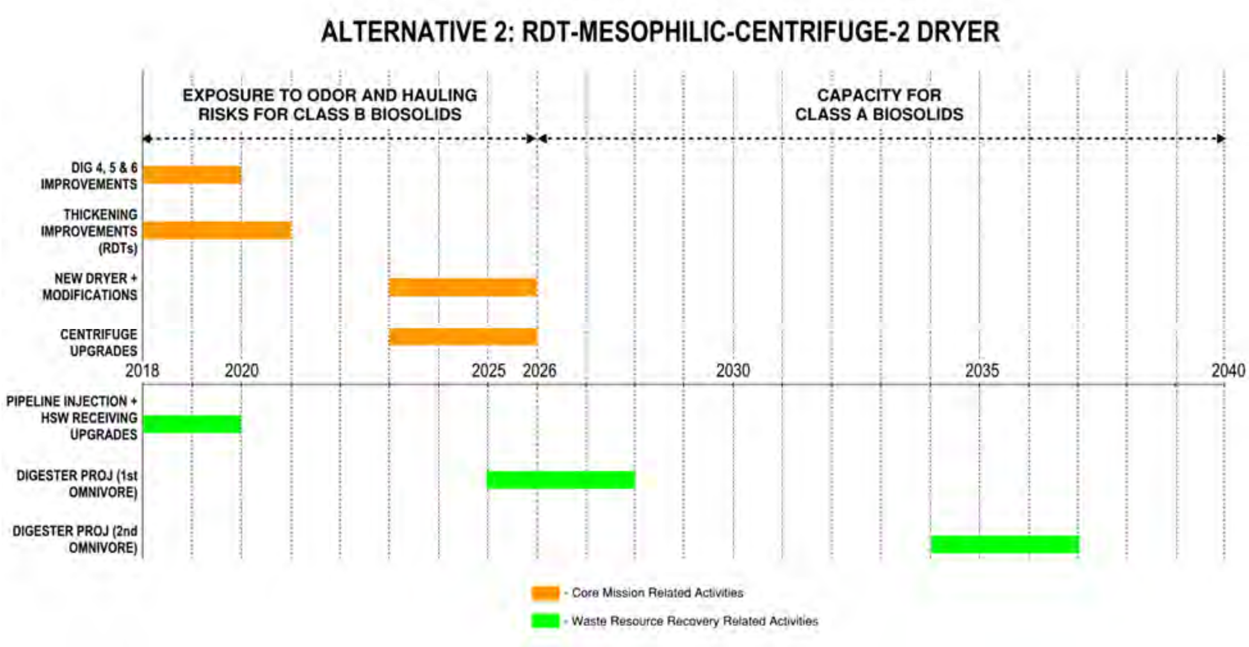

Figure ES-3. Implementation schedule for Alternative 2 (recommended alternative)

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Technical Memorandum

FINAL

Prepared for: Encina Wastewater Authority

Project Title: Biosolids, Energy and Emissions

Project No.: 150871.003.001

Technical Memorandum No. 1

Subject: Baseline Energy Profiles and Projections

Date: February 13, 2018

To: Scott McClelland, Assistant General Manager

From: Scott Lacy, P.E., Managing Engineer

Prepared by: ______________________
Natalie Sierra, P.E., Supervising Engineer
(C 69751 Exp. June 30, 2018)

Reviewed by: Perry Schafer
Perry Schafer, P.E., Vice President

Limitations:

This document was prepared solely for Encina Wastewater Authority in accordance with professional standards at the time the services were performed and in accordance with the contract between Encina Wastewater Authority and Brown and Caldwell dated June 28, 2017. This document is governed by the specific scope of work authorized by Encina Wastewater Authority; it is not intended to be relied upon by any other party except for regulatory authorities contemplated by the scope of work. We have relied on information or instructions provided by Encina Wastewater Authority and other parties and, unless otherwise expressly indicated, have made no independent investigation as to the validity, completeness, or accuracy of such information.

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List of Abbreviations

$/kWh	dollars per kilowatt hour
Btu	British thermal units
Btu/cf	British thermal units per cubic feet
BEE Plan	Biosolids Energy and Emissions Plan
CEPT	Chemically Enhanced Primary Treatment
DAF	dissolved air floatation
DGS	Department of General Services Natural Gas Program
dtpd	dry tons per day
EWA	Encina Water Authority
EWPCF	Encina
FOG	fats, oil, and grease
HHV	higher heating value
IC	internal combustion
kW	kilowatt
kWh	kilowatt hour
kWh/day	kilowatt hour(s) per day
lb/cf/d	pound(s) per cubic feet per day
lb/d	pound(s) per day
lb/hr	pound(s) per hour
lb/hr/sf	pound(s) per hour per square feet
lb-VS/(ft^3 d)	pounds volatile solids per cubic foot per day
MGD	million gallons per day
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
MMscf	million standard cubic feet
MWh	megawatt hour
NC	non-coincident
PMP	2016 Process Master Plan
ppd	pounds per day
PS	primary sludge
RTO	regenerative thermal oxidizer
scf	standard cubic feet
scf/lb-VS_d	standard cubic feet per pound volatile solids destroyed
scfm	standard cubic feet per minute
SDG&E	San Diego Gas and Electric
TM	Technical Memorandum
TOU	time of use
TS	total solids
TWAS	thickened waste activated sludge
VS	volatile solids
VSR	volatile solids reduction
WAS	waste activated sludge

Executive Summary

This Technical Memorandum (TM) 1 is the first of seven TMs comprising the Encina Wastewater Authority (EWA) Biosolids Energy and Emissions Plan. TM 1 serves to establish the baseline for planning by providing a summary of the current mass and energy balance for the Encina Water Pollution Control Facility (EWPCF), as well as a projection of future flows and loads. This data will be used in sizing and process related calculations in future tasks.

Tables ES-1 and ES-2 summarize EWPCF's major solids stream processes and their rated capacities for non-digestion and digestion processes, respectively. A mass balance was performed around the solids handling stream incorporating these processes; Figure ES-1 summarizes the results of this calibrated mass balance. All values in the figure describe averages over the 2-year period from May 2015 to June 2017 with loadings rounded to the nearest 100 pounds per day. All assumptions are documented in Section 2.2. This mass balance was reviewed by EWA staff in a workshop setting and subsequently finalized to incorporate additional EWA comments, data, and information. It must be noted that the mass balance was calibrated to agree with assumptions on process parameters and data that were deemed most representative. This was performed after a thorough review of the historic data and in consultation with EWA staff. For some parameters, EWA may wish to change the details of sampling to gain a better understanding and accuracy of those mass balance parameters.

Table ES-1. Major Non-Digestion Solids Stream Processes and Corresponding Capacities at EWPCF

Process	Technology	No. of Units		Capacity		Percent of Capacity Used		
		Total	Normal Service	Design Loading Rate[5]	Total Service Capacity	Average Annual Condition	Peak Month Condition[6]	Peak Day Condition[6]
Thickening	DAF	3	2	0.72 lb/hr/sf	90,000 lb/d[1]	33%[2]	40%	53%
Dewatering	Centrifuges	3	2	3,000 lb/hr	144,000 lb/d	26%[3]	32%	42%
Solids Drying	Thermal Dryer	1	1	30 dtpd	30 dtpd	60%[4]	74%	96%

[1] *Calculated assuming two 40-ft diameter DAF units in normal service.*

[2] *Calculated using average dry solids loading from calibrated mass balance (29,400 lb/d) to two 40-ft diameter service DAF units.*

[3] *Calculated using average dry solids loading from calibrated mass balance (38,700 lb/d) to service centrifuges.*

[4] *Calculated using average dry solids loading from calibrated mass balance (17.8 dtpd) to dryer.*

[5] *Thickening and dewatering capacities provided in the 2016 Process Master Plan. Dryer capacity provided by vendor.*

[6] *Peaking conditions were applied using the peaking factors developed in section 4.6.*

DAF = dissolved air flotation; dtpd = dry tons per day; lb/d = pound(s) per day; lb/hr = pound(s) per hour.

Table ES-2. Digester Capacity at EWPCF

Process	Technology	No. of Units		Condition	Design Loading Rate[1]	Measured Value	Percent of Capacity Used
		Total	Normal Service				
Digestion	Mesophilic Digesters	3	2	Average Volatile Solids Loading; All units in service	0.15 lb/cf/d	0.08 lb/cf/d	40%
				Average Volatile Solids Loading; Two units in service	0.18 lb/cf/d	0.12 lb/cf/d	67%
				Peak 2-week2 Volatile Solids Loading; All units in service	0.18 lb/cf/d	0.16 lb/cf/d	86%
				Hydraulic Loading; Two units in service	15 days minimum	19.6 days	77%
				Hydraulic Loading; All units in service	15 days minimum	29.3 days	51%

[1] *Digester capacities based on Brown and Caldwell standard design criteria for mesophilic digestion.*

[2] *Peaking condition was applied using the peaking factors developed in section 4.6.*

lb/cf/d = pound(s) per cubic feet per day.

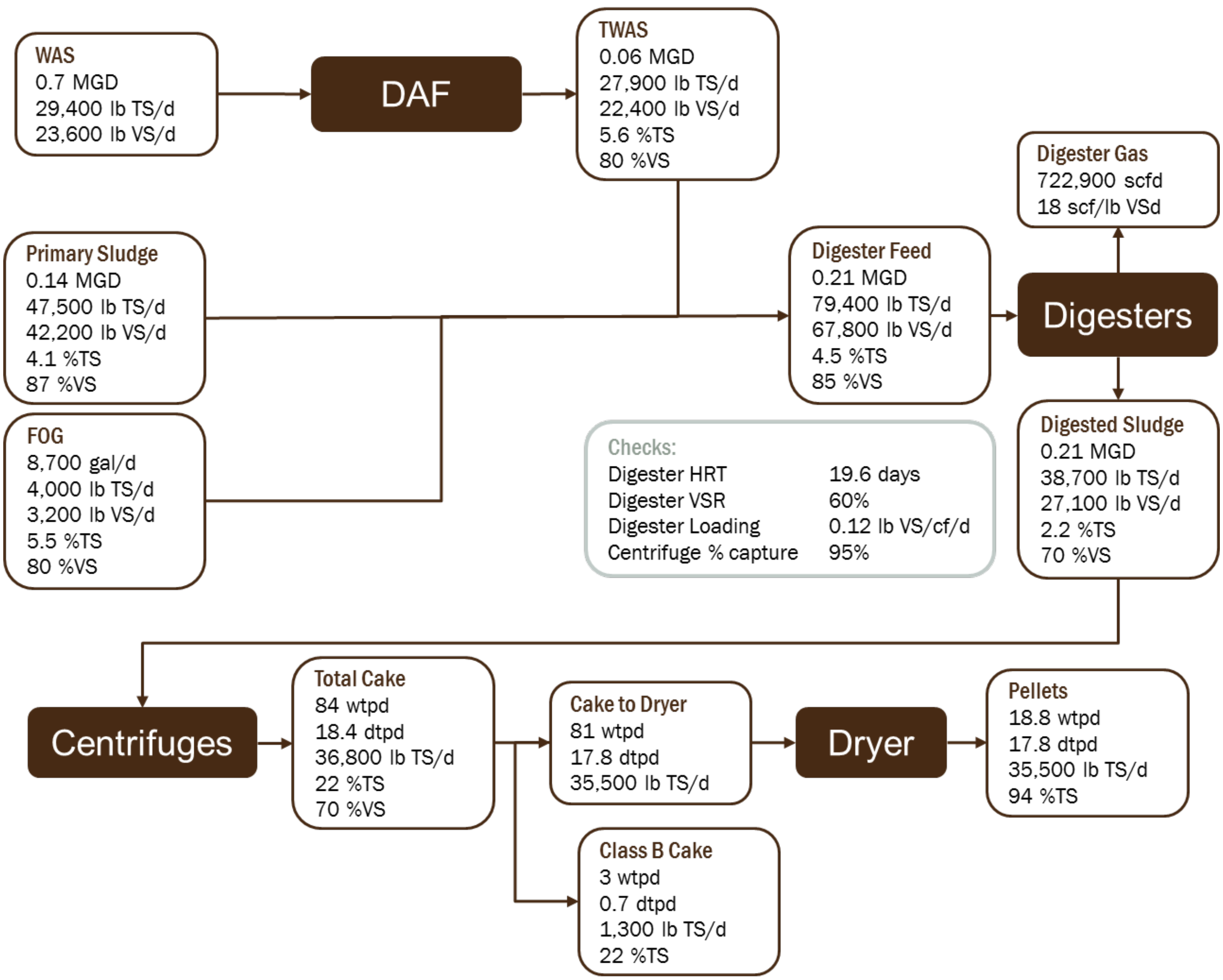

Figure ES-1. Process flow diagram describing the mass balance around the solids stream at EWPCF

Electrical and natural gas purchase and production data were analyzed to establish baseline energy values, summarized in Table ES-3. Self-generated electrical power was about 83 percent of the total electrical usage during the baseline period. Annual average production, import, and total usage in terms of kilowatts (kW) was calculated based on 8,760 hours per year.

Table ES-3. EWA Power Production and Demand Summary

	Annual Production, MWh	Annual Import, MWh	Annual Usage, MWh
June 2015 to May 2016	13,306	3,956	17,262
June 2016 to May 2017	13,200	2,796	15,996
	Annual Average Production, kW	**Annual Average Import, kW**	**Annual Average Usage, kW**
June 2015 to May 2016	1,519	452	1,971
June 2016 to May 2017	1,507	319	1,826

[1] Excluding September 2015 from calculation. Power import during this month was an order of magnitude higher than average values.

kWh = kilowatt hour; MWh = megawatt hour.

With respect to electrical costs, the majority of San Diego Gas and Electric (SDG&E) bills are charges for non-coincident (NC) demand and standby demand. On average, from February 2015 to March 2017, NC demand plus standby demand constituted 68 percent of the total SDG&E electricity bill. Average cost for electricity calculated in dollars per kWh ($/kWh), when all charges were included (total usage [kWh]/total electric charge), ranged from $0.19 to $0.40 $/kWh. If NC and standby demand charges are excluded, the calculated value drops to $0.09 to $0.11 $/kWh.

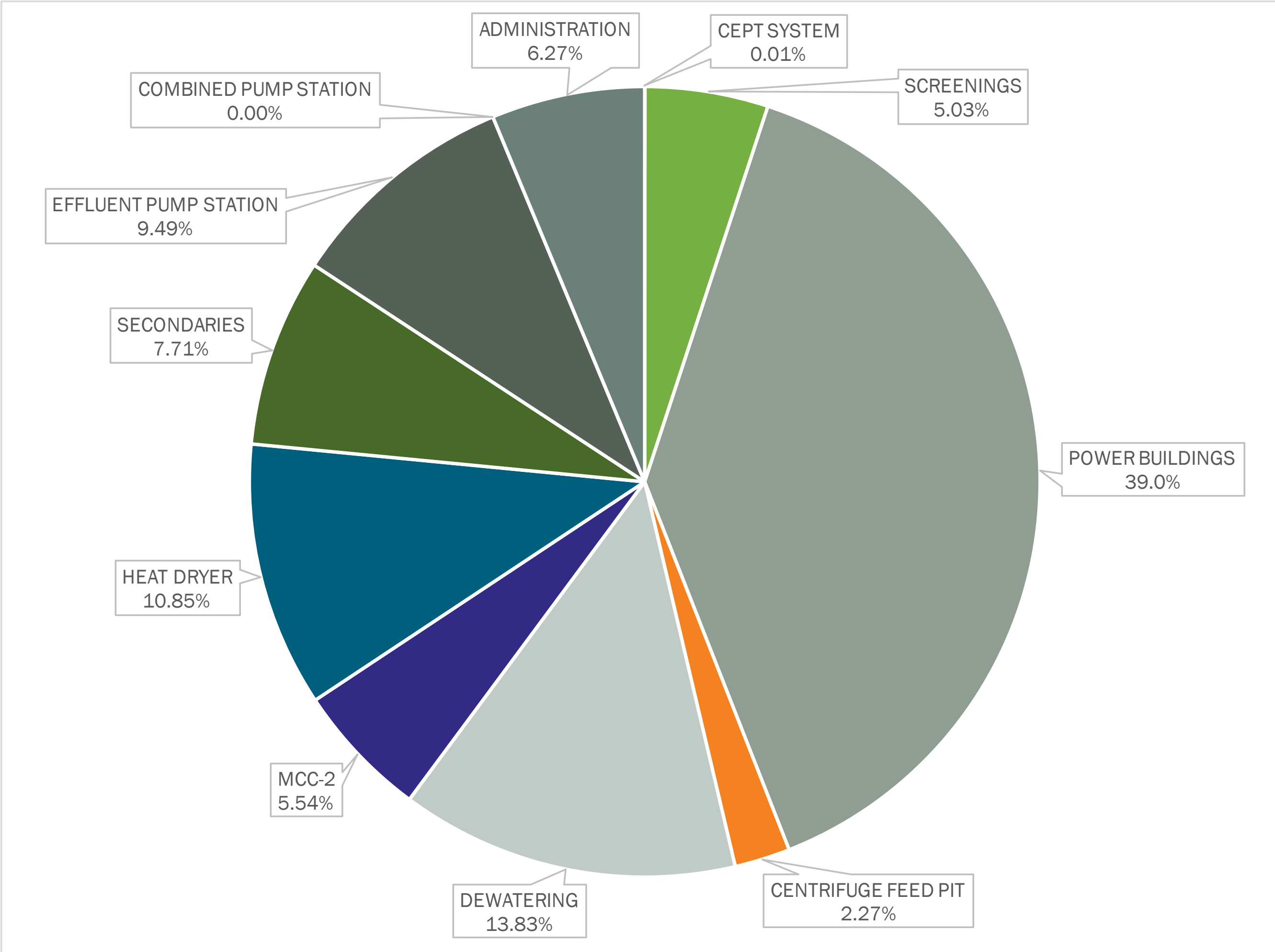

Figure ES-2. Average percent of electrical usage for each process building or function

CEPT = Chemically Enhanced Primary Treatment

When measuring biogas production, EWA takes flow measurements from each individual operating digester gas lateral (4, 5, and 6). Historical data from the 'Gas Data Monthly' information provided by Operations were used to determine the baseline biogas production. During this period, the digesters produced an average of 522 standard cubic feet (scf) per minute (scfm). Biogas production in terms of energy, volume, and flowrate that will be carried forward as the project baseline is summarized in Table ES-4. Biogas is used to either fuel the internal combustion engines, supplement gas demands in the solids dryer, or is wasted through the flare.

Table ES-4. Biogas Production Summary			
	Annual Production, therms	Annual Production, MMscf	Average Flowrate, scfm
Baseline	1,580,000	263.3	501

[1] *Assuming 600 British thermal units per cubic foot higher heating value for biogas.*

MMscf = million standard cubic feet.

Natural gas is used at the plant for a variety of uses in the following processes:

- Electrical power production in internal combustion engines (directly and through Eclipse air dilution unit)
- Sludge dryer
- Regenerative thermal oxidizer
- Space and water heating in the Administration and Maintenance Buildings
- Flare pilot light

Natural gas purchases are recorded by an EWPCF master meter and reported in volume (scf) and energy (therms) in monthly invoices. EWA also maintains several internal natural gas meters which were used to develop the baseline natural gas use throughout the plant. The total natural gas purchased by the EWPCF during the period between May 2015 through March 2017 was 1,633,000 therms. In-plant monitoring during that same period reported a usage of 1,610,000 therms—about 1 percent lower. The difference in recorded values is within acceptable tolerances for analysis and shows good agreement on flow meter accuracy. The unit cost for natural gas during the same period fluctuated month by month, ranging from $0.24 to $0.39 per therm, with an average of $0.31 per therm. Natural gas is purchased through a consortium which reduces cost compared to direct purchase from SDG&E.

Heat is produced at the plant via the engines and is utilized by the anaerobic digesters and an absorption chiller. The plant intends on transitioning from the absorption chiller to a conventional heating, ventilation, and air conditioning system; therefore, this demand will not be accounted for in future baseline heat demand. Available heat that can be recovered from the engines is estimated to be 40 percent of the fuel input based on previous studies for similar situations since historical data was not provided. With two 750 kW engines running at full output, approximately 6.0 million British thermal units (MMBtu) per hour (MMBtu/hr) can be recovered to the plant's hot water loop. The remainder of engine heat that is not needed is wasted to the plant's effluent. Dryer/regenerative thermal oxidizer (RTO) waste heat is discharged as hot air. The baseline heat production and usage are summarized in Table ES-5.

Table ES-5. Heat Production and Usage		
	Production, MMBtu/hr	Usage, MMBtu/hr
Engines	6.0	-
Dryer/RTO	1.4	-
Digesters	-	1.2
Total	7.4	1.2

Section 1: Introduction

The Encina Wastewater Authority (EWA) has undertaken a Biosolids Energy and Emissions Plan (BEE Plan), which will serve to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed Process Master Plan. The BEE Plan has several goals:

- Provide a comprehensive analysis of all project elements, including biosolids treatment, gas use, energy generation, and waste heat.
- Address capacity limitations in the solids handling process at the Encina Water Pollution Control Facility (EWPCF)
- Develop the most cost effective and sustainable solution for EWA
- Move the EWPCF towards greater energy independence
- Reduce greenhouse gas emissions

The outcome of this process is an implementable plan resulting in capital improvements to expand solids processing capabilities, maximize resource recovery capabilities for EWA, and optimize energy production. The BEE has been broken out into discrete tasks as follows:

1. Technical Memorandum (TM) 1: Baseline Energy Profiles and Projections
2. Technology Evaluation for Biosolids Handling
3. Technology Evaluation for Alternative Power Production
4. Technology Evaluation for Biogas Production
5. Technology Evaluation for Waste Heat
6. Air Emissions Evaluation
7. Alternative Scenarios Development, Evaluation, and Selection
8. Grants and Incentives

Tasks 2 through 5 involve technology evaluation in parallel to allow for the creation of holistic, end-to-end alternatives that include solids treatment, codigestion, gas use, waste heat use, and final biosolids disposition. These end-to-end alternatives are evaluated under Task 7. Task 6 will assess any regulatory limitations associated with emissions from selected processes. Task 8 is ongoing throughout the BEE Plan process and allows for the identification of grants and incentives, including their impact on the financial model used in Task 7.

The purpose of Task 1, summarized in this TM 1, is to establish the baseline for planning purposes. All subsequent sizing and process calculations will be based upon the data presented in this TM. The initial set of calculations described in Sections 2 through 4 was presented in a workshop with EWA staff on August 16, 2017, during which time EWA staff provided feedback and additional information.

Section 2: Existing Solids Mass Balance

A mass balance was performed on the solids handling process, tracking total and volatile solids (VS) through the treatment process at the EWPCF to determine baseline process operating conditions. Calculations were primarily based on 2-year average flows and loads using process data provided by EWA Operations staff ranging from May 2015 to June 2017. This section describes the calculations used in this evaluation and the results of the mass balance. Additionally, a summary of the solids stream process is provided below and several assumptions that were made during this evaluation are documented.

2.1 Summary of Solids Process Stream

The solids process stream at the EWPCF uses a combination of solids thickening, mesophilic digestion, and centrifuge dewatering to produce a Class B cake product. Additionally, a heat dryer is used to produce dried pellets. The process flow diagram in Figure 2-1 shows the major components.

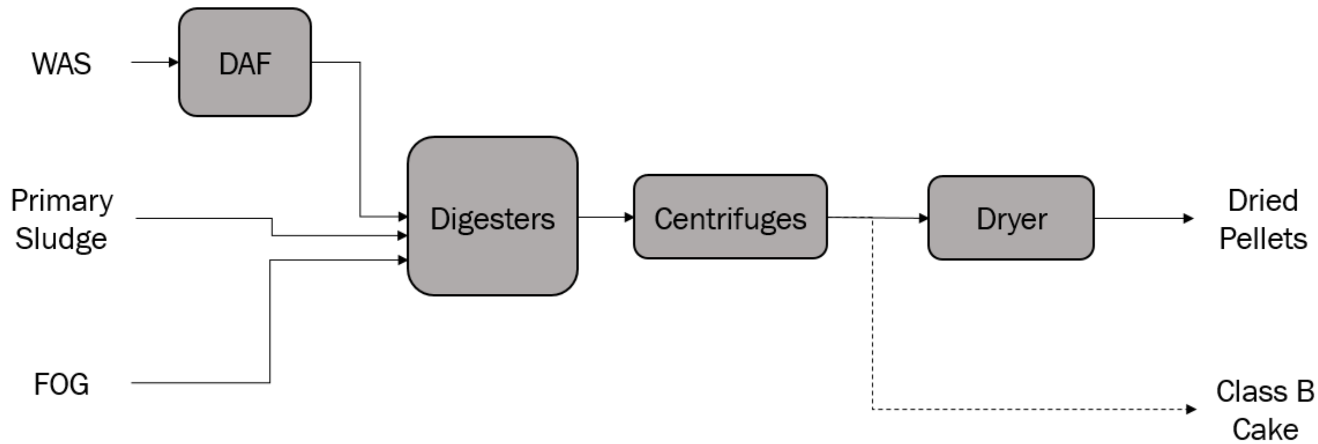

Figure 2-1. Solids process stream at EWPCF

Waste activated sludge (WAS) is thickened using dissolved air flotation (DAF) thickeners. The thickened WAS (TWAS) stream forms part of the digester feed. Primary sludge (PS) is fed directly to the digesters, as are inputs of high strength waste (primarily fats, oil and grease [FOG]), which are trucked in 5 to 6 days a week. Digested sludge is dewatered using centrifuges, and the cake produced is typically dried in a drum dryer. The typical service condition involves the use of one out of three DAF units, two out of three large digesters, two out of three centrifuges, and use of the single drum drying unit to generate granules. Class B dewatered cake is hauled directly to beneficial use sites when the dryer is not in service (i.e., due to extended maintenance outages).

A summary of the rated capacities of each of the solids stream processes is provided in Table 2-1 for non-digestion processes and in Table 2-2 for digestion process. The percent of total capacity that is used with current loading under average and peak conditions is also summarized. Note that these loads are based on the calibrated mass balance described in the next section. It is worth noting that the post-digestion processes may not see peak day solids loads since the digested sludge storage tank provides some buffering capacity. The digested sludge storage tank could provide 0.9 day of retention time at peak day condition.

Table 2-1. Major Non-Digestion Solids Stream Processes and Corresponding Capacities at EWPCF								
Process	Technology	No. of Units		Capacity		Percent of Capacity Used		
		Total	Normal Service	Design Loading Rate[5]	Total Service Capacity	Average Annual Condition	Peak Month Condition[6]	Peak Day Condition[6]
Thickening	DAF	3	2	0.72 lb/hr/sf	90,000 lb/d[1]	33%[2]	40%	53%
Dewatering	Centrifuges	3	2	3,000 lb/hr	144,000 lb/d	26%[3]	32%	42%
Solids Drying	Thermal Dryer	1	1	30 dtpd	30 dtpd	60%[4]	74%	96%

[1] Calculated assuming two 40-ft diameter DAF units in normal service.

[2] Calculated using average dry solids loading from calibrated mass balance (29,400 lb/d) to two 40-ft diameter service DAF units.

[3] Calculated using average dry solids loading from calibrated mass balance (38,700 lb/d) to service centrifuges.

[4] Calculated using average dry solids loading from calibrated mass balance (17.8 DTPD) to dryer.

[5] Thickening and dewatering capacities provided in the 2016 Process Master Plan. Dryer capacity provided by vendor.

[6] Peaking conditions were applied using the peaking factors developed in section 4.6.

dtpd = dry tons per day; lb/d = pound(s) per day; lb/hr = pound(s) per hour; lb/hr/sf = pound(s) per hour per square feet.

Table 2-2. Digester Capacity at EWPCF							
Process	Technology	No. of Units		Condition	Design Loading Rate[1]	Measured Value	Percent of Capacity Used
		Total	Normal Service				
Digestion	Mesophilic Digesters	3	2	Average Volatile Solids Loading; All units in service	0.15 lb/cf/d	0.08 lb/cf/d	40%
				Average Volatile Solids Loading; Two units in service	0.18 lb/cf/d	0.12 lb/cf/d	67%
				Peak 2-week2 Volatile Solids Loading; All units in service	0.18 lb/cf/d	0.16 lb/cf/d	86%
				Hydraulic Loading; Two units in service	15 days minimum	19.6 days	77%
				Hydraulic Loading; All units in service	15 days minimum	29.3 days	51%

[1] Digester capacities based on Brown and Caldwell standard design criteria for mesophilic digestion.

[2] Peaking condition was applied using the peaking factors developed in section 4.6.

lb/cf/d = pound(s) per cubic feet per day.

2.2 Assumptions

While the mass balance was based on plant data from the 2-year period spanning from May 2015 to June 2017, not all the data were directly applied to the calculations. The mass balance was calibrated using several alterations based on discussions with EWA staff and extensive review of the historic data. This resulted in some parameters that were changed from measured historic values. To summarize the process of developing and calibrating the mass balance, the reported daily masses of dewatered cake and pellets were used, along with an assumption on centrifuge capture rate in order to determine digested sludge loads. Assumptions on VS reduction (VSR) were then used to back-calculate digester loading. WAS and FOG data were deemed reliable by EWA Operations. Therefore, WAS load was used to forward calculate TWAS load, with a DAF capture rate assumption, and this was combined with total digester load to estimate primary sludge load.

Details on the assumptions made in developing and calibrating this mass balance are documented below.

- TWAS data was forward-calculated using the WAS data and an assumed DAF removal of 95 percent. The VS fraction was assumed to be the same for WAS and TWAS based on an average of the percent VS determined in the lab.
- The EWPCF uses Chemically Enhanced Primary Treatment (CEPT) whereby ferric chloride and polymer are added to the wastewater prior to the primary clarifiers to improve clarifier solids removal, reduce the load on the secondary treatment process, and provide a ferric dose in the sludge that acts to limit sulfide content in the digesters and limit the hydrogen sulfide concentration within the digester gas. The dose of ferric chloride used at EWA is about 15 milligrams per liter (as $FeCl_3$). The extra solids removed in the primaries, along with the chemical sludge, is all part of the total PS quantities discussed within this TM.
- Total solids (TS) measurements in the FOG stream were provided by EWA. Due to the high variability in the data (0.4 to 26 percent), the average FOG concentration of 5.5 percent was applied to the entire evaluation period. Additionally, the 2016 Process Master Plan (PMP) assumed that the volatile fraction of total solids was 80 percent; this assumption was used in the mass balance.
- FOG input data during the period from March 28 to April 28, 2017, were excluded because this period included the input of brewery waste, which is not representative of normal operation.
- Daily Class B cake and dried granule production masses were averaged inclusive of zero values. This is because Class B cake and dried pellets are not usually produced simultaneously, based on dryer operation.
- The centrifuge has an assumed capture rate of 95 percent. The assumption was used to back calculate the digested solids.
- VSR was determined using Van Kleeck and mass balance methods, yielding 57 percent and 63 percent, respectively. Based on discussions with operations at EWPCF, 60 percent VSR was used to back calculate the influent load into the digesters.
- Based on discussion with EWPCF staff, the TWAS and FOG feed were held constant and based on historical data. The PS feed was the reminder of the calculated digester feed. However, the PS, TS and VS were based on historical data.

2.3 Results

Figure 2-2 summarizes the results of the mass balance. The mass balance values reported here and shown in Figure 2-2 are based on the average of daily values over the 2-year analysis period, with loadings rounded to the nearest 100 pounds per day (ppd). WAS is thickened in the DAF units from a TS concentration of approximately 0.5 to 5.5 percent. The VS fraction is 80 percent in the WAS stream. Primary sludge is pumped at an average total solids concentration of 4.1 percent, with a volatile fraction of 87 percent, fed directly to the digesters. FOG was assumed to be received at an average total solids concentration of about 5.5 percent with a volatile fraction of 80 percent. Primary sludge contributes to about 62 percent of total solids fed to the digesters; TWAS contributes about 33 percent, and FOG accounts for about 5.4 percent.

The digesters receive an average flow of about 0.21 million gallons per day (MGD) from the above three sources, resulting in a retention time of about 19.6 days with two digesters (2.05 million gallons each) in service. The TS load in the digester feed is about 79,400 ppd, and the VS load is about 67,800 ppd. This results in a digester loading rate of about 0.12 pounds of VS per cubic foot per day. Digested sludge is fed to the dewatering centrifuges at a total solids concentration of about 2.2 percent and a volatile fraction of about 70 percent. This results in centrifuge loading rates of about 38,700 ppd TS and 27,100 ppd VS. The centrifuges produce a Class B cake at a solids concentration of about 22 percent at about 84 wet tons per day or 18.4 dry tons per day. This cake is usually further processed into pellets using a heat dryer, and the pellet product is trucked off site. On rare occasions when the dryer is out of service for unscheduled maintenance, the dewatered Class B cake is hauled off site as is. Averaging these production values over the 2-year analysis period, the dryer was found to produce about 17.8 dtpd of pellets with a solids content of about 94 percent. Class B cake that is not dried is produced at an average rate of about 0.7 dtpd.

Table 2-3 summarizes the major parameters that describe operating conditions in the solids stream at the EWPCF. Figure 2-2 summarizes the mass balance values described above within a process flow diagram. All values in the figure describe averages over the 2-year period (May 2015 to June 2017) with loadings rounded to the nearest 100 ppd. As discussed earlier, it was determined after a thorough review of the historic data and discussions with EWPCF staff that measured values for certain parameters may not have been accurate and some sampling changes should be considered to try and improve accuracy in certain areas and verify the major operating parameters shown in Figure 2-2 are accurate.

Table 2-3. Summary of Average Operating Conditions (2015-2017)

Parameter	Units	Calculated Value
Digester Retention Time	days	19.6[1]
Digester VSR	percent	60[2]
Digester Volatile Solids Loading Rate	lb-VS/(ft^3·d)	0.11
Digester Gas Production	scf/lb-VS_d	18
Centrifuge Capture Rate	Percent	95

[1] Assuming two digesters in service.

[2] Assumed based on mass balance data, Van Kleeck calculations, and engineering experience.

lb-VS/(ft^3 d) = Pounds VS per cubic foot per day;

scf/lb-VS_d = standard cubic feet per pound VS destroyed.

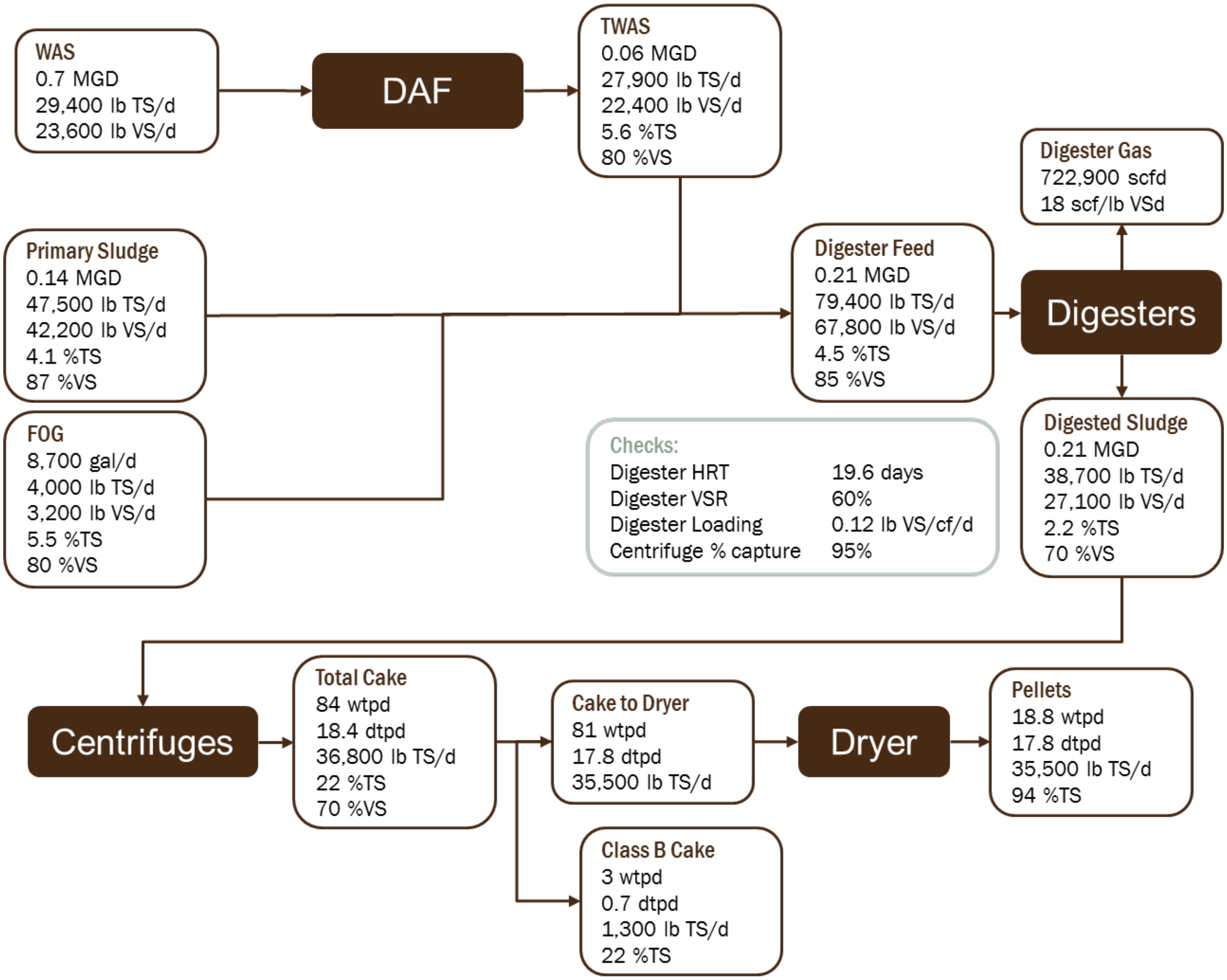

Figure 2-2. Process flow diagram describing the mass balance around the solids stream at EWPCF

Section 3: Existing Energy Balance

The baseline energy balance summarized in this section includes production and demand for biogas, electricity production, purchase and use, and natural gas demand and heat production. Historical data from June 2016 to May 2017 was used to calibrate the baseline values. Trends were plotted over a 2-year period, but Brown and Caldwell was notified that the plant replaced aeration basin diffusers mid-2016, and therefore, the data from June 2016 is more representative of the plant's baseline moving forward. This section describes the data used and the parameters modified to calibrate the model.

3.1 Electrical Energy Analysis

This section summarizes the electrical analysis conducted to support the calculated baseline values model including evaluations of electrical energy production, use, and cost.

3.1.1 Electrical Energy Production and Use

EWA has four total 750 kilowatt (kW) Caterpillar engines, but typically operates two engines continuously at maximum output due to current air permit limitations on carbon monoxide emissions of 100 tons per year. During typical operation, two engines are fueled with unconditioned biogas. When biogas production is low, natural gas is air-diluted in an Eclipse unit and added to the engines' fuel stream to meet full engine output. Additionally, during utility peak power demand periods, the plant often runs a third 750 kW engine on natural gas and physically disconnects (island mode) from the grid to meet the plant's demand. Each engine is equipped with dual fuel capabilities.

Figure 3-1 shows the engine fuel consumption for both biogas and natural gas in units of therms, or energy. It was assumed that biogas has a higher heating value (HHV) of 600 British thermal units (Btu) per cubic foot (Btu/cf) and natural gas has a HHV of 1,000 Btu/cf. Over the baseline period, approximately 91 percent of the engine fuel input is sourced by biogas and the remaining 9 percent is sourced by natural gas. Note that November 2015 data is reported as an outlier due to an increase in natural gas consumption while a biogas flex coupling was being repaired.

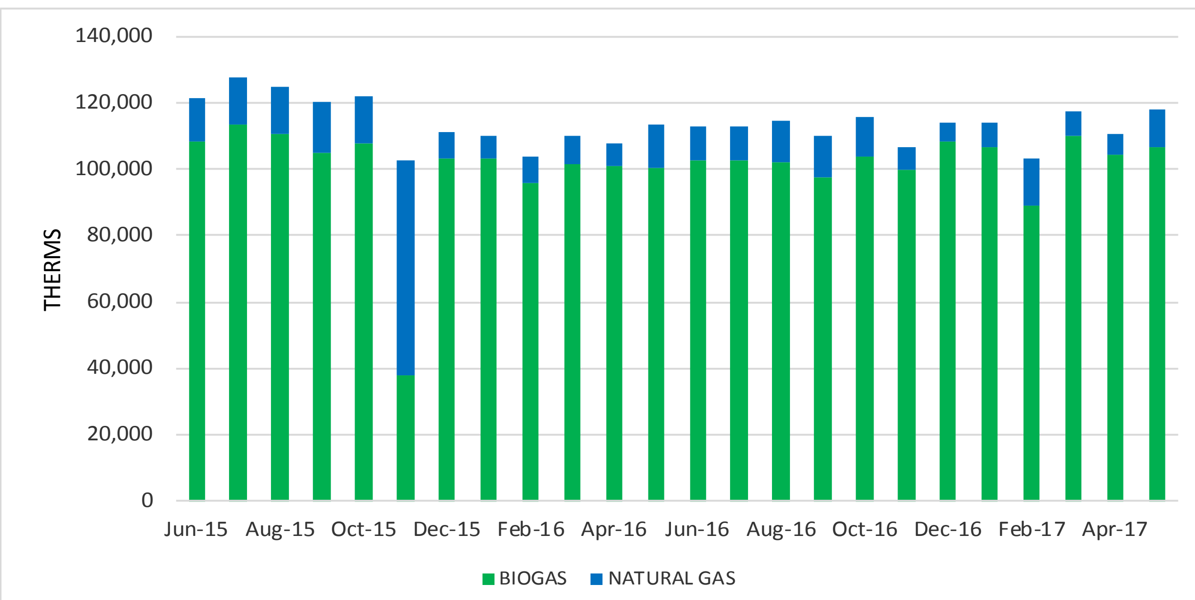

Figure 3-1. Biogas and natural gas engine fuel consumption

Historical data over the baseline period was used to determine the power production and import. Plant staff indicated that the aeration diffusers were replaced with more efficient ones in mid-2016 (June), which is consistent with the decreased power usage. The baseline electricity usage will be determined based on data during the time following the installation of the new diffusers. Total annual power production and consumption is summarized in Table 3-1 and Figure 3-2. The annual power production is based on data from the California Energy Commission meters, which includes electricity generated by both the biogas and natural gas. The annual import is based on the 'Gas Data Monthly' information provided by the plant, and total usage is calculated as the sum of the production and import values.

Self-generated electrical power was about 83 percent of the total electrical usage during the baseline period. Annual average production, import, and total usage in terms of kW was calculated based on 8,760 hours per year.

Table 3-1. EWA Power Production and Demand Summary

	Annual Production, MWh	Annual Import, MWh	Annual Usage, MWh
June 2015 to May 2016	13,306	3,956	17,262
June 2016 to May 2017	13,200	2,796	15,996
	Annual Average Production, kW	**Annual Average Import, kW**	**Annual Average Usage, kW**
June 2015 to May 2016	1,519	452	1,971
June 2016 to May 2017	1,507	319	1,826

[1] Excluding September 2015 from calculation. Power import during this month was an order of magnitude higher than average values.

MWh = megawatt hour.

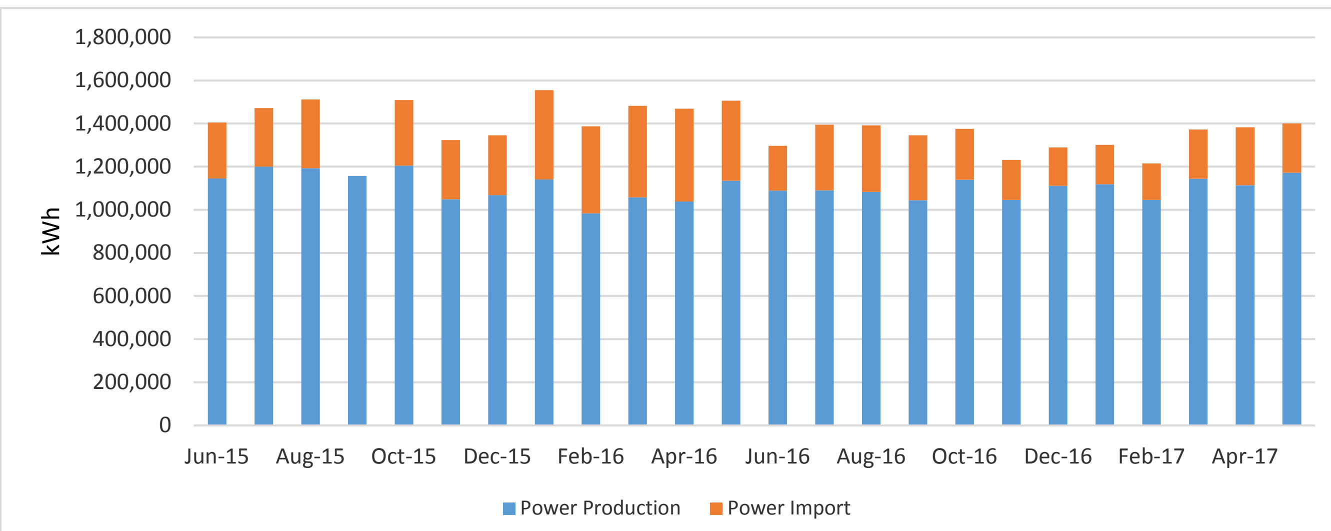

Figure 3-2. Power production, import, and demand by month

Note: Self-generated power is approximately 83 percent of plant usage; September 2015 power import data removed from set as an outlier.

The following data were used to establish baseline power demand:

- Run hour data was used to approximate the percentage of total electrical usage for each unit process or location.
- Engine output electrical meter data and power import from San Diego Gas and Electric (SDG&E) bills were used to determine the total plant usage (not the “gas monthly” data).

The distribution of electricity use at the EWPCF was estimated based on run hour data provided by EWA. EWA monitors each system’s run hours on a monthly basis. These run hours are used to calculate kW hours (kWhs) per month usage using an assumed power factor and average utilization (varied depend on equipment). Run hour data was provided from February 2015 through June 2017. Note that this projection likely overestimates total usage as compared to actual measured generation and SDG&E import and should only be used to qualitatively compare different parts of the plant’s electrical usage. The average percent of electrical usage for each process during that period is provided in Figure 3-3. As shown in Figure 3-3, 40 percent of the monthly kWh usage is for the power buildings, which holds equipment such as fans, pumps for hot and chilled water, and blowers. Seventy-nine (79) percent of the power consumed at the plant is dependent on flow and administrative uses, with 21 percent of the total energy use related to solids loading.

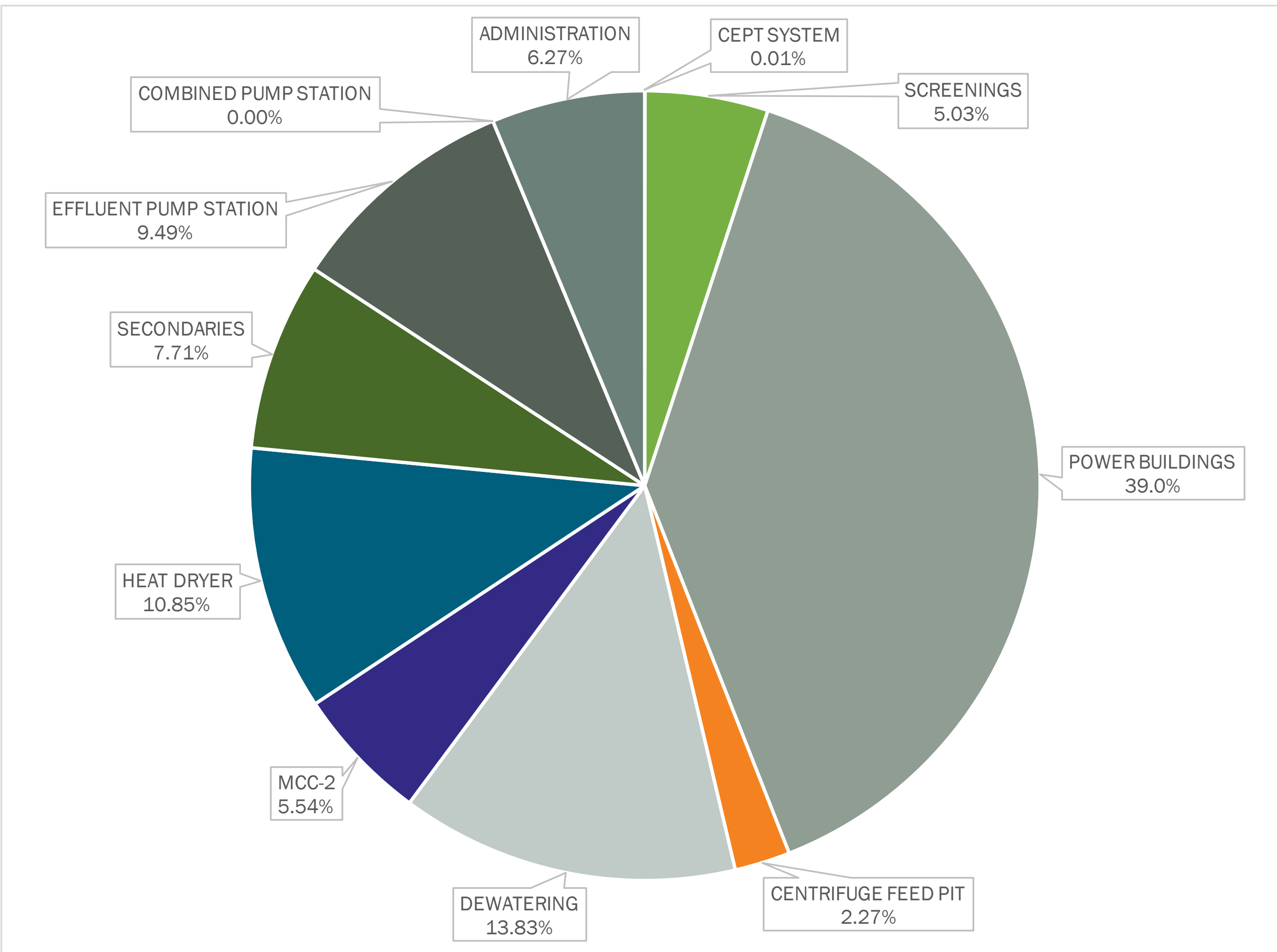

Figure 3-3. Annual average percent of electrical usage for each process building or function

Total monthly energy demands and digester feed loads were used to decouple the energy involved in the solids treatment processes from the energy used for all other processes. Average daily energy demands (kWh per day [kWh/day]) and digester feed loads (lb/day) are plotted in Figure 3-4 for the months between June 2016 and May 2017. June 2016 was chosen as the starting month due to the installation of new aeration basin diffusers which significantly lowered average energy consumption. April 2017 was excluded due to the lack of digester feed loading values. A linear fit of this data provides a distinct relationship between solids loading and solids treatment energy consumption that is independent of the energy demand of liquid stream processes and administrative uses. Extrapolation of the linear fit points to an energy demand of 34,600 kWh/day that is independent of solids loading. The decoupling of energy demands allows for a more accurate prediction of increase in energy demand as it relates to future increases in solids loading. To correct for potentially inaccurate PS solids loading data, a reduction factor was applied to each month's primary sludge total solids loading. The correction factor was determined by the percent decrease in PS total solids from the annual average data to the extrapolated values used to predict future loads.

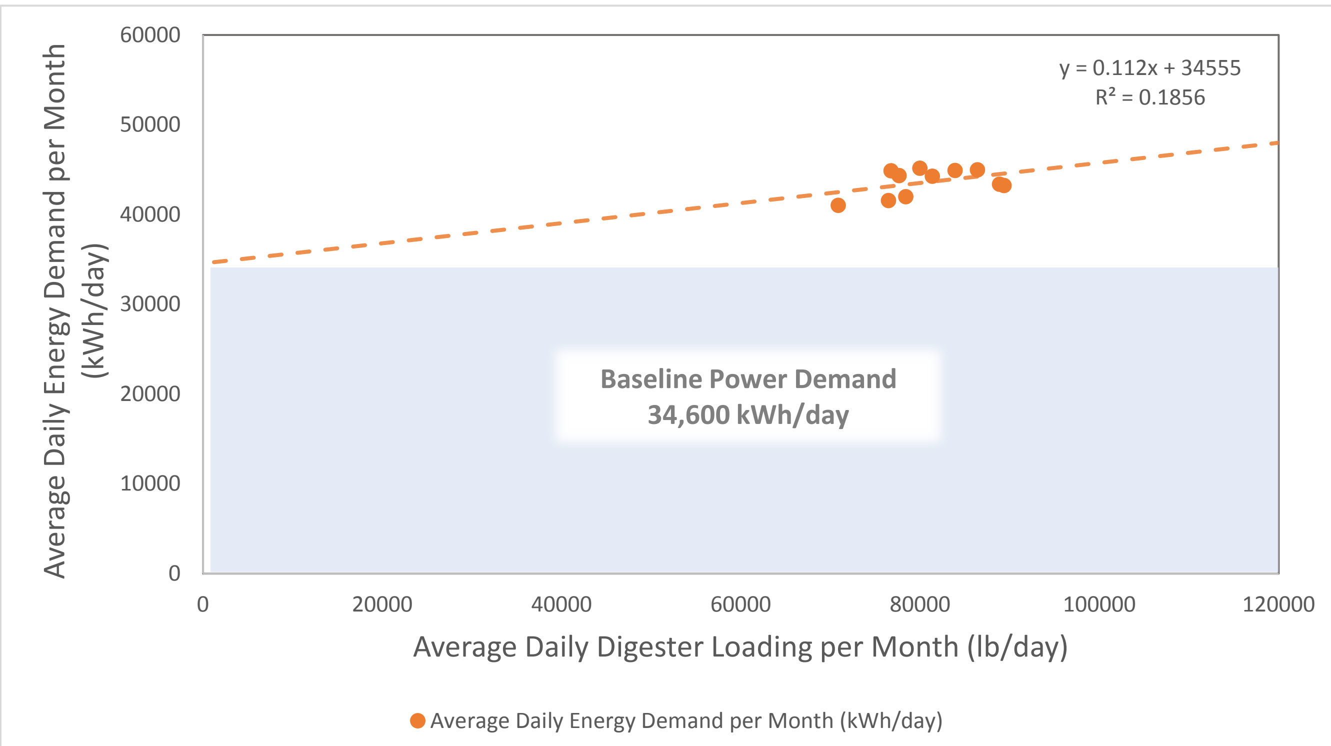

Figure 3-4. Daily energy demand dependence on daily digester loading and determination of baseline energy demand

3.1.2 Baseline Electricity Cost Analysis

To conduct the baseline electricity cost analysis, EWA provided SDG&E electricity bills from February 2015 through March 2017. However, as described previously, the plant replaced aeration basin diffusers mid-2016; therefore, the data after that replacement is more representative of the plant's baseline energy cost. It should be noted that while SDG&E bills EWA monthly, the pay periods begin and end in the middle of the month. For the purposes of this TM, bills are noted by the end date of the billing period (i.e., "February 2015" represents a pay period from January 13 through February 11, 2015). Thus, the baseline electricity cost was analyzed from July 2016 through March 2017.

During this analysis period, EWA's monthly power purchase from SDG&E ranged from 167,300 kWh (November 2016) to 341,770 kWh (September 2016). The average monthly kWh purchase during this period was 226,900 kWh

SDG&E bills EWA on a monthly basis, and the costs are a summation of a variety of charges, including:

- Electricity generation: cost per kWh for the source generation of consumed electrical energy.
- Electricity delivery: cost per kWh for the transmission and distribution of consumed electrical energy.
- On-peak demand: cost per kW for the maximum 15-minute power demand during peak periods.
- Non-coincident demand: cost per kW for the maximum 15-minute power demand during non-peak periods (non-coincident with the maximum grid demand).
- Standby demand: fixed charge per kW of on-site generator capacity for SDG&E to reserve an equivalent amount of grid system capacity in the event of a generator shutdown—charged every month whether used or not.

The breakdown of each bill is provided in Figure 3-5.

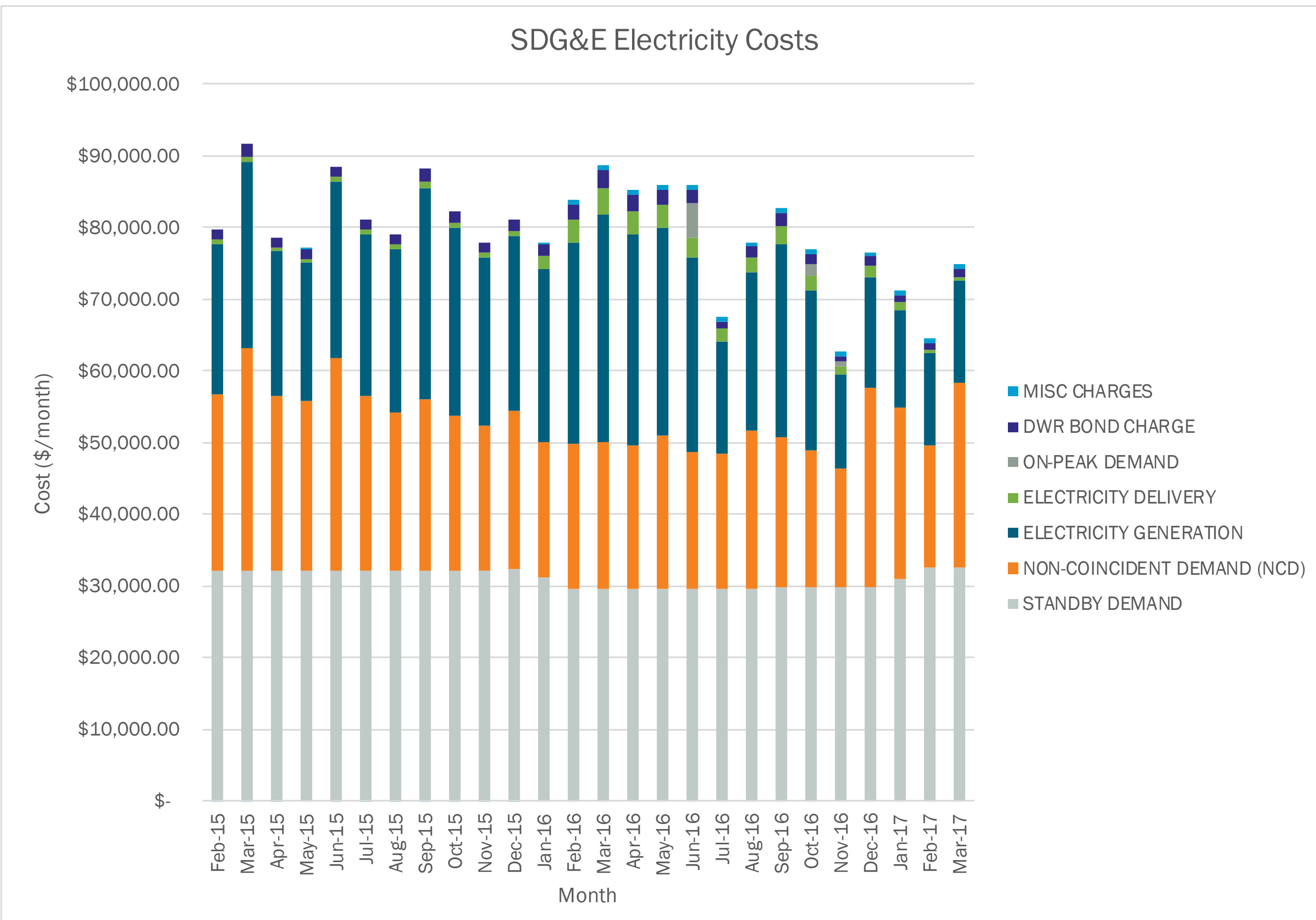

Figure 3-5. Breakdown of monthly SDG&E bills

As shown in the figure above, the majority of the SDG&E bill are charges for non-coincident (NC) demand and standby demand. On average, from July 2016 to March 2017, NC demand plus standby demand constituted 71.3 percent of the total SDG&E electricity bill. The standby demand is based on an installed capacity of 2,295 kW. Average cost for electricity calculated in dollars per kWh ($/kWh), when all charges were included (total usage [kWh]/total electric charge), ranged from $0.24 to $0.40 $/kWh. If NC and standby demand charges are excluded, the calculated value drops to $0.09 to $0.10 $/kWh.

3.1.2.1 SDG&E Electric Rate Schedule

In April 2016, SDG&E implemented, and EWA adopted, a revised time of use (TOU) electric rate schedule called TOU Plus. This new schedule incorporated a demand response element into a normal TOU rate schedule; a summary is provided below.

- Customers select a Capacity Reservation, in kW, with an associated monthly payment of $6.14/kW
- Up to 18 times a year, the utility calls for Critical Peak Pricing Event Days; during these days, any demand in excess of the Capacity Reservation is billed at a much higher rate
- The EWA has a capacity reservation of 0 kW, meaning no reservation charges are added and no capacity is reserved for peak days

Brown and Caldwell recommends an evaluation of the most applicable rate schedule for EWA as part of the current energy planning effort.

3.2 Biogas Production and Use

The plant measures biogas production from each individual operating digester gas lateral (4, 5, and 6) as well as biogas usage in the engines, dryer, and waste gas flare. Historical data from the 'Gas Data Monthly' information was used to compare the biogas production and usage. In theory, the total production should equal the usage (including wasting), however, data from the baseline period indicates that the digesters produced an average of 521 standard cubic feet (scf) per minute (scfm) of biogas while only 473 scfm was utilized. Another source of digester gas data was from the historical SCADA data. The individual digesters indicate that the digesters produce an average of 502 scfm. Biogas flow meters located closer to the digesters are notorious for inaccuracy, therefore, a third approach using a common VSR calculation was performed. Figure 3-7 illustrates the variance between biogas production and use.

The VSR calculation uses assigned percent VS and VSRs for each digester feedstock (PS, TWAS, FOG) to determine the quantity of VS destroyed in the digester. For every pound of VS destroyed, it was assumed that 18 cubic feet of digester gas are produced. Applying the VSR method to the digester solids loading resulted in a biogas production of 501 scfm, which is more consistent with the end use meters and falls between the range of the production meters and end use meters. The biogas production will be based on the VSR method and is summarized in Table 3-2 in terms of energy, volume, and flowrate.

Table 3-2. Biogas Production Summary

	Annual Production[1], therms	Annual Production, MMscf	Average Flowrate, scfm
Baseline	1,580,000	263.3	501

[1] *Assuming 600 Btu/cf HHV for biogas*

MMscf = million standard cubic feet.

Biogas is used to either fuel the internal combustion (IC) engines, supplement gas demands in the solids dryer, or is wasted through the flare. Figure 3-6 shows the baseline quantity of biogas that is used for each process during the baseline period. Biogas usage in November 2015 is included in the graphical figure but will not be used to determine the baseline biogas use since it was an anomaly month where most of the biogas was flared. Since the solids dryer operates 11 days on, 3 days off, 3/14 of the time, excess biogas not utilized in the engines is flared while the dryer is not operational. Additionally, the gas control valve to the dryer is manually set rather than automated, which results in flaring of biogas when production is high. Brown and Caldwell recommends automating the control valve to allow the dryer to operate on blended biogas and natural gas rather than flaring biogas.

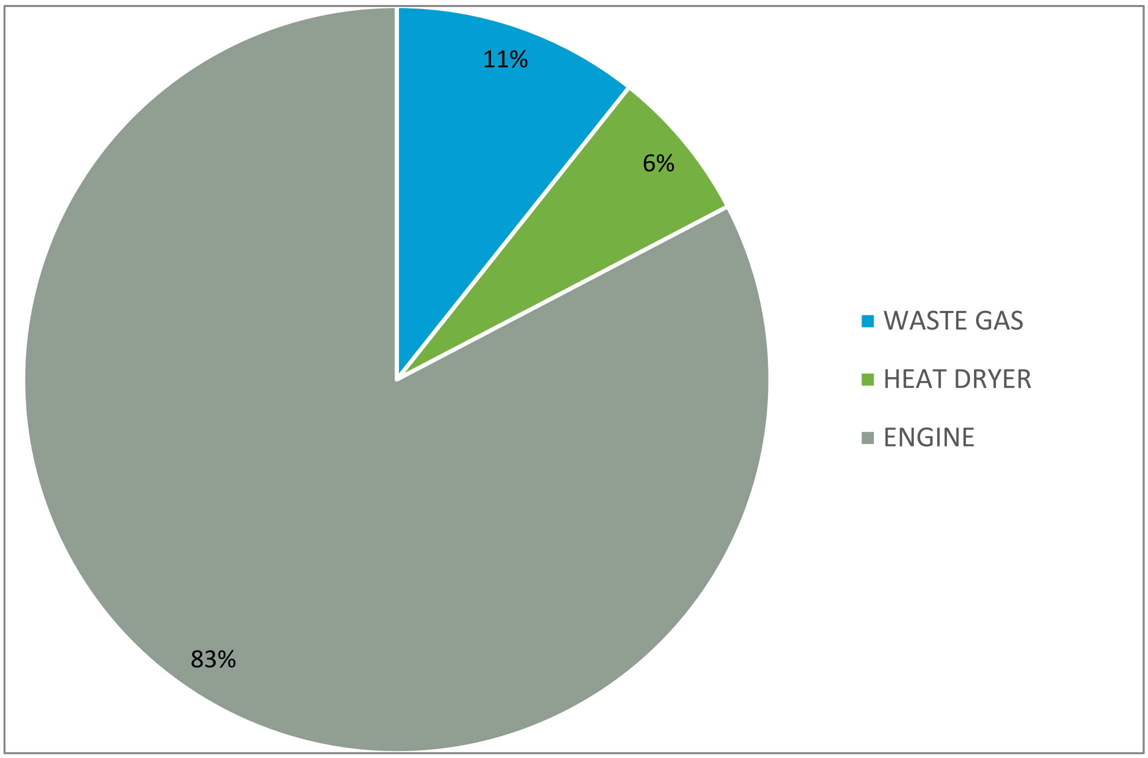

Figure 3-6. Biogas usage during Baseline Period (June 2016 to May 2017)

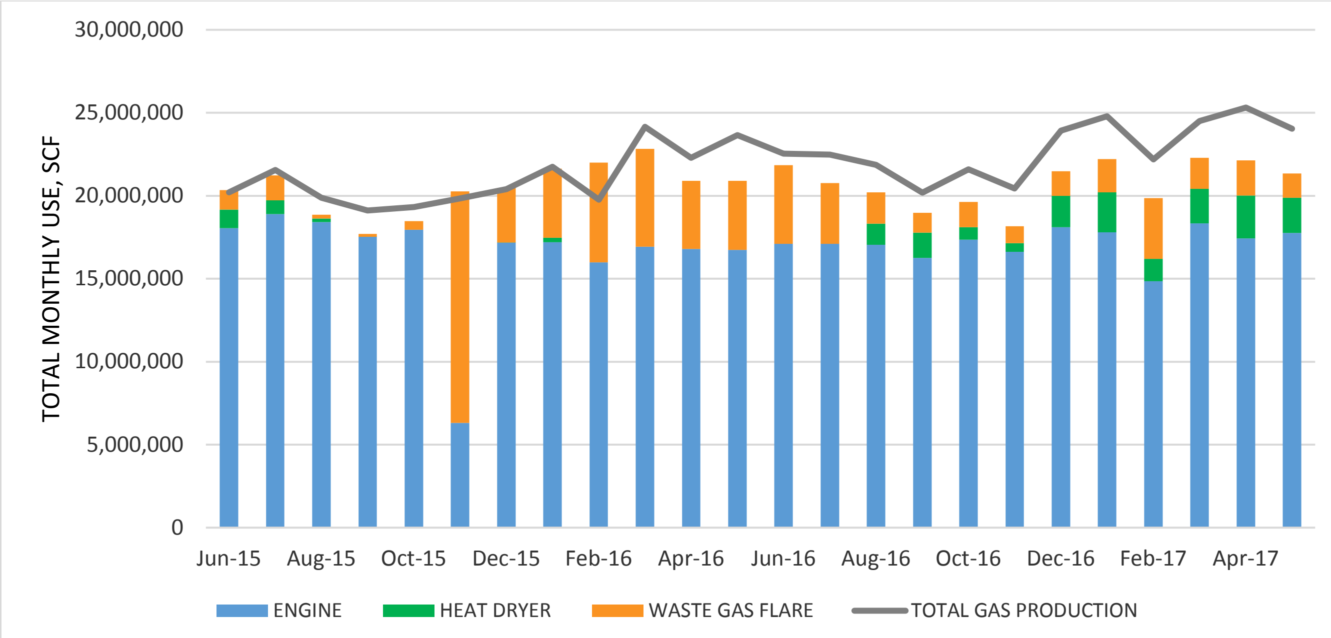

Figure 3-7. Biogas summary: usage and production

3.3 Natural Gas Analysis

This section summarizes the natural gas analysis conducted to support the calculated baseline values during June 2016 to May 2017, which includes evaluations of natural gas usage and cost.

3.3.1 Natural Gas Usage

Natural gas usage is recorded for both plant totals and individual processes. Natural gas is used at the plant for a variety of uses in the following processes:

- Electrical power production in internal combustion engines (directly and through Eclipse blending unit)
- Heat dryer – plant operates 11 days on, 3 days off.
- Regenerative thermal oxidizer (RTO) (as part of the sludge dryer exhaust treatment)
- Space and water heating in the Administration and Maintenance Buildings
- Flare pilot

Natural gas purchases are recorded by a master meter and reported in scf by EWA and therms in the monthly invoices. EWA also maintains several internal natural gas meters which were used to develop the baseline natural gas use throughout the plant. EWPCF's natural gas meters recorded usage data that was consistent with the SDG&E billing statements.

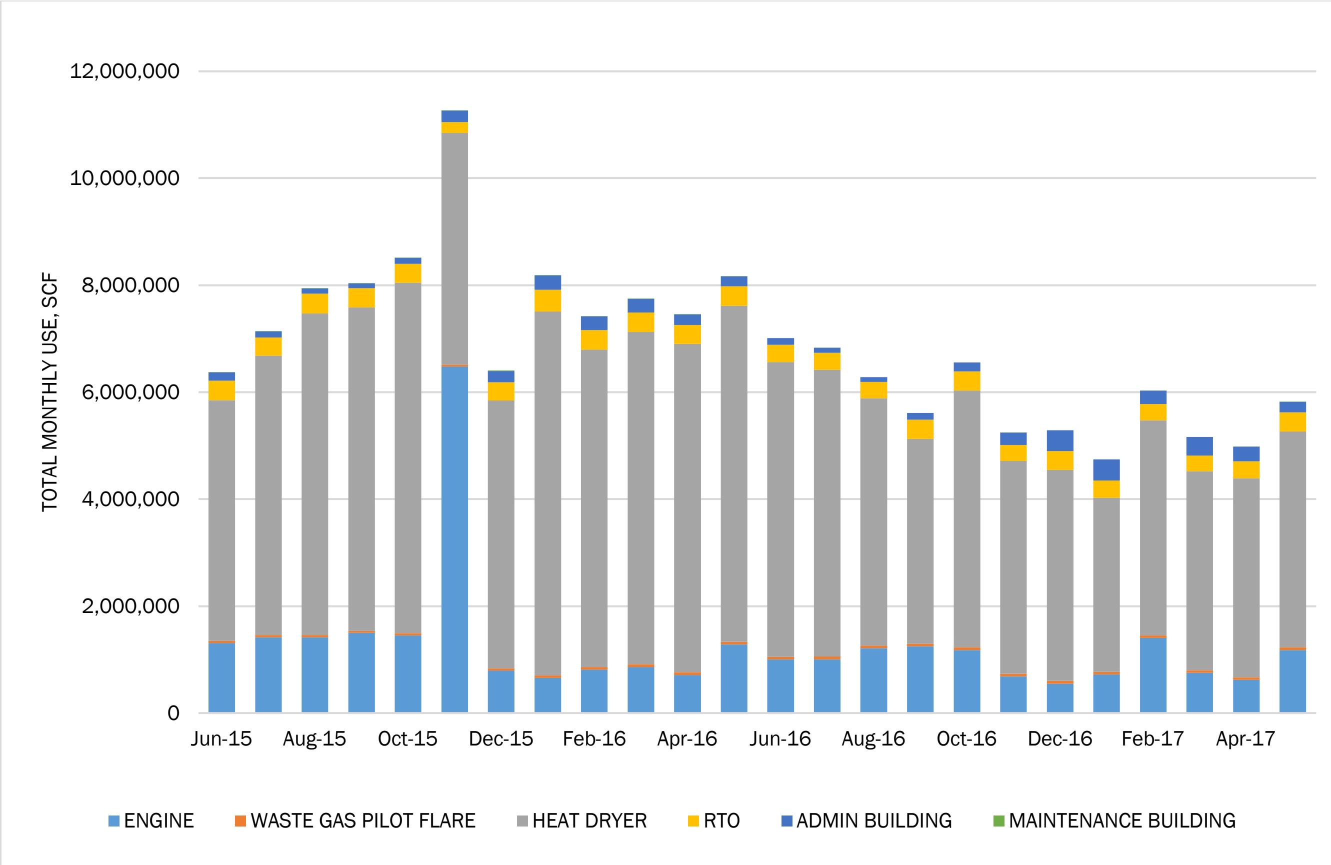

Figure 3-8. Natural gas use by process/location at EWPCF

Table 3-3. Natural Gas Baseline Use in Therms

	Engine	Pilot Flare	Heat Dryer	RTO	Admin Bldg.	Maintenance Bldg.	Total
June 2015 to May 2016*	132,140	5,857	745,562	45,076	22,906	405	951,546
June 2016 to May 2017	115,630	5,986	507,894	39,294	26,841	11	695,656

**Excluding November 2015 in which natural gas use in the engines was significantly greater than other months, likely due to an operational change.*

Totalized natural and digester gas use from both the heat dryer and RTO was used along with totalized digester feed loading to determine a directly proportional relationship between the two for prediction of future gas demands. Since the relationship between natural gas demand and solids drying is not affected by the replacement of aeration basin diffusers, the data used spans over a longer period to provide a better average gas demand per pound of solids. Between the months of February 2016 to May 2017, excluding April 2017, a total of 36.5 million pounds of solids were fed to the digesters while the heat dryer and RTO consumed a total of 85,100 million Btu (MMBtu) worth of natural and digester gas. Energy used to pre-heat the dryer is approximately 2 MMBtu per hour (MMBtu/hr) for 30 minutes; therefore, each time the dryer starts up, 1 MMBtu is consumed. Over the course of a year, this equates to roughly 26 MMBtu, which is less than 1 percent of the typical energy demand. Therefore, it can be assumed that the dryer gas consumption is nearly linear to solids loading. Assuming the dryer and RTO do not consume energy when there is no solids load, a direct relationship between the two can be established at 0.0023 MMBtu consumed per pound of solids processed.

3.3.2 Natural Gas Costs

EWA purchases natural gas from the Department of General Services Natural Gas Program (DGS) and the costs are calculated as a unit cost per therm. For the cost analysis, EWA provided monthly billing data from May 2015 through March 2017. The total natural gas purchased by the EWPCF during the period between May 2015 through March 2017 was 1,633,000 therms. In-plant monitoring during that same period reported a usage of 1,610,000 therms—about 1 percent lower. The difference in recorded values is within acceptable tolerances for analysis and shows good agreement on flow meter accuracy.

The therms purchased from DGS during that period ranged from 48,600 therms (January 2017) to 120,100 therms (November 2015), and averaged 71,000 therms per month. The per unit commodity cost for natural gas during the same period fluctuated month by month, ranging from $0.24 to $0.39 per therm, with an average of $0.31 per therm. After adding transportation, load management, and DGS service fees, the per unit rate increases to range of $0.38 to $0.56 per therm, with an average of $0.44 per therm. A breakdown of monthly natural gas costs per process is provided in Figure 3-9.

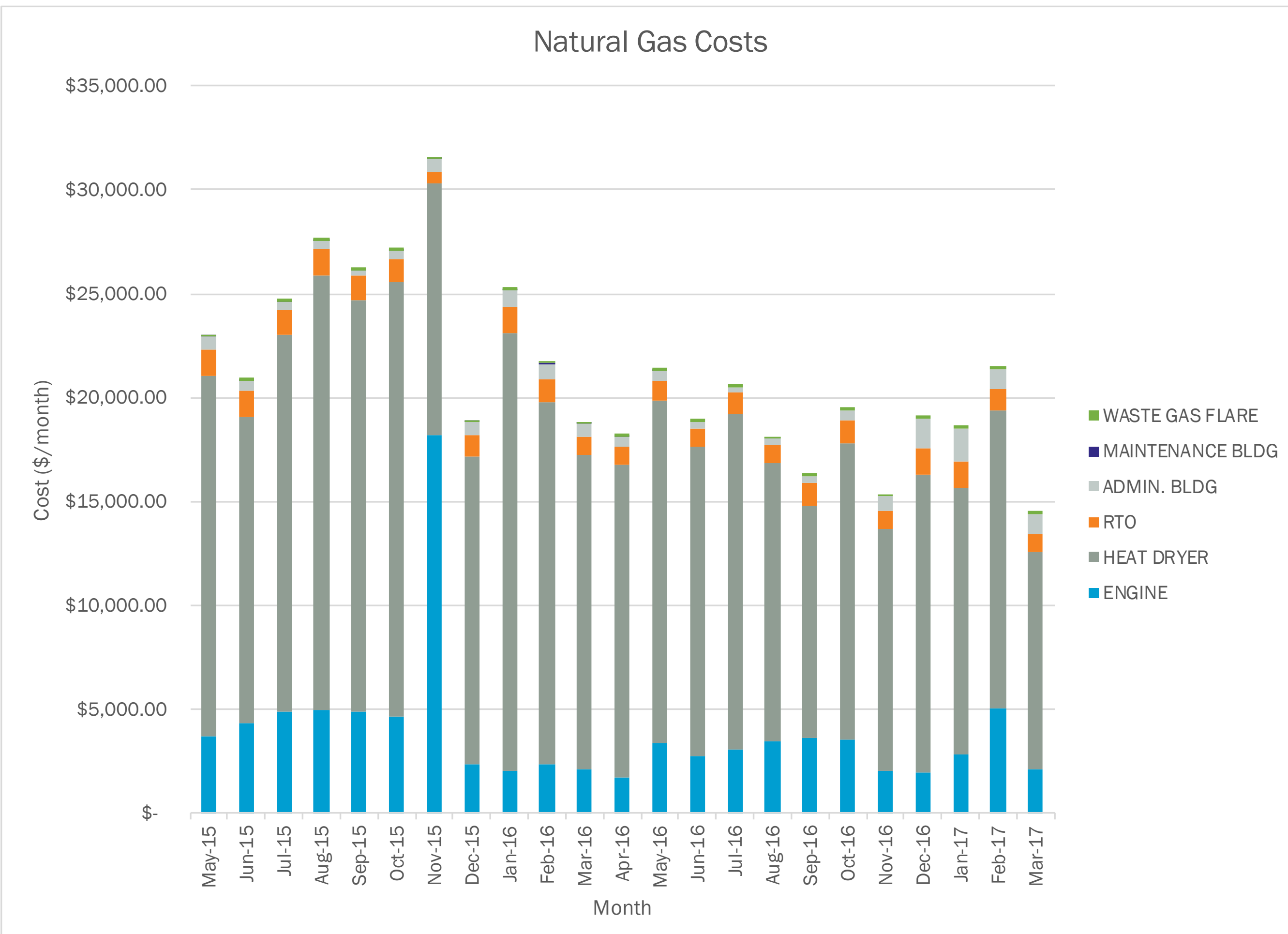

Figure 3-9. Natural gas costs per process/location at EWPCF

EWA's average cost of natural gas of $0.44 per therm through a separate natural gas procurement mechanism is substantially less than the alternative of at least $0.62 per therm through SDG&E's GN-3 natural gas rate schedule.

3.4 Heat Production and Use

Heat is produced at the plant via the engines and solids dryer. A portion of the heat produced by the engine is transferred to the plant's hot water loop and is utilized by the anaerobic digesters and an absorption chiller. The plant intends on transitioning from the absorption chiller to a conventional heating, ventilation, and air conditioning system; therefore, these demands will not be accounted for in future baseline heat demand. Engine exhaust heat that is not recovered to the plant's hot water loop is wasted to the plant's effluent and excess heat produced by the solids dryer is wasted to atmosphere as hot exhaust.

Available heat that can be recovered from the engine is estimated to be 40 percent of the fuel input for both jacket water recovery and exhaust recovery since historical data was not provided. With two 750 kW engines running at full output, approximately 6.0 million MMbtu/hour can be recovered. Currently, there is no method for capturing and utilizing waste heat from the RTO and all of the heat is wasted to the atmosphere as exhaust.

The baseline heat production and usage summarized in Table 3-4. Digester heat demand is based on an estimate from EWA's 2011 Energy and Emissions Strategic Plan.

Table 3-4. Heat Production and Usage

	Production, MMBtu/hr	Usage, MMBtu/hr
Engines	6.0	N/A
Dryer/RTO	1.4	N/A
Digesters	N/A	1.2
Total	7.4	1.2

Section 4: Future Conditions

Recently, the PMP determined the projected solids loading to EWPCF utilizing population growth projections as a means of determining future flows and loads as well as the historical trends method. Annual growth was provided by San Diego Association of Governments for use in the PMP. The projections were then incorporated as the influent loading and modeled through BIOWIN to obtain the WAS and PS loadings to the digesters. As part of Task 1, Brown and Caldwell reviewed EWPCF's historical data, comparing it to the PMP. This section will review the projected solids flows and loads. Furthermore, this section will review the projected energy demand and production, biogas production, natural gas use, and heat production based on estimated future loads. Finally, Brown and Caldwell will present the peaking factors that will be used for future analysis and design.

4.1 Solids Flows and Loads

With aggressive water conservation efforts in California, projecting flows in a wastewater treatment plant can be challenging. Solids loading to the facility, however, can be estimated as it scales with population growth. In that regard, Brown and Caldwell projected solids loads utilizing linear interpolation. The current loads determined in the mass balance and the growth rate from the PMP were used to create a linear expression. Table 4-1 summarizes the projected loads determined by Brown and Caldwell for 2020, 2030, and 2040. Table 4-2 summarizes the flows associated with the annual average solids loadings. Figure 4-1 compares the solids projection curve from the PMP to the one developed in this study. The loads shown here for current conditions are based on the calibrated mass balance presented in Section 2, They are higher than the loads projected in the PMP because influent loadings to the plant were likely underestimated in the PMP due to the use of non-representative grab samples. A rate of increase was applied to the 2017 loads determined by using the calibrated mass balance, on par with the rate used in the PMP, per EWA's direction. The projection rate used in the PMP was based on applying an annual population growth rate of 0.74 percent to the influent flow and modeling the subsequent solids production rates.

Table 4-1. Projected loads for PS and WAS

	Current	2020	2030	2040
PS, ppd	47,500	50,600	60,800	71,100
WAS, ppd	29,400	31,600	39,000	46,300

Table 4-2. Projected Flows for PS and WAS

	Current	2020	2030	2040
PS, MGD[1]	0.13	0.14	0.17	0.20
WAS, MGD[2]	0.71	0.76	0.94	1.11

[1] *PS assumes a total solids content of 4.3 percent*

[2] *WAS assumes a total solids content of 0.5 percent*

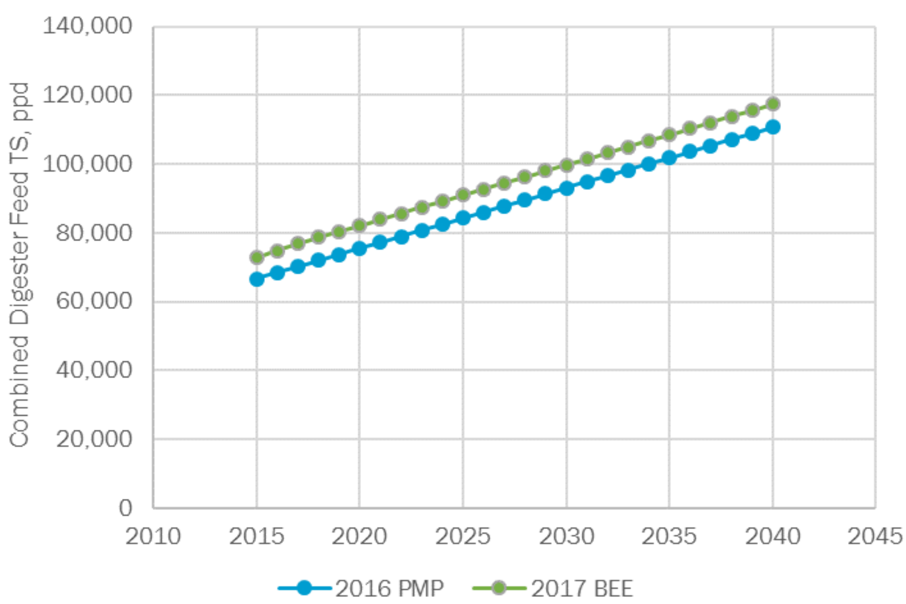

Figure 4-1. Solids projections determined from the 2016 PMP and 2017 BEE Plan

To project the energy and gas use and production, the projected PS and WAS were used to determine digester feed. Primary sludge remained as is at 4.3 percent solids. The WAS was thickened in the DAF at an assumed 95 percent capture rate. Finally, the FOG was assumed to be the same as the current load. These values are summarized in Table 4-3.

Table 4-3. Projected Solids Feed to the Digester

	Current	2020	2030	2040
PS, ppd	47,500	49,800	57,500	65,200
TWAS, ppd	27,900	29,900	36,600	43,200
FOG, ppd	4,000	4,000	4,000	4,000
Combined Digester solids load, ppd	79,400	83,700	98,100	112,400

4.2 Energy Production and Use

Based on the analysis of existing energy usage, 79 percent of the power consumed at the plant is dependent on flow and administrative uses, with 21 percent of the total energy use related to solids loading. As the solids loading projections at the plant increase, so too will the percentage of total energy associated with solids treatment. Energy projections are summarized in Table 4-4. The projected energy demands for each decade are also plotted on Figure 4-2 alongside the historical data presented earlier.

Table 4-4. Projected Energy Demand

	Current	2020	2030	2040
MWh/year	16,000	16,000	16,600	17,200
kWh/day	44,000	43,900	45,500	47,100

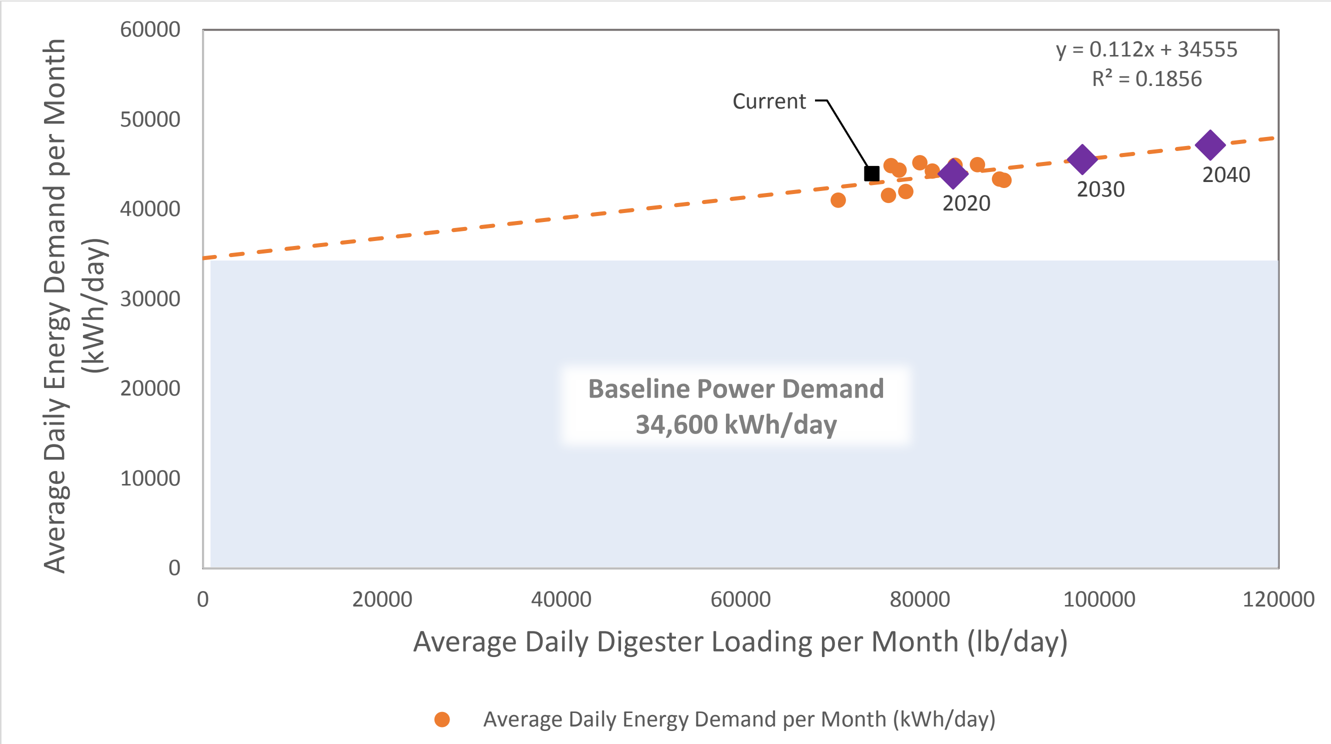

Figure 4-2. Projected Daily Energy Demand for 2020, 2030, and 2040

Until a decision has been made regarding EWA's request to modify the air permit to allow for the operation of three engines, it is assumed that the plant will continue to operate the engines as they do currently. Therefore, the baseline and future projections assume 1,500 kW of continuous engine output.

4.3 Biogas Production and Use

Biogas projections are expected to increase at a proportional rate based on the solids projections—for every pound of VS destroyed in the digesters, an additional 18 cubic feet of biogas will be produced, which is consistent with the historical data. A VSR of 60 percent was assumed in the projections, which aligns with the current biogas meter data. The biogas projections are summarized in Table 4-5.

Table 4-5. Projected Biogas Production

	Current	2020	2030	2040
scfm	501	544	703	766
therms/year	1,581,000	1,666,000	1,951,000	2,235,000

Biogas can be used in the IC engines to generate enough power to meet the plant's demands; however, this is pending EWA's August 2017 request to revise the air permit for operation of three IC engines. Until a decision has been reached regarding the permit modification, it is assumed the engines will run on biogas, with the remainder of gas used in the solids dryer. See Section 4.4 for biogas use in the heat dryer and RTO.

4.4 Natural Gas Use

Natural gas and digester gas use in the heat dryer and RTO is expected to increase as solids loading to the digesters increase. Based on the relationship developed between the two in Section 3.3.2, projected gas demands for 2020, 2030, and 2040 are 71,200, 83,500, and 95,700 MMBtu per year, respectively. Use in the engine will vary depending on the quantity of biogas available as solids loading projections increase and depending if the plant can operate a third engine on biogas. Therefore, use of additional natural gas as engine fuel is not included in the projected values noted previously. The administration and maintenance buildings and pilot flare are expected to remain constant and are not flow dependent.

4.5 Heat Production and Use

Heat production is expected to remain constant in the engines since operating conditions are assumed to match the existing baseline. Heat production in the solids dryer and RTO is expected to increase proportional to the increased solids loading to the dryer presented in Section 4.1. Likewise, digester heating projections are scaled proportionally to the projected flows for PS, TWAS, and FOG to the digesters in referenced in Section 4.1. These projections are conservative in that roughly 20 percent of the heat demand is typically lost through the digester shell, with about 80 percent used to warm-up the incoming sludge. Theoretically, shell losses should remain constant and only sludge heating projections would increase. A summary of these heat projections is summarized in Table 4-6.

Table 4-6. Heat Production and Usage Projections in MMBtu/hr

	Baseline		2020		2030		2040	
	Production	Usage	Production	Usage	Production	Usage	Production	Usage
Engines	6.0	N/A	6.0	N/A	6.0	N/A	6.0	N/A
Dryer/RTO	1.4	N/A	1.49	N/A	1.80	N/A	2.11	N/A
Digesters	N/A	1.2	N/A	1.28	N/A	1.55	N/A	1.81
Total	**7.4**	**1.2**	**7.49**	**1.28**	**7.80**	**1.55**	**8.11**	**1.81**

4.6 Peaking Factors

In addition to determination of the flows and loads projections, the solids projection peaking factors were established. Sufficient data were unavailable to accurately determine the solids peaking factors as total and VS are only analyzed weekly. Brown and Caldwell will use the peaking factors previously determined in the PMP for peak month and peak day. Peak 14 day and Peak 7 day were determined based on historical data and engineering judgment.

Table 4-7. Summary of Peaking Factors

	Peak Month[1]	Peak 14 day	Peak 7 day	Peak day[1]
PS	1.23	1.3	1.4	1.60
WAS	1.23	1.3	1.4	1.60
Combined Sludge	1.23	1.3	1.4	1.60

[1] *Values referenced from the PMP.*

4.7 Conclusions

The data discussed in this TM will be used as the basis for future work in the BEE Plan. This includes identifying capacity issues in the solids handling system. Solids and energy demand projections will be used to size corresponding process units in the development of alternatives under Task 7.

References

Carollo Engineers, *Process Master Plan for the Encina Water Pollution Control Facility*, Encina Wastewater Authority, Encina, CA. November 2016.

Black and Veatch, *Energy and Emission Strategic Plan,* Encina Wastewater Authority, Encina, CA. April 2011.

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Technical Memorandum

FINAL

Prepared for: Encina Wastewater Authority

Project Title: Biosolids Energy and Emissions Plan

Project No.: 150871.002.001

Technical Memorandum 2

Subject: Technology Evaluations for Biosolids Handling

Date: January 8, 2018

To: Scott McClelland, Assistant General Manager

From: Scott Lacy, Project Manager

Prepared by: ______________________________
Natalie Sierra, P.E., C 69751, Expiration June 30, 2018

Reviewed by: ______________________________
Perry Schafer, P.E., Vice President

Limitations:

This document was prepared solely for Encina Wastewater Authority in accordance with professional standards at the time the services were performed and in accordance with the contract between Encina Wastewater Authority and Brown and Caldwell dated June 28, 2017. This document is governed by the specific scope of work authorized by Encina Wastewater Authority; it is not intended to be relied upon by any other party except for regulatory authorities contemplated by the scope of work. We have relied on information or instructions provided by Encina Wastewater Authority and other parties and, unless otherwise expressly indicated, have made no independent investigation as to the validity, completeness, or accuracy of such information.

Acknowledgements

Significant contributions to this technical memorandum were made by:

- Tom Chapman, P.E.
- Tracy Chouinard
- Yinan Qi, P.E.

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List of Abbreviations

°F	degree(s) Fahrenheit
Advantek	Advantek Waste Management Services
BC	Brown and Caldwell
BEE	Biosolids Energy and Emissions
BFP	belt filter press
Btu	British thermal unit(s)
CASA	California Association of Sanitation Agencies
CDFA	California Department of Food and Agriculture
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
DAFT	dissolved air flotation thickener
DLD	digestion-lysis-digestion
DS	digested sludge
EPA	U.S. Environmental Protection Agency
EWA	Encina Wastewater Authority
EWPCF	Encina Water Pollution Control Facility
ft^3	cubic foot/feet
GET	GeoEnvironment Technologies
GHG	greenhouse gas
H_2S	hydrogen sulfide
HRT	hydraulic retention time
lb	pound(s)
MAD	mesophilic anaerobic digestion
mgd	million gallons per day
OLR	organic loading rate
O&M	operations and maintenance
PMP	Process Master Plan
ppm	part(s) per million
PS	primary sludge
RDT	rotary-drum thickener
RTO	regenerative thermal oxidizer
SRT	solids retention time
SWEET	Solids Water Energy Evaluation Tool
TAD	thermophilic anaerobic digestion
TCHP	thermo-chemical hydrolysis process
THP	thermal hydrolysis process
TIRE	Terminal Island Renewable Energy
TM	technical memorandum
TPAD	temperature-phased anaerobic digestion
TS	total solids
TWAS	thickened waste activated sludge
VAR	vector attraction reduction
VS	volatile solids
VSR	volatile solids reduction
WAS	waste activated sludge
WWTP	wastewater treatment plant

Executive Summary

The Encina Wastewater Authority (EWA) is developing a plan to expand solids-processing capabilities due to near-term capacity issues in the heat dryer at the Encina Water Pollution Control Facility (EWCPF), maximize resource recovery capabilities for EWA, and optimize the facility's energy production. This Technical Memorandum (TM) 2 describes the development of screening and evaluation criteria used to assess biosolids treatment technologies for solids handling.

Evaluation Process

Treatment technologies were evaluated for thickening, stabilization, dewatering, and post-dewatering processes. Technologies were selected for further evaluation through the three-step process described below.

Step 1: Biosolids End-Use Pre-Screening

Step 1 assessed viable end uses for a range of biosolids products. Technologies that passed the end-use filter are listed in Table ES-1. Technologies that did not generate viable beneficial uses in the Southern California region were eliminated from further consideration.

Table ES-1. Biosolids Treatment Technologies Selected for Evaluation

Thickening Technologies	Stabilization Technologies	Dewatering Technologies	Post-Dewatering Technologies
• Primary Clarifier • DAFT • RDT	• Mesophilic digestion • Mesophilic high-solids digestion • Acid/gas digestion • Staged digestion • Thermophilic digestion • TPAD • Enzymatic hydrolysis • Chemical hydrolysis • Lystek • THP: Class A • THP: Exelys-DLD • THP: SolidStream Cambi	• Centrifuge • BFP • Screw press • Volute press • Bucher press	• Drum dryer • Indirect dryer • Gasification • Pyrolysis • Partial solar drying • Deep-well injection • Dehydration • Incineration

BFP = belt filter press; DAFT = dissolved air flotation thickener; RDT = rotary drum thickener; THP = thermal hydrolysis process; TPAD = temperature-phased anaerobic digestion.

Step 2: Fatal-Flaw Screening

Step 2 involved the development of fatal-flaw criteria, for which a technology would pass or fail. Treatment technologies had to meet the following fatal-flaw criteria to be considered for further evaluation:

- There must be at least one full-scale installation of the technology at a wastewater treatment plant (WWTP) in North America
- There must be at least one successful installation of the technology at a facility of similar size to EWPCF to ensure compatibility

- The technology must be accommodated within EWPCF's limited available footprint
- The technology must be capable of being integrated into the existing treatment infra-structure

Step 3: Ranking of Screened Technologies

EWA previously evaluated thickening technologies in its Process Master Plan (PMP). Thus, EWPCF's current thickening (primary clarifiers for primary sludge [PS] and dissolved air flotation units for waste activated sludge [WAS]), and the recommended thickening process from the PMP (rotary-drum thickeners) were all advanced without further evaluation by the Brown and Caldwell (BC) team.

Stabilization and dewatering technologies that passed the fatal-flaw screening were further assessed using the evaluation criteria listed in Table ES-2, which were developed to reflect EWA's values and project goals. The pre-screened technologies were ranked based on these criteria in a workshop with EWA staff, held on August 16, 2017.

Table ES-2. Biosolids Treatment Technologies Evaluation Criteria

Criterion	Description
End-use market compatibility	• Onsite technology directly produces one of the recommended product alternatives • Alternatively, onsite technology product compatible with product alternatives
Proven technology performance	• Proven and reliable technology with same configuration intended at EWCPF • Long-term successful operating track record
Minimize life-cycle costs	• Qualitative metric of program cost • Capital and O&M costs based on existing EWA data or similar experience at other WWTPs • Potential revenues from sales • Product/market geographic proximity
Energy/resource recovery	• Biogas production increased through advanced digestion • Co-digestion of organic waste supported • Renewable energy recovered • Biosolids product beneficially reused
O&M impacts	• Impacts to existing WWTP O&M staff levels • Complexity of new technology O&M and control systems • Reliability of new technology (potential downtime) • Minimal impacts to WWTP safety
Environmental impacts	• Impacts to carbon footprint and air permitting
Community and stake-holder impacts	• Minimal nuisance impacts such as dust, odors, vectors, aesthetics, noise, and traffic • Impacts to partner agency issues/values, and local planning codes and requirements
Project site compatibility	• Compatibility of technology with available WWTP footprint • Incorporation into existing treatment process

O&M = operations and maintenance

Stabilization Technologies. Thermophilic digestion scored the highest, followed by mesophilic digestion and Class A thermal hydrolysis process (THP). Thermophilic digestion yields a dewatered Class B cake that can be beneficially used in agriculture in Arizona or sent to regional compost facilities for further processing, and has proven long-term performance records at WWTPs of various sizes. Thermophilic digestion provides the greatest potential to minimize life-cycle costs through revenue generated by importing high-strength waste. Thermophilic digestion also delivers greater proportional gas yield than the other technologies as compared to the relatively modest increased energy demand.

Dewatering Technologies. Belt filter presses (BFPs) scored the highest, followed by centrifuges. The evaluated technologies scored similarly in three of the criteria: life-cycle costs, environmental impacts, and community and stakeholder impacts. Differentiating criteria in this technology category included end-use market compatibility, proven technology performance, operations and maintenance (O&M) impacts, and project
site compatibility. With respect to proven technology performance, BFPs and centrifuges are the most widely used dewatering technologies in the United States. With respect to end use, research suggests that low-shear dewatering processes, like BFPs, yield cake with lower odors than high-shear processes like centrifuges.

Implementation Considerations

Thermophilic digestion occupies essentially the same footprint as mesophilic digestion, which is the stabilization process currently used at EWPCF. More heat exchanger capacity would be needed for thermophilic digestion, which could be accomplished by replacing the existing units with taller, higher-capacity units.

Two thermophilic scenarios will be explored in the alternatives analysis phase: (1) a 15-day thermophilic process, which guarantees Class B quality, but is limited by the ability to receive high-strength waste based on hydraulic capacity, and (2) a 10-day process, which allows EWA to receive greater quantities of high-strength waste. A new receiving station could be constructed to accommodate the increased quantities of waste.

One of the major questions to be addressed is whether a second thermal dryer is necessary to meet EWA's goals. As the existing building is space-constrained, a new building may need to be constructed to accommodate a second dryer, although efforts are underway to identify building modification alternatives. Ultimately, in the event construction of a new building was deemed desirable, the BC team prepared preliminary layouts for the second dryer that require demolition of the existing dissolved air flotation thickeners (DAFTs). Thus, if a second thermal dryer is required, thickening upgrades would need to be performed prior to the installation of the second dryer.

Next Steps

The biosolids treatment technologies selected through this screening process will be included in end-to-end project alternatives to expand solids-processing capabilities at EWCPF. Technology combinations, shown in Figure ES-1, will be combined with the results of Tasks 3, 4, and 5 to create end-to-end alternatives for further analysis. The three stabilization alternatives—mesophilic digestion, thermophilic digestion, and Class A THP—will each be evaluated with and without a second thermal dryer. Development of end-to-end alternatives will be performed in cooperation with EWA staff prior to analysis.

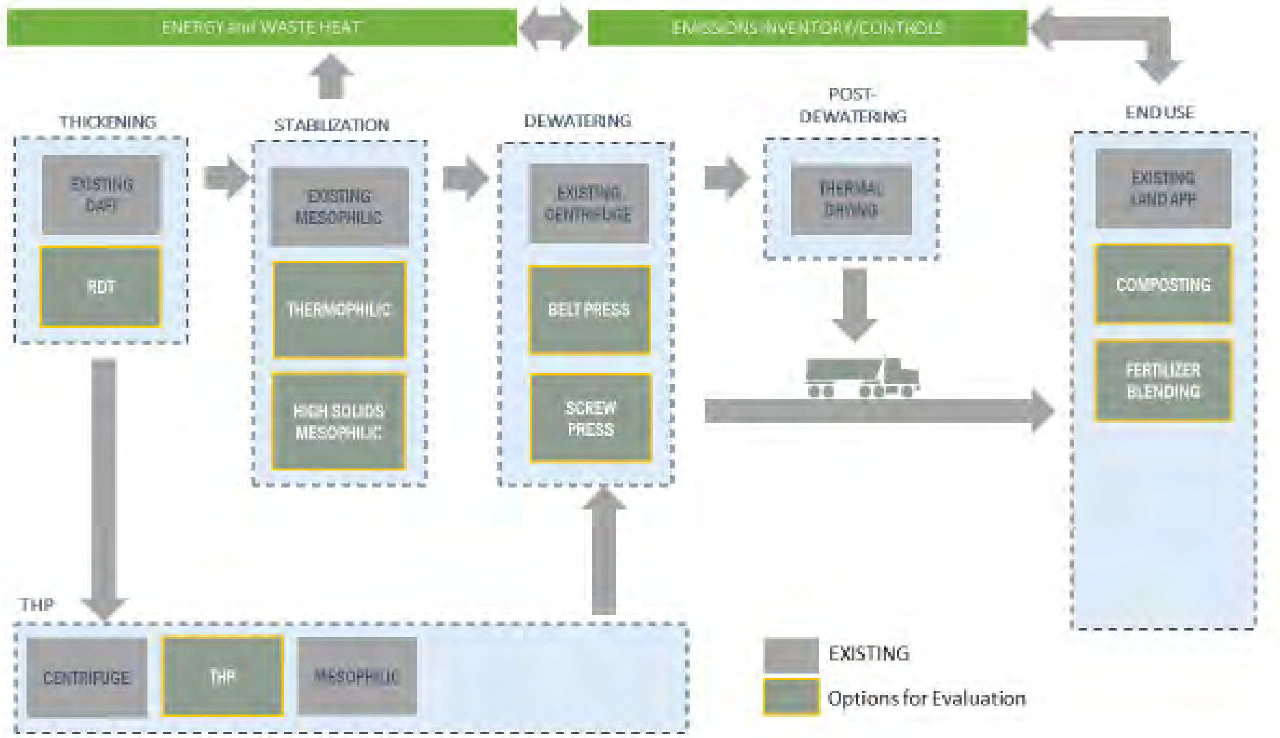

Figure ES-1. Biosolids treatment technology options for EWCPF end-to-end project alternatives.

Section 1: Introduction

The EWA is developing a Biosolids Energy and Emissions (BEE) Plan, which will serve to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed PMP. The BEE Plan has several goals:

- Provide a comprehensive analysis of all project elements, including solids treatment, waste heat handling, gas processing, and energy generation and use
- Address capacity limitations in the solids and gas handling processes, energy and emissions at the EWPCF
- Assess which alternative is likely to be the most cost-effective and sustainable solutions for EWA
- Move the EWPCF toward greater energy efficiency and independence
- Reduce greenhouse gas (GHG) emissions

The outcome of this process is an implementable plan resulting in capital improvements to expand system capacities as needed and appropriate, maximize resource recovery capabilities for EWA, and optimize energy production. Under Task 2 of the BEE, the BC team developed a methodology for screening and evaluating technologies for solids handling. Technologies were evaluated for thickening, stabilization, dewatering, and post-dewatering. Stabilization technologies evaluated included alternatives for production of Class A and Class B biosolids. Recommended technologies selected under this task will be advanced for further analysis and will be combined with gas use, energy production, and waste heat alternatives developed under Tasks 3 through 5. This TM describes the evaluation methodology for solids processing and biosolids technologies, the technologies evaluated, and how these technologies were screened and ranked. Screening and ranking of technologies was performed in a workshop with EWA staff, held on August 16, 2017. Meeting minutes from this workshop are provided as Attachment A.

This TM is preceded by TM 1, which addressed the baseline energy profiles and projections, established a mass balance for the solids-handling system, and defined solids projections which are used in the PMP. Calculations performed and discussed in TM 2 are based on the values defined in TM 1.

Section 2: Evaluation Methodology for Biosolids Technologies

The BC team developed a three-part evaluation process for assessing solids processing technologies. The first two parts, described in Sections 2.1.2 and 2.1.3, were performed under Task 2. Use of the Solids Water Energy Evaluation Tool (SWEET) will be performed under Task 7.

The approach to evaluating solids technologies involved a three-step process outlined here:

- First, a pre-screening step incorporating biosolids end-use considerations was performed. Biosolids end use in California is highly regulated and can be complicated. Thus, it is important to incorporate considerations for those technologies that generate a desirable end product that can be beneficially used. These end-use considerations eliminated certain technologies from consideration.
- Next, the selected technologies from the pre-screening step were then evaluated through a fatal-flaw analysis.
- Finally, those technologies that passed the fatal-flaw test were evaluated and ranked using evaluation criteria developed in conjunction with EWA.

These three steps are described in more detail in the following sections.

2.1 Role of Biosolids End Use

By starting with biosolids end use, the BC team evaluated only those technologies that would generate a product suitable for beneficial use in the region. Beneficial use generally refers to those end uses that avoid landfill disposition and provide a benefit, such as soil conditioning or carbon sequestration. While use of biosolids in alternative daily cover has historically been considered a beneficial use, CalRecycle has stated that it intends to phase out this definition in support of overall policies encouraging the diversion of organics from landfills. Other typical beneficial uses include:

- **Cement kilns:** Biosolids have been used in cement plants to produce clinker, the main component of cement, which is an energy-intensive operation. Biosolids have recoverable calorific value that can be used as fuel in making cement—replacing a portion of conventional fossil fuels—if they meet industry specifications. While biosolids have a lower heating value than coal, and generate more ash per British thermal unit (Btu) than coal, biosolids also contain useful minerals that are incorporated into the clinker to make cement.
- **Land reclamation:** Across the United States, biosolids have been used to reclaim marginal lands including abandoned mines and fire ravaged lands. In this particular end use, large quantities of biosolids are used for a limited period (no more than a few years) to remediate a given parcel or parcels of land. In California, the U.S. Environmental Protection Agency (EPA) Region IX has expressed interest in the use of Class A biosolids to remediate damaged lands.
- **Bulk agriculture:** Use of biosolids in land application is a common and well-established practice in California; more than 60 percent of biosolids generated in the state are managed this way. Land application provides beneficial use of biosolids, applied at agronomic rates as a soil amendment in agriculture.
- **Bulk horticulture and landscaping:** Class A biosolids can be used in horticultural activities such as landscaping and nursery production (e.g., sod production, establishment of field beds, preparing container mixes for specialty plants, etc.). Products grown in these applications generally have a higher value than those in bulk agriculture and include ornamental flowers, trees, and shrubs.

- **Fertilizer blending:** Commercial fertilizer blenders enhance dried biosolids with micro- and macro-nutrients and then package and market the blend for sale in retail outlets. Blending requires a hard, size-graded pellet or granule product of the type that is typically produced by drum dryer systems. Fertilizers have additional regulatory oversight and requirements by the California Department of Food and Agriculture (CDFA).
- **Soil blending:** Commercial soil blenders mix native soils, organics, and other ingredients such as sand to produce custom soil blends for a variety of non-agricultural uses, such as in construction, landscaping, and development of green infrastructure. Using dewatered Class A biosolids as an ingredient in the production of blended landscape soils is a newer biosolids management technique.
- **Local distribution:** Some utilities have been able to successfully distribute Class A biosolids products directly to residents and/or to local users (e.g., road and highway departments, establishment of street trees). This typically requires a value-added Class A product, such as granules, compost, or soil blend, that shares characteristics with commercially available amendments rather than dewatered cake.

Based on market research performed recently by the BC team, EWA's size (i.e. capacity, solids production) makes it difficult to access cement kilns, as EWA has experienced in the past, which require larger volumes of biosolids for use in onsite energy generation. Land reclamation is a practice more common in the northeastern United States, and typically requires large volumes of biosolids over a relatively short period. Bulk agriculture is the primary end use for California biosolids, although it is important to note that some local county ordinances restrict the use of biosolids. Thus, many Southern California wastewater agencies, including EWA, send their biosolids to western Arizona for agricultural land application. Class B biosolids cannot be land-applied in Southern California, while some counties do permit land application of Class A biosolids. A map of the county ordinances, created by the California Association of Sanitation Agencies (CASA), is provided in Attachment B.

Bulk horticulture and fertilizer blending have both been destinations for EWA's dried granules. Bulk horticulture has also absorbed some Class A compost generated by regional composting facilities. Soil blending is a well-established practice, but experience with using biosolids in blends is limited to a few facilities using Class A compost generated by the Inland Empire Regional Compost Facility.

Viable beneficial uses were paired with biosolids products, which in turn were linked to onsite solids-handling processes. The exception is offsite composting—capacity in regional composting facilities exists for the offsite conversion of Class B cake to Class A compost. Stabilization processes were defined generally (e.g., Class A digestion) and, in some cases, several processes will yield a given product, as discussed in greater detail in Section 3.2. These stabilization processes form the starting point for the biosolids technology evaluation. Table 2-1 summarizes the relationship between stabilization processes, relevant post-dewatering processes, products, and beneficial uses.

Table 2-1. Paired Stabilization Processes, Products, and Associated Beneficial Uses

Stabilization Process	Post-Dewatering Process	Resulting Product	Associated Beneficial Use(s)
Class B digestion	None	Class B cake	Bulk agriculture (Arizona only)
Class B digestion	Class A composting (off site)	Class A compost	Bulk agriculture Bulk horticulture Soil blending Local distribution
Class B digestion	Thermal drying	Class A granules	Bulk agriculture Bulk horticulture Fertilizer blending Soil blending Local distribution
Class A digestion	None	Class A cake	Bulk agriculture Soil blending Land reclamation
Class A THP	None	Class A THP cake	Bulk agriculture Bulk horticulture (with aging) Soil blending Land reclamation

2.2 Fatal-Flaw Screening

Beginning with the end use, acceptable biosolids technologies capable of generating products for beneficial use were identified. These technologies were then examined through a fatal-flaw filter, which was applied uniformly across all technologies: biosolids, alternative power production, and waste heat use. The four criteria below were developed in conjunction with EWA staff:

- At least one successful North American installation of technology: There must be at least one full-scale installation of the technology at a WWTP in North America.
- At least one successful installation in a facility of similar size: The technology should be sufficiently developed that it is applicable at a facility of comparable size to EWPCF to ensure compatibility.
- Available space: The technology must be accommodated within the limited available footprint at EWPCF.
- Compatibility with plant site and any existing equipment: The technology must be capable of being integrated into the existing WWTP infrastructure.

A discussion of how the fatal-flaw criteria were applied to individual treatment technologies is provided in Section 3.

2.3 Evaluation Criteria Development and Ranking

For those technologies that passed the fatal-flaw filter, further evaluation and ranking was performed. The BC team worked with EWA staff to develop a series of evaluation criteria that reflect the project goals, EWA's values, and EWA's general operational practices. Criteria weights were assigned in a workshop with EWA staff. Criteria are presented in Table 2-2. These criteria were applicable for stabilization technologies. The "energy/resource recovery" criterion was not applicable for the dewatering technologies, which results in a different weighting system. Table 2-3 presents the two different weights associated with the stabilization and dewatering technologies. Evaluation of individual biosolids technologies is discussed in Section 4.

Table 2-2. Biosolids Technology Evaluation Criteria		
Criterion	**Description**	**Scoring Description**
End-use market compatibility	Onsite technology directly produces one of the recommended product alternatives Alternatively, onsite technology product is compatible with product alternatives	**Low-score** indicates technology product that has not been identified as part of the product list and is not compatible with the product list **High-score** indicates technology product that is compatible with Class B cake, Class A cake, Class A THP cake, and dried Class A pellet
Proven technology performance	Proven and reliable technology with same configuration intended at EWPCF Long, successful operating track record	**Low-score** indicates no successful large-scale operating installations in North America or Europe, no successful demonstration-scale installations in North America or Europe, and unknown safety or reliability record **High-score** indicates more than one successful operating installation in North America or Europe, more than one operating installation at a WWTP of at least 40 mgd in North America or Europe, a track record duration > 5 years, and vendors in western United States
Minimize life-cycle costs	Qualitative metric of program cost Capital and O&M costs based on existing EWA data or similar experience at other WWTPs Potential revenues from sales Product/market geographic proximity	**Low-score** indicates high capital cost to build onsite facilities, high O&M costs, expensive end-use market, and high transportation costs **High-score** indicates low capital cost to build onsite facilities, low O&M costs, potential product revenue, and product destination within 100 miles
Energy/resource recovery	Increases biogas production through advanced digestion Supports co-digestion of organic waste Recovery of renewable energy Beneficial use of biosolids product	**Low-score** indicates high energy requirement for onsite technology, no increase in biogas production, technology does not recover energy as biogas, no recovery of renewable energy in biosolids, and no biosolids resource recovery **High-score** indicates a higher biogas production, compatible with co-digestion of organic waste, and biosolids resource recovery
O&M impacts	Impacts to existing WWTP O&M staff levels Complexity of new technology O&M and control systems Reliability of new technology (potential downtime) Minimal impacts to WWTP safety	**Low-score** indicates more O&M time required, complex mechanical and control systems required compared with existing WWTP facilities, potential equipment downtime, and new chemicals or hazards **High-score** indicates reduction in O&M staff time required, new technology is simple to operate and maintain, reliable with minimal downtime, and no new chemicals or hazards
Environmental impacts	Impacts to carbon footprint and air permitting	**Low-score** indicates high carbon footprint for technology, high travel distance to end use, difficult to treat sidestreams, and new permitting for environmental regulatory requirements **High-score** indicates low carbon footprint for technology, low travel distance to end use, minimal sidestream generation or impacts, and no additional permitting for environmental regulatory requirements

Table 2-2. Biosolids Technology Evaluation Criteria		
Criterion	**Description**	**Scoring Description**
Community and stakeholder impacts	Minimize nuisance impacts such as dust, odors, vectors, aesthetics, noise and traffic Assess impacts to partner agency issues/values as well as local planning codes and requirements	**Low-score** indicates that nuisance factors for onsite technology are difficult to mitigate **High-score** indicates that nuisance factors can be mitigated at WWTP site
Project site compatibility	Assess compatibility of technology with available WWTP footprint Incorporation into existing treatment process	**Low-score** indicates lack of site space for new facilities, requires abandonment of existing facilities, and difficult integration with existing WWTP **High-score** indicates available footprint for new facilities and maintains space for future facilities, and ease of integration with existing processes and facilities

O&M = operations and maintenance

Table 2-3. Biosolids Technology Evaluation Criteria Weighting Values		
Criterion	**Stabilization Weight**	**Dewatering Weight**
End-use market compatibility	15%	15%
Proven technology performance	15%	25%
Minimize life-cycle costs	10%	20%
Energy/resource recovery	20%	N/A
O&M impacts	10%	15%
Environmental impacts	10%	5%
Community and stakeholder impacts	10%	5%
Project site compatibility	10%	15%

2.4 Solids-Water-Energy-Evaluation Tool

Under Task 7, biosolids treatment technologies will be combined with biosolids beneficial use, alternative power production, and waste heat technologies to create holistic end-to-end alternatives. BC's SWEET will be used to efficiently evaluate the feasibility and energy and economic profiles of brainstormed alternatives, and compare those alternatives with the current program to provide a baseline for measurement. SWEET tracks volatile solids (VS), inert solids, and water through potential process alternatives and considers energy required to power/heat those processes and forecast energy production and material recovery. It also allows comparison of energy balances with integration of multiple feedstocks, and estimation of the carbon footprint of each alternative. Two notable advantages of SWEET include its ability to evaluate alternatives in real time during workshops and its transparency of all the factors used.

Key model outputs to facilitate alternative selection included:

- Capital costs
- Operations and maintenance (O&M) costs
- Economic net present value

Another advantage of SWEET is that it allows for an iterative evaluation process; if aspects of certain alternatives appear to provide strong benefits; these aspects can be incorporated to create an optimized set of alternatives for evaluation. In this evaluation, the iterative evaluation is used to develop the most advantageous program for EWA.

Section 3: Identification of Biosolids Technologies

Table 3-1 contains a general description of the technologies needed to generate the desired end products. Specific thickening, digestion, dewatering, and post-dewatering technologies identified in

Workshop 2 with EWA staff are summarized in Table 3-1. Descriptions of each of the identified technologies follow in this section. Some technologies were eliminated at the outset. Although a number of technologies could be accommodated at the site, EWA staff were comfortable with the recommendation from the PMP to install rotary-drum thickeners (RDTs) for the thickening process. In the alternatives evaluation, these will be compared against the currently installed thickening equipment. With respect to stabilization processes, several processes were eliminated from the outset. Lime stabilization was briefly considered but produces an odorous product in a region where agricultural demand for lime is low. In addition, it would require installation of new equipment at EWPCF, including appropriate odor control. Aerobic digestion was also considered but is not compatible with the size of EWPCF or the energy goals of EWA.

Table 3-1. Biosolids Treatment Technologies Selected for Evaluation

Thickening Technologies	Stabilization Technologies	Dewatering Technologies	Post-Dewatering Technologies
Primary clarifier	Mesophilic digestion	Centrifuge	Drum dryer
DAFT	Mesophilic high-solids digestion	BFP	Indirect dryer
RDT	Acid/gas digestion	Screw press	Gasification
	Staged digestion	Volute press	Pyrolysis
	Thermophilic digestion	Bucher press	Partial solar drying
	TPAD		Deep-well injection
	Enzymatic hydrolysis		Dehydration
	Thermo-chemical hydrolysis		Incineration
	Lystek		
	Class A THP		
	Exelys THP: DLD		
	THP: SolidStream Cambi		

BFP = belt filter press; DAFT = dissolved air flotation thickener; TPAD = temperature-phased anaerobic digestion

3.1 Thickening Technologies

Selection of a thickening process is critical to the design and performance of downstream digestion. The more efficient the thickening process is, the more concentrated the solids being sent to digestion are, allowing for better digestion performance. Thickening technologies were evaluated for the thickening of PS, waste activated sludge (WAS), and a combination of the two. Currently EWA operates sludge thickening at EWPCF using primary clarifier thickening for PS as well as a dissolved air flotation thickener (DAFT) process for WAS; details of these technologies are also included below.

3.1.1 Primary Clarifier Thickening

In primary clarifier thickening, sludge settles by gravity in the primary clarifier and is pumped out to the digester feed system via a dedicated line. Historical use of this process shows an improvement in digester performance as compared to sending thin PS to digestion. EWA typically achieves 4.1 percent total solids (TS) in the PS using primary clarifier thickening. The process is easy to operate and is space-efficient, but does not achieve as high a TS content as some of the other processes detailed herein.

3.1.2 Dissolved Air Flotation Thickening

As mentioned above, DAFT is the current process used to thicken WAS at EWPCF. The DAFT process works by forming air bubbles in a tank to which suspended solids attach. The adhered solids float to the surface, where they can be removed with the aid of a skimming device. Polymer is often added as a coagulant aid. DAFTs have the advantage of being relatively simple to operate, and EWPCF typically achieves 5.6 percent TS from its DAFT process. While currently used only for WAS, DAFTs can be used to co-thicken PS and WAS if desired; however, operating in this configuration may generate more odors.

3.1.3 Rotary-Drum Thickening

RDTs feed sludge into a rotating perforated drum with a screw to carry sludge to allow water to separate from sludge material while solids are conveyed to a discharge point for piping. A polymer is typically added upstream of the RDT to encourage large solids flocs. Figure 3-1 shows a typical RDT system.

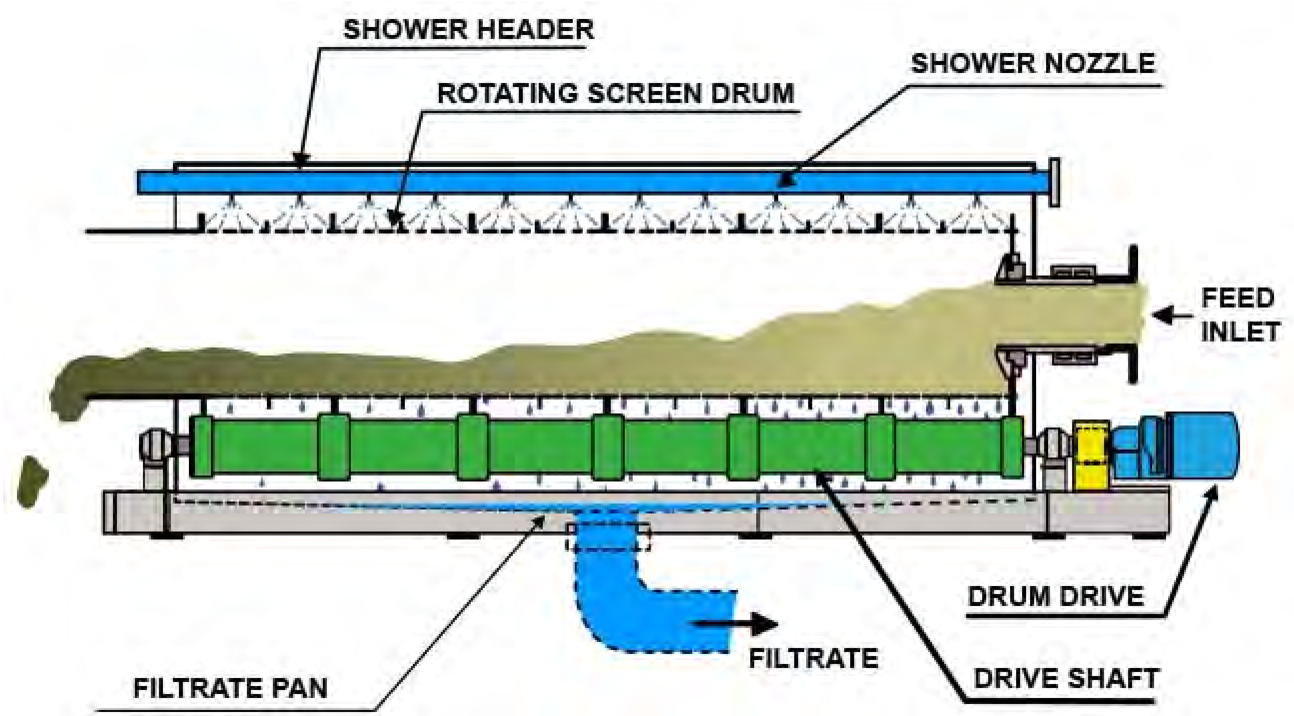

Figure 3-1. Rotary-drum thickener.

Source: http://www.fkcscrewpress.com/crst.html

Because of the enclosed system design, RDTs typically have low odor control requirements, require smaller footprint, are simple to operate, and have low capital and O&M costs as compared to other mechanical thickening equipment such as gravity belt thickeners and thickening centrifuges. The PMP evaluation noted that the O&M costs associated with RDTs are also lower than those associated with the existing thickening system. However, RDTs are also known to be sensitive to sludge feed concentrations and require a significant wash water demand.

3.2 Stabilization Technologies

Digestion is the core stabilization technology for the purpose of reducing pathogens, reducing vector attraction, and generally making a biosolids product capable of meeting regulatory requirements associated with beneficial use. Individual digestion technologies evaluated in this process are described below. As discussed previously, only anaerobic digestion technologies were considered in this evaluation.

3.2.1 Mesophilic Anaerobic Digestion

Mesophilic anaerobic digestion (MAD) is a conventional sludge stabilization process. MAD employs operating temperatures between 95 and 102 degrees Fahrenheit (°F) and solids are digested under anaerobic conditions. Typically, MAD systems are operated at a minimum hydraulic retention time (HRT) of 15 days, which, when requirements for vector attraction reduction (VAR) are met, guarantees Class B pathogen status for beneficial use. This stabilization process has the longest operational history of all the processes under consideration, with the most supporting operational data to date.

Although this alternative provides the major benefits of operational simplicity and a long history of operation, the process has its disadvantages when compared to newer, more aggressive technologies. While MAD operates efficiently, the degradation rates are relatively low when compared with other advanced digestion processes. This lower biological degradation rate manifests itself in terms of lower VS destruction, lower gas production, more tankage volume required, and additional mass of solids for disposal relative to the other processes evaluated. In addition, use of MAD allows for less available capacity for co-digestion substrates because of the inherently lower organic loading rate (OLR) associated with the process. As MAD is the current stabilization technology at EWPCF, it passed the fatal-flaw filter.

3.2.2 Mesophilic High-Solids Digestion

A high-solids MAD or recuperative thickening is a process that thickens digested sludge (DS) from the digester and returns it back to the digester, increasing solids retention time (SRT) and returning anaerobic bacteria to the digester to increase biological activity. Thickening processes include centrifuges, gravity belt thickeners, and DAFT.

The major benefit of this process is the increase in SRT, which means that more capacity is available in the digester. This is often beneficial when a tank is taken out of service for maintenance, or may prolong construction of future additional digesters. However, this process can be complex to operate, requires process equipment in addition to process equipment for the digester system, and requires additional polymer. Industry experience with this process is fairly limited; current installations are on digesters of much smaller volume than those at EWPCF. The BC team recommended that this process pass the fatal flaw filter, but only for installation on the smaller digesters at EWPCF (which would need to be rehabilitated for such an installation). If EWA chose to implement such an alternative, it would enable them to gain experience in operating a high-solids digestion system prior to installing it on the large digesters.

3.2.3 Staged Mesophilic Anaerobic Digestion

In a conventional MAD system, digesters are operated in parallel. In staged MAD, the digesters are operated in series. The first stage consists of heating and mixing the feed sludge to sufficiently stabilize the influent sludge. In this first stage, an HRT of 7 to 10 days is used but a higher OLR may be selected to reduce the overall footprint. The second stage receives, heats, and mixes sludge from the first stage, but operates at a lower HRT because the bulk of digestion takes place in the first stage.

The advantage of this process is significantly reduced short circuiting, which in turn improves VS reduction (VSR) and final product stability. Thus, higher-quality biosolids are typical when compared against a single-staged mesophilic system operated at an equivalent detention time, although in both cases, Class B biosolids are produced. Finally, a minor increase in gas production may be observed with this process. Despite these advantages, this alternative requires a larger overall footprint than conventional MAD and may require additional heating as compared to the current system. Given the limited available digestion footprint at EWPCF, this technology did not pass the fatal-flaw filter.

3.2.4 Acid-Gas Phase Digestion

Acid-gas phase digestion (also known as multi-phase or two-phase digestion) is a two-phase process in which two separate tanks are designed around different process goals, allowing the conditions in each tank to be optimized for the desired metabolic process. The first phase, the acid phase, is characterized by short HRT, typically 1 to 2 days, and low pH. Under these conditions, the acid-forming bacteria respire optimally, converting the particulate organics to volatile acids. The gas phase receives sludge from the acid phase, and has a longer HRT. The high level of volatile acids in the sludge supports a strong methanogen population.

As with conventional MAD, a total 15-day HRT is desirable in the acid-gas digestion process, and the sum of both the acid phase and the gas phase HRT are used to achieve this goal. However, most of the gasification of organics occurs in the second phase rather than the first. It is important to note that the acid phase sludges and gases are corrosive, and appropriate equipment and construction materials are required. Optimization of the fermentation stage is important for effective operation of acid-gas digestion. Gas from the acid phase includes carbon dioxide (CO_2), methane (CH_4), and hydrogen sulfide (H_2S), and is commonly connected to the digester gas system. If the gas phase is not connected to the gas system, extensive odor control may be required. Excessive retention times in the acid phase may increase odorous compounds, including H_2S. These compounds may impact the operational life or performance of gas utilization equipment and may generate odors at the flares. In addition, acid-gas digestion can be very challenging to operate correctly, despite its apparent similarities to MAD. For these reasons, acid-gas digestion did not pass the fatal-flaw filter.

3.2.5 Thermophilic Anaerobic Digestion

Thermophilic anaerobic digestion (TAD) is a means of enhancing digestion capacity at the facility through anaerobic digestion at thermophilic temperatures, ranging from 122 to 132°F. The high-temperature operation increases reaction rates and provides additional gas production, solids destruction, and increased pathogen inactivation. TAD can accommodate approximately double the OLR of MAD, up to 0.4-pound VS per cubic foot per day (lb-VS/ft^3-d).

Thermophilic digestion can be configured to generate Class A biosolids. This can be accomplished with batch tanks, for example, where the sludge is held for 24 hours at thermophilic temperatures (131°F or greater) to meet EPA requirements for Class A. Some wastewater treatment facilities, like the City of Los Angeles, have produced Class A biosolids using thermophilic digestion with limited-size batch tanks, which results in somewhat less time and temperature stipulated by the Class A criteria; however, additional sampling and testing of the biosolids is required to demonstrate Class A compliance in such instances. TAD would easily integrate within EWPCF and, as a well-proven technology, it passed the fatal-flaw filter.

3.2.6 Temperature-Phased Anaerobic Digestion

A temperature-phased anaerobic digestion (TPAD) system operates in two distinct temperature phases, digesting sludge in different tanks arranged in series. The first phase is the thermophilic phase, which typically operates at an HRT between 5 and 10 days. This is followed by a mesophilic phase typically operated between 6 and 15 days HRT. If Class B biosolids are desired, the TPAD system would be designed such that the combined retention time meets the 15-day HRT requirement. As with the TAD system, the OLR is approximately double MAD, at 0.4 lb-VS/ft^3-d, applied to the first-stage thermophilic digester. This high loading rate can allow for smaller digesters or fewer digesters to be constructed, reducing footprint relative to the overall system capacity, if the relevant criterion for total system HRT is met.

By phasing the digestion process through the thermophilic phase to the mesophilic phase, the advantages of thermophilic digestion are gained but carry an additional benefit of allowing the mesophilic phase to “polish” the volatile acid concentrations, improve VSR, and reduce odors. The thermophilic digestion process is typically characterized by high biogas production rates, high VS destruction (65 to 65 percent), and significantly enhanced pathogen kill. Essentially, most of the stabilization occurs in the thermophilic phase. In this phase because of the higher OLR and temperature, there are higher volatile acid and ammonia concentrations. When cooled and allowed to enter the mesophilic phase, these concentrations are polished, decreasing volatilized ammonia and other odorous compounds. Like TAD, TPAD can be configured to generate Class A biosolids. The footprint required for TPAD, however, cannot be accommodated within the available area of EWPCF, and therefore this technology did not pass the fatal-flaw filter.

3.2.7 Thermal Hydrolysis Process

THP is an anaerobic digestion pretreatment system that results in more efficient wastewater solids processing and energy production and, in certain configurations, achieves Class A biosolids. The three types of THP systems presented and screened are Class A THP, Exelys digestion-lysis-digestion (DLD), and SolidStream™ Cambi.

3.2.7.1 Class A THP

Class A THP is a mature technology in Europe and world-wide with full-scale facilities in service since 1995; the first installation in the United States (DC Water) has been operating since late 2014 and other U.S. installations are in the planning, design, and construction phases. There are two primary manufacturers of Class A THP – Cambi and Veolia. Class A THP uses medium-pressure steam to create high temperature and pressure conditions, which lyse bacterial cells and promote the release and solubilization of particulate organic material, making the feed solids more amenable to digestion. Figure 3-2 below depicts a typical process flow of the Cambi Class A THP system. THP can also be used in a WAS-only configuration, where it would generate Class B biosolids. This process will be discussed and evaluated in TM 4.

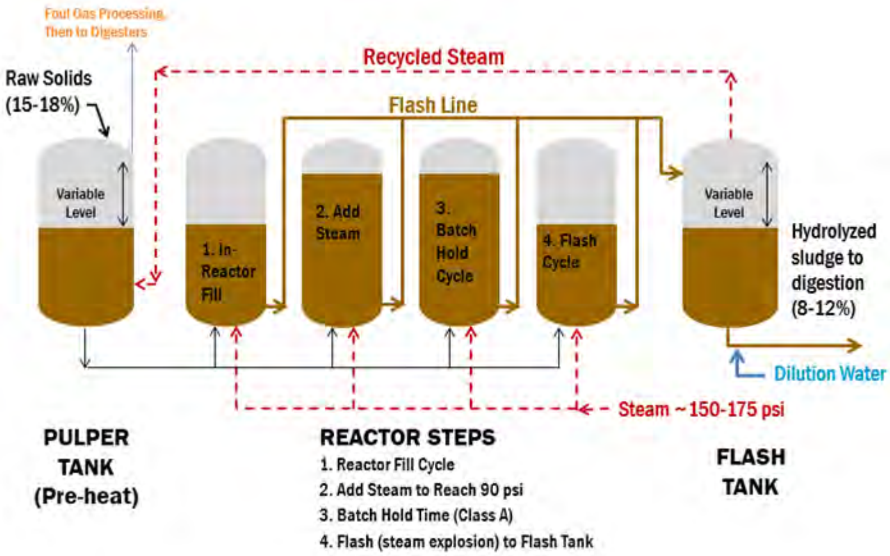

Figure 3-2. Cambi thermal hydrolysis process.

The vast majority of Class A THP systems have been implemented by Cambi. However, competitor THP systems have been installed in Europe, and Veolia's Biothelys system has been installed in the United Kingdom at a size comparable to EWPCF. THP systems can approximately double MAD OLRs because of the modified characteristic of the feedstocks. This more efficient use of digester volume reduces the number of digesters required. Ancillary buildings and equipment are required to operate a THP system, including steam boilers, pre-dewatering centrifuges, raw cake storage, and sludge cooling systems. While THP systems can reduce digester volume required, these ancillary systems impact total system cost, complexity, and footprint. Given that this technology is proven and can be integrated into the EWPCF foot-print, it passed the fatal-flaw filter.

3.2.7.2 Exelys Digestion-Lysis-Digestion

Exelys-DLD is a process developed by Veolia. While many THP systems use a batch process, Exelys uses a continuous flow reactor. In the DLD configuration, hydrolysis does not occur on the digester feed. Hydrolysis is placed between two digestion steps instead of prior to digestion, as shown in Figure 3-3. This configuration helps digestion by hydrolyzing solids that are resistant to digestion. The readily digested material has already been digested in the first digestion stage, leaving only the harder-to-digest organics. This material is now more digestible in the second-stage digester. Relative to MAD, this system would produce more biogas and destroy more solids. The process requires more digestion tankage than more common THP approaches and this makes it infeasible for EWA. In addition, Exelys-DLD does not have full-scale installations in North America. This technology thus failed the fatal-flaw filter.

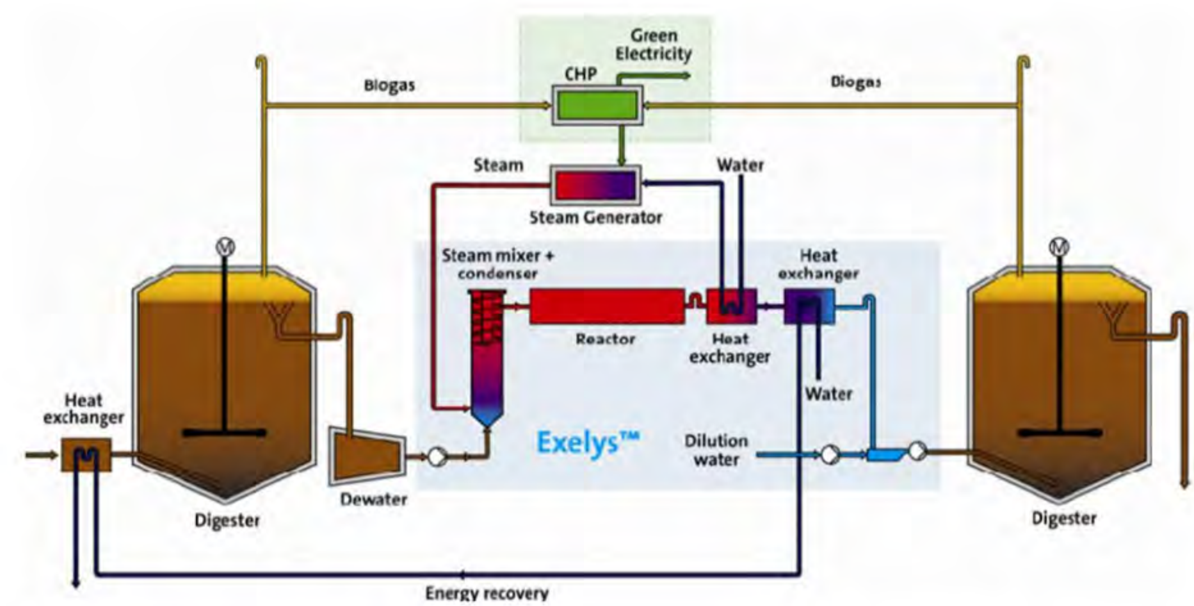

Figure 3-3. Exelys digestion-lysis-digestion process.

Source: Veoliawatertech.com

3.2.7.3 SolidStream Cambi

SolidStream Cambi is different from Cambi's traditional Class A THP in that it does not hydrolyze the solids prior to digestion. The sludge is digested in a digester, such as MAD, and then the DS is dewatered. Dewatered sludge enters the SolidStream system where it is hydrolyzed and final dewatered as a hot material. In this process, the dewaterability of the sludge is increased by increasing the temperature and pressure. This degrades the extracellular polymeric substances, which causes the release of more water from the sludge. Immediately following hydrolyzing, the solids are dewatered using a centrifuge without the addition of polymer. The centrate is fed to the digester and cake can be a Class A material. Figure 3-4 provides an overview of this process. The benefit of SolidStream Cambi is the increased dewaterability of the solids and the additional soluble COD from the centrate can increase gas production. This technology has yet to be installed in North America and it has not been demonstrated on the scale of EWPCF. Therefore, this technology failed the fatal-flaw filter.

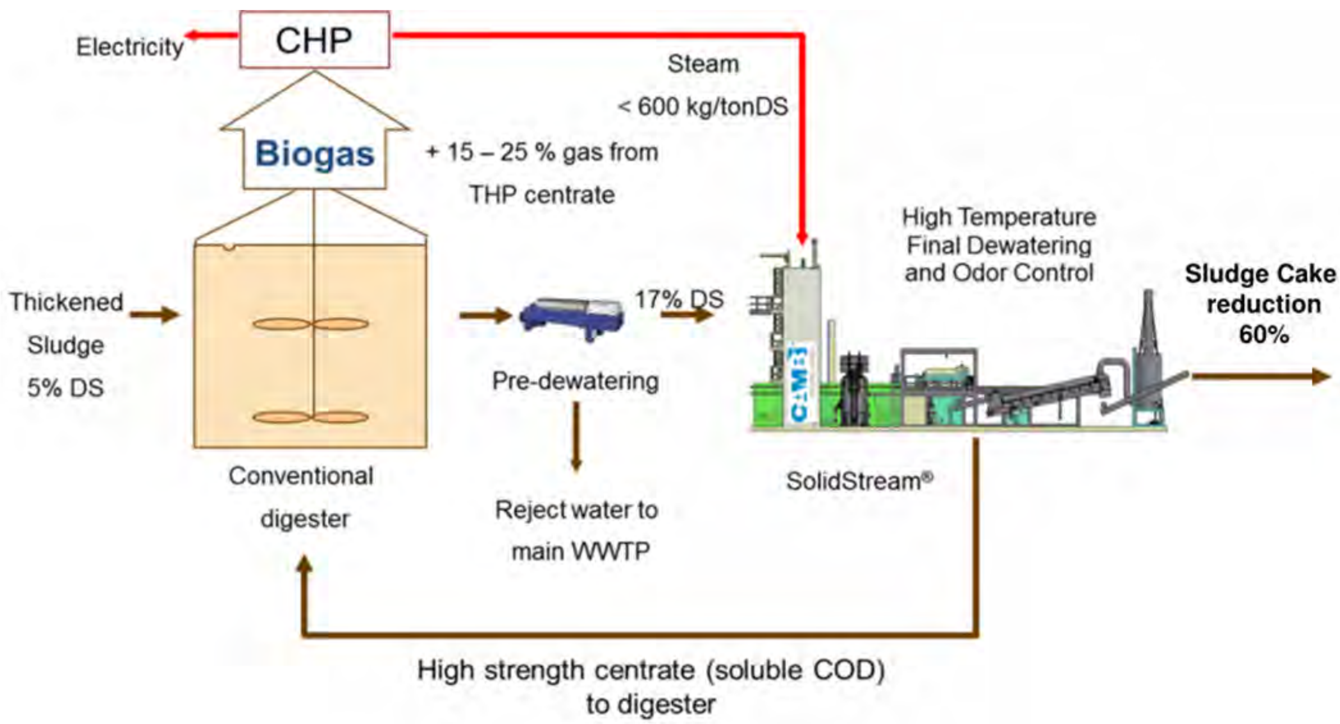

Figure 3-4. SolidStream Cambi process.

Source: http://www.cambi.com/Products/Cambi-SolidStream

3.2.8 Enzymatic Hydrolysis

Enzymatic hydrolysis is a stabilization method that enhances enzyme activity of the anaerobic bacteria by using six serial reactor vessels. The initial enzymatic hydrolysis process tanks operate between 95°F and 108°F with short detention times (e.g., 3 days) to promote acidogenic bacterial growth. The subsequent process tanks can operate at upwards of 95°F, which promotes the growth of methanogens.

The company Monsal (www.monsal.com) is the major technology provider in Europe with about 11 reference installations in the United Kingdom. Monsal claims that its high-rate hydrolysis technology and equipment can be retrofitted to existing digestion plants for upgrade or developed as part of new build turnkey digestion plants. Claimed key benefits of Monsal advanced digestion technology include: (1) high digester loading greater than 0.19 to 0.38 lb-VS/ft^3-d; (2) improved solids dewatering—up to 30 percent DS; and (3) high biogas yields. This technology has not been installed full-scale in North America, and it thus failed the fatal-flaw filter.

3.2.9 Thermo-Chemical Hydrolysis

The thermo-chemical hydrolysis process uses chemicals and elevated temperature to expedite the hydrolysis step. The major technology provider is CNP Technologies and its Pondus TCHP process. CNP currently operates a full-scale pilot operation at the Kenosha WWTP in Kenosha, Wisconsin.

TCHP is designed to focus on TWAS pretreatment. In this process, TWAS is mixed with caustic soda (1,500 to 2,000 parts per million [ppm]) to reach a pH of approximately 11. TWAS is then heated to thermophilic temperatures (150°F to 160°F), using heat exchangers prior to being fed to the reactor. Detention time of the reactor is between 2.0 and 2.5 hours, during which the hydrolysis breaks down the cell walls and releases internal organic acids. The hydrolyzed sludge is then sent to the digesters for digestion. The Pondus TCHP has seen reported benefits of higher VSR, biogas production, and dewaterability of cake. The nature of the chemical storage and the addition of a new reactor in proximity to digestion was believed to be an incompatibility with the EWPCF site, and this technology thus failed the fatal-flaw filter.

3.2.10 Lystek

Lystek is a Canadian company with several full-scale installations in Canada and one full-scale installation in the United States. Lystek uses a process that thermally hydrolyzes the solids after digestion and dewatering. This process can be performed on digested or raw sludge. The result is a Class A fertilizer product. Additionally, Lystek claims that the solid material after it has undergone its process can be fed back into the digester to provide more biogas production and higher VSR. It can also be used as a carbon source for biological nutrient removal. Lystek opened its first U.S. installation in Fairfield, California, in 2016. This is a regional facility treating solids from several Bay area treatment plants, roughly equivalent to the solids production from a 150 mgd treatment plant. There are concerns whether the product meets vector attraction reduction requirements. As a proven process that could be accommodated within EWPCF's footprint, Lystek passed the fatal-flaw filter.

3.2.11 Summary of Fatal-Flaw Evaluation

Table 3-2 displays the results of the fatal-flaw analysis for stabilization technologies. Passing the fatal-flaw filter are MAD, high solids mesophilic digestion, thermophilic digestion, Class A THP, and Lystek as presented and discussed during Workshop 2. All the stabilization technologies selected have a sound technological basis and could theoretically be integrated into the site given sufficient footprint; thus, none of the technologies failed the compatibility criterion. Technologies that failed fatal-flaw criteria did so as follows:

- Technology maturity: Enzymatic hydrolysis, Exelys-DLD, and SolidStream Cambi do not have full-scale installations in North America and thus failed on this criterion.
- Successful operation of comparable size: Enzymatic hydrolysis, Exelys-DLD, and SolidStream Cambi have been proved at demonstration scale only outside of North America.
- Available space: Preliminary calculations were performed to assess the ability to incorporate staged digestion processes such as acid-gas, TPAD, staged MAD, or Exelys-DLD. These calculations are provided for reference in Attachment C. The results indicated that the site cannot accommodate any of the staged digestion processes within the existing digestion area footprint and tankage.

Table 3-2. Solids Stabilization Fatal-Flaw Results

Technology	Technology Maturity	Successful Operation of Comparable Size	Available Space	Compatibility
Mesophilic digestion	Pass	Pass	Pass	Pass
Mesophilic with high solids	Pass	Pass[1]	Pass	Pass
Staged digestion	Pass	Pass	Fail	Pass
Acid/gas phased digestion	Pass	Pass	Fail	Pass
Thermophilic digestion	Pass	Pass	Pass	Pass

Table 3-2. Solids Stabilization Fatal-Flaw Results				
Technology	Technology Maturity	Successful Operation of Comparable Size	Available Space	Compatibility
TPAD	Pass	Pass	Fail	Pass
Class A THP	Pass	Pass	Pass	Pass
Exelys-DLD	Fail	Pass	Fail	Pass
SolidStream Cambi	Fail	Fail	Pass	Pass
Enzymatic hydrolysis	Fail	Fail	Pass	Pass
Chemical hydrolysis	Pass	Pass	Pass	Fail
Lystek	Pass	Pass	Pass	Pass

[1] *Passes fatal flaw filter for inclusion on small digesters at EWPCF only.*

3.3 Dewatering Technologies

This section presents dewatering technologies the BC team looked at as part of this evaluation. EWA has utilized both centrifuges and belt filter presses (BFPs) for dewatering; the team expanded the evaluation to newer technologies as well.

3.3.1 Centrifuge

Centrifuge dewatering is a well-known technology in the wastewater industry. It uses centrifugal force to push solids to the outside of the conveyor for collection and allow water to separate and collect in the center for discharge. Polymer may also be added to increase solids accumulation and separation. The downside of centrifuges is their higher energy demand. Centrifuges are the current dewatering technology employed at EWPCF and passed the fatal-flaw filter.

3.3.2 Belt Filter Press

Another common dewatering technology, BFPs have been in the wastewater industry for decades. BFPs apply mechanical pressure to sludge by pressing two belts together. They use cloth and rollers to remove water from sludge. The machine is basically divided into three zones: (1) gravity, where free-draining water is removed, (2) wedge zone, where sludge is prepared for high-pressure application, and (3) pressure, where high pressure is applied between belts to remove water. Typically, a BFP can achieve solids content of 12 to 35 percent, depending largely on feed characteristics. Maintenance is relative simple; however, odors may be a problem. While BFPs have been used previously at EWPCF, they could not be accommodated in the current dewatering area and would need to be located elsewhere, potentially at the exclusion of other improvements. This aspect of siting will be addressed in the construction of alternatives and will be described in TM 7. BFPs pass the fatal-flaw filter.

3.3.3 Screw Press

Screw presses are a relatively new technology compared to centrifuges and BFP. However, there are many installations in North America. A screw press is a conical screw shaft surrounded by cylindrical sieves. As the screw rotates, the sludge slowly moves along the shaft and water is pressed out through the sieves. Screw press manufacturers claim that this technology offers less maintenance, lower wash water consumption, and lower energy consumption. This proven technology could be integrated into the EWPCF footprint; although, as noted with belt presses, they could not be accommodated in the current dewatering area and would need to be located elsewhere, potentially at the exclusion of other improvements. Screw presses passed the fatal-flaw filter.

3.3.4 Rotary Press

Rotary press is a simple technology. Sludge enters the channel and rotates between two filtering elements. The water passes through these filters as the sludge continues to travel along the channel. The dewatered sludge collects at the exit of the channel where it is extruded as cake. Manufacturers claim that rotary presses have few mechanical parts, reducing maintenance. This proven technology could be integrated into the EWPCF footprint, although, as noted with belt presses, they could not be accommodated in the current dewatering area and would need to be located elsewhere, potentially at the exclusion of other improvements. Rotary presses passed the fatal-flaw filter.

3.3.5 Volute Press

A volute press is similar to a screw press. However, instead of using a shafted screw, it contains main discs stacked together horizontally. As the sludge moves along the discs, water is pressed between the discs. The volute press is found primarily in industrial applications, but there are a few municipal installations in North America. This is, however, a proven technology that could be integrated into the EWPCF footprint; although, as noted with belt presses, they could not be accommodated in the current dewatering area and would need to be located elsewhere, potentially at the exclusion of other improvements. Volute presses passed the fatal-flaw filter.

3.3.6 Bucher Press

The Bucher press has installations worldwide including one installation in Victoriaville, Quebec. This installation dewaters excess sludge and dairy waste and is at a comparable capacity as EWPCF. However, it is not a domestic wastewater treatment facility, thus, the Bucher press failed the fatal flaw filter. The Bucher press operates in cycles, lasting 70 to 120 minutes. The cylinder, which contains filter cloth (filter sleeves), is filled with sludge. A press piston is moved forward, forcing the liquid through the filter cloth. The press piston expands, allowing the sludge to loosen and the process is repeated until the desired solids content has been achieved.

3.3.7 Summary of Fatal-Flaw Evaluation

Table 3-3 displays the results of the fatal-flaw analysis for dewatering technologies. In this category, all but the Bucher press passed the fatal-flaw filter. While there are installations of the Bucher press in Canada and Europe, there are no known municipal sludge installations in North America. Also, the complexity of operation and additional cost was felt to be incompatible with an installation at EWPCF.

Table 3-3. Dewatering Technologies Fatal-Flaw Results

Technology	Technology Maturity	Successful Operation	Available Space	Compatibility
Centrifuge	Pass	Pass	Pass	Pass
BFP	Pass	Pass	Pass	Pass
Screw press	Pass	Pass	Pass	Pass
Rotary press	Pass	Pass	Pass	Pass
Volute press	Pass	Pass	Pass	Pass
Bucher Press	Pass	Fail	Pass	Fail

3.4 Post-Dewatering Technologies

Post-dewatering technologies allow for further processing and the creation of new biosolids products. The existing technology—direct drum drying—is discussed along with other potential process train additions.

3.4.1 Direct Drum Drying

A drum dryer is a direct drying process that mixes heated air with biosolids in a triple-pass rotary system. The heated air comes in contact with the biosolids in the rotating drum, evaporates water from the biosolids, and produces a granule. Drying begins when dewatered sludge is mixed with the recycled solids to control the moisture content of the mixture and minimize sticking to the inner surface of the drum and to allow the wetter sludge to absorb the finer solids coming from the crusher. Air heated to between 850°F and 950°F is introduced in the drum while the sludge mixture tumbles through and exits the other end. From the dryer, the dried solids are fed to a separator to separate the hot air from the solids. The solids are then screened; particles of the appropriate size are conveyed to storage silos while other solids are sent to the crusher. The crushed biosolids are blended with fresh dewatered sludge as described previously. Air emission and odor control systems consist of polycyclones, impingement trays, condensers/sub-coolers, venturi scrubbers, and regenerative thermal oxidizers (RTOs) for the process of off-gas emission control. Up to 75 percent of exhaust gas recirculation is applied to increase the efficiency of the drying system and reduce total dryer system air emissions and odor potential. This existing post-dewatering technology on site at EWPCF passed the fatal-flaw filter.

3.4.2 Indirect Drying

Indirect drying systems use convection heat transfer processes as opposed to conduction heat transfer used in direct dryers. Conduction systems are often called “indirect” dryers because the biosolids do not come in direct contact with the heat medium. A conduction system has significantly less exhaust air to treat than a convection system and typically has a smaller footprint than a similarly sized convection system. But conduction systems such as paddle or vertical tray dryers typically produce an irregular shaped product with a relatively high concentration of fines, although some can produce more uniform granules with reasonably low dust concentrations. Convection systems can operate in the 300°F to 1,000°F range, depending on the specific dryer.

There are a number of manufacturers of indirect dryers. While some indirect drying technologies can produce Class A biosolids, they yield a product with different characteristics from the drum dryer. The complexity of operating two different drying technologies and managing two different products was believed to be an incompatibility with the EWPCF site, and indirect drying thus failed the fatal-flaw filter.

3.4.3 Solar Drying

Solar drying uses radiant and convective heat transfer methods in a greenhouse system to dry the solids. The greenhouse system is typically constructed with multiple large bays that allow for isolating a bay once it is fully loaded. Dewatered solids are spread in thin layers inside a drying chamber. A microprocessor controls vents and fans to optimize the humidity level within the chamber to promote drying. A small automatic mobile mixer agitates the solids on the bed to promote drying. Solar drying is typically used to dry to between 40 and 90 percent TS. Higher TS concentrations require more time in the drying chamber. Demonstrating compliance of solar drying with Class A criteria may require testing of each batch of material. The primary advantage of solar drying is the low energy needed to create a partially dried biosolids product. The primary disadvantage of solar drying is that it requires significant site space; in the case of EWPCF, it requires a greater footprint than that available and it thus failed the fatal-flaw filter.

3.4.4 Gasification

Gasification is a partial oxidation process, where sub-stoichiometric quantities of air (oxygen) are injected with biosolids into a gasifier to allow partial combustion of carbon to CO_2, which then reacts with carbon to produce carbon monoxide (CO). The gasification process takes place at temperatures ranging from 1,472°F to 1,832°F. The gaseous products from biosolids gasification are CO, hydrogen, and CH_4 with trace amounts of nitrogen, CO_2, and H_2S. The product gases (called syngas) can be combusted directly after removal of particulates and acid gases, or further purified to a higher value (greater thermal energy) gas. The process generates a solid residue (char) that can be used for a variety of applications such as for making asphalt or as filler material in building and landscaping.

Gasification of biosolids is considered to be an emerging technology in the United States, with no operating full-scale facilities at this time. It is a complex process that requires drying of the biosolids prior to gasification. There have been numerous pilot studies, and one full-scale system constructed, but that facility was closed for financial reasons during an extended startup phase that encountered numerous difficulties processing the solids. One supplier of gasification systems has recently developed a wood waste gasifier in Tennessee and is processing relatively small quantities of biosolids with the wood waste. As an emerging technology, gasification failed the fatal-flaw filter.

3.4.5 Pyrolysis

Pyrolysis is a thermochemical conversion process that is performed in the absence of oxygen. Like gasification, pyrolysis systems tested to date with biosolids require drying of the solids to 90 percent TS prior to being introduced into the pyrolysis unit. The process converts the biosolids to biochar and syngas. Pyrolysis occurs at temperatures of approximately 1,000°F. The syngas is a low-grade energy source with a heat value of approximately 500 Btu per standard cubic foot and is composed of a mixture of CH_4, CO_2, and hydrogen, with other contaminants. The biochar can be sold as a slow-release fertilizer.

Like gasification, pyrolysis is considered to be in its infancy. One system supplier, KORE Infrastructure, conducted a 6-year pilot test at Los Angeles County Sanitation District that concluded in 2015. KORE is planning for a full-scale system in San Bernardino County with a capacity of reportedly 150 dry tons per day (dtpd). As an emerging technology, pyrolysis failed the fatal-flaw filter.

3.4.6 Incineration

Incineration of dewatered solids achieves the greatest reduction in volume and mass for subsequent reuse or disposal by eliminating the water content of the solids and oxidizing the organic material in the sludge. The resulting sterile ash consists of the inert portion of the dry solids. The overall reduction is greater than 90 percent of wet solids feed. While there are opportunities for beneficial use of the ash, it is typically sent to landfill for disposal.

Incineration is particularly suited for plants with limited space, large solids generation, no anaerobic digestion, and continuous, controlled operation despite weather conditions. The primary concern with incineration is public perception that an incinerator produces harmful air emissions. These perceptions combined with regulatory requirements can result in a need for additional time for planning to obtain an air emissions permit. Complex and advanced air emissions control equipment is required to meet regulation. Because of the public perceptions, stringent regulatory requirements, and heavy onus on the owner to prove environ-mental compliance of this technology, new incineration facilities have not been developed in the United States in decades. In California, only two active incinerators exist at WWTPs, and the incinerator used by the Palo Alto Regional Water Pollution Control Facility will be shut down within the next 5 years. Plans for a new incinerator in Southern California, proposed by Liberty Energy, were sidelined by public opposition and challenges in gaining permit approvals. The likelihood of getting a new incinerator permitted in a timely fashion was believed to be an incompatibility and it thus failed the fatal-flaw filter.

3.4.7 Deep-Well Injection

Deep-well injection for biosolids is a proprietary technology of GeoEnvironment Technologies (GET), which was recently acquired by Advantek Waste Management Services (Advantek), located in Houston. Using this process, undigested sludge would be thickened and then pumped to an injection facility, consisting of a screening system, mixing tank, and high-pressure injection pumps. The high-pressure injection pumps would convey thickened sludge at around 2.5 percent TS content through deep injection wells to an underground suitable geologic formation deeper than 5,000 feet. In the underground formation biosolids would undergo anaerobic digestion, with stabilization of solids and production of CO_2 and CH_4.

The first full-scale demonstration of deep-well injection of biosolids was developed for the City of Los Angeles at the Terminal Island WWTP. The project, referred to as the Terminal Island Renewable Energy (TIRE) project, began operation in 2008 and was scheduled to be a 5-year demonstration project, but has operated for the past 8 years. The process accommodates approximately 13 percent of the City's biosolids production. The success of this technology is geologically specific, and Advantek has been challenged to find other suitable locations, thus causing this technology to fail the fatal-flaw filter.

3.4.8 Dehydration

Dehydration is another term for thermal drying of biosolids. This technology has been used mainly for food waste. Recently, it has been proposed to use with dewatered biosolids. This may be feasible, but experience has shown that it can take years for manufacturers of drying systems used for various materials to learn how to apply the technology for drying biosolids. The difficulties of providing a homogenous source to the dryer and the physical characteristics of the sludge can make thermal drying difficult. As an emerging technology, dehydration failed the fatal-flaw filter.

3.4.9 Fatal-Flaw Evaluation

Table 3-4 contains the results of the fatal-flaw analysis for post-dewatering. The current technology in use, a drum dryer, passed the fatal-flaw filter. The other technologies evaluated failed in all but the available space category, as follows:

- Technology maturity: While biosolids-to-energy technologies have advanced in the past decade, there has yet to be a full-scale installation of pyrolysis or gasification at a municipal WWTP.
- Successful operation: Gasification and pyrolysis pilot and demonstration units have been installed at WWTPs but none of these have been of a size comparable to what would be required for EWPCF.
- Compatibility: While indirect dryers are a well-established technology, EWA already has a direct dryer installed. The difficulty of operating two separate drying technologies and managing two separate dried products presents a fundamental incompatibility with EWA's operations.

Table 3-4. Post-Dewatering Fatal-Flaw Results				
Technology	**Technology Maturity**	**Successful Operation**	**Available Space**	**Compatibility**
Thermal drying: high-quality (drum dryer)	Pass	Pass	Pass	Pass
Thermal drying: low-quality (indirect dryer)	Pass	Pass	Pass	Fail
Partial solar drying	Pass	Pass	Fail	Fail
Gasification	Fail	Fail	Pass	Pass
Pyrolysis	Fail	Fail	Pass	Pass
Incineration	Pass	Pass	Pass	Fail
Deep-well injection	Pass	Pass	Pass	Fail
Dehydration	Fail	Fail	Pass	Pass

Section 4: Ranking of Screened Technologies

This section describes the results of applying the evaluation criteria described in Section 2.3 to further screen and rank the technologies that passed the fatal-flaw filter.

4.1 Evaluation Approach

Following application of the fatal-flaw filter, Table 4-1 summarizes the technologies that were further evaluated using established criteria. The final scores and weightings were fixed in Workshop 2 with EWA staff. Thickening and post-dewatering technologies were not evaluated in this step, as there was no need to further screen these; the technologies listed in Table 4-1 will be carried forward for inclusion in end-to-end alternatives.

Table 4-1. Summary of Screening Technologies

Thickening Technologies	Stabilization Technologies	Dewatering Technologies	Post-Dewatering Technologies
Primary clarifier	Mesophilic digestion	Centrifuge	Drum dryer
Dissolved air flotation	Mesophilic high-solids digestion	Belt filter press	
Rotary drum thickener	Thermophilic digestion	Screw press	
	Class A THP	Rotary Press	
	Lystek	Volute Press	

4.2 Results and Discussion

In this analysis, a weighted average score of 3 or less led a technology to be eliminated from further consideration. The rationale behind the scoring for each technology area is described below and agreed to during Workshop 2.

4.2.1 Thickening

The thickening technologies were not screened further as EWA expressed during Workshop 2 that they wanted all three thickening options listed in Table 4-1 evaluated.

4.2.2 Stabilization

Table 4-2 displays the scoring results for the stabilization technologies that passed the fatal-flaw filter. Among these, thermophilic digestion scored the highest, followed by mesophilic digestion and Class A THP. The rationale behind individual criterion scores is discussed below.

Table 4-2. Stabilization Technology Results

Criterion	Mesophilic Digestion	Mesophilic Digestion with High Solids	Thermophilic Digestion	Class A THP	Lystek
End-use market compatibility	3	3	3	5	2
Proven technology performance	5	2	5	4	2
Minimize life-cycle costs	3	3	4	2	2
Energy/resource recovery	3	4	5	4	3

Table 4-2. Stabilization Technology Results					
Criterion	**Mesophilic Diges-tion**	**Mesophilic Digestion with High Solids**	**Thermophilic Diges-tion**	**Class A THP**	**Lystek**
O&M impacts	4	3	4	3	3
Environmental impacts	4	4	4	4	3
Community and stakeholder impacts	4	4	4	4	2
Project site compatibility	5	3	5	2	4
Total Score	**3.80**	**3.25**	**4.20**	**3.65**	**2.50**

With respect to end-use market compatibility, mesophilic digestion, mesophilic digestion with high solids, and thermophilic digestion all yield a dewatered cake with similar properties. Assuming a Class B cake, this product can be beneficially used in agriculture in Arizona or sent to regional compost facilities for further processing—both end uses are widely employed by other Southern California agencies. Thus, these three technologies received a score of 3 for this criterion. Class A THP produces a low-odor, more granular Class A cake, the aesthetic properties of which make it more acceptable to end users, thus, yielding a higher score. Lystek produces a Class A liquid fertilizer that would be more logistically challenging and expensive to haul the long distances typically required to access sufficient agricultural acreage. In addition, the product is untested in the Southern California region and is questionable in meeting regulatory requirement for vector attraction reduction, resulting in a lower score than the digestion technologies.

For the criterion of proven technology performance, mesophilic digestion and thermophilic digestion are both well proven with long performance records at WWTPs of various sizes. While not as well established as these digestion technologies, Class A THP (primarily Cambi) has nearly 50 worldwide installations, mainly in Europe, with a 20-year performance record. This resulted in a maximum score of 5 for mesophilic and thermophilic digestion and a score of 4 for Class A THP. Lystek has only one U.S. installation of its technology, causing it to receive a score of 2. Additionally, mesophilic digestion with high solids receives a score of 2 because it a less proven technology with only one case study in the U.S. However, there are several full-scale installations using similar non-propriety technology.

Mesophilic digestion and mesophilic digestion with high solids received a score of 3 for minimizing life-cycle costs. Thermophilic digestion allows for greater importation of high-strength waste, a revenue source, and was thus assigned a slightly higher score of 4. Lystek and Class A THP both involve additional processes that have their own personnel and energy demands, resulting in a lower score of 2.

Biogas production, the ability to import high-strength waste, ability to beneficially use biosolids, and net energy demand all influenced the score for the “energy/resource recovery” criterion. Thermophilic digestion offers a greater ability to import high-strength waste. Thermophilic digestion has a higher VSR, which corresponds to a greater gas yield. Conservatively, the energy required to heat a thermophilic digester can be assumed to be equivalent to the gain in VSR, an assumption that will be refined during the alternatives analysis. Improved proportional gas yield and the ability to take in more high strength waste resulted in thermophilic digestion receiving the highest score. Class A THP allows for greater biogas generation but also has somewhat higher energy demands. While Class A THP likely has the highest energy demand of the technologies listed, it also yields a favorable biosolids product, as discussed above. Class A THP received a score of 4. Similarly, mesophilic digestion with high solids received a score of 4 due to increased capacity. Mesophilic digestion once again performs somewhere in the middle, with a score of 3. Lystek uses mesophilic digestion at its core, and while a version of the process can boost biogas production, it also requires importation of chemicals, additional trucks to haul the material to beneficial-use sites, and a slightly larger energy demand than either mesophilic or thermophilic digestion.

With respect to O&M impacts, most of the technologies scored similarly. Mesophilic digestion scored a 4, one point higher than the other technologies, because it reflects a technology that is well established and understood by EWPCF staff.

Most of the technologies are fairly benign from an environmental standpoint and received a score of 4 under the "environmental impacts" criterion. Lystek received a score of 3 because of the need to import chemicals and the generation of additional truck traffic because of the liquid nature of the product. The addition of truck traffic, a sensitive issue in the community around EWPCF, also caused Lystek to be scored lower on the "community and stakeholder impacts" criterion. The other technologies were believed to perform similarly from this standpoint and received a score of 4.

Ability to integrate into the site with respect to both footprint and treatment process compatibility created differentiation among the technologies for the "project site compatibility" criterion. As the established technology at EWPCF, mesophilic digestion received the highest score, a 5. Thermophilic digestion would not significantly change the operation or footprint at EWPCF and thus received the same score. Mesophilic digestion with high solids and Lystek requires additional footprint and a change to the existing operational scheme, causing it to score lower. Class A THP requires operation of a steam plant, additional footprint, and integration of a novel process to the WWTP. As a result, it received the lowest score.

The weighted scores result in thermophilic digestion ranking first, followed by mesophilic digestion, Class A THP, mesophilic digestion with high solids, and Lystek. Based on the final scores, Lystek was eliminated from further consideration. Mesophilic digestion, mesophilic digestion with high solids, thermophilic digestion, and Class A THP will all be included in end-to-end alternatives evaluated under Task 7.

4.2.3 Dewatering

Table 4-3 displays the results of the evaluation for the dewatering technologies. For three of the criteria—life-cycle costs, environmental impacts, and community and stakeholder impacts—the technologies were scored similarly. The more limited performance record of the screw press, rotary press, and volute press caused these technologies to be scored lower from a life-cycle cost standpoint. The open-air nature of a BFP requires additional odor control, which is rated by the lower score for environmental impacts.

Table 4-3. Dewatering Technology Results

Criterion	Centrifuge	BFP	Screw Press	Rotary Press	Volute Press
End-use market compatibility	3	5	4	3	3
Proven technology performance	5	5	3	2	2
Minimize life-cycle costs	4	3	3	3	3
O&M impacts	5	4	3	2	2
Environmental impacts	3	2	3	3	3
Community and stakeholder impacts	4	4	4	4	4
Project site compatibility	5	4	2	3	3
Total Score	**4.35**	**4.10**	**3.05**	**2.65**	**2.65**

Differentiating criteria in this technology category included end-use market compatibility, proven technology performance, O&M impacts, and project site compatibility. With respect to end use, a body of research suggests that dewatering processes employing high-shear processes, such as centrifugation, yield cake with higher odors. Low-shear processes, like BFPs and screw presses, received higher scores than the other technologies. The limited experience with the products from rotary and volute presses also caused these technologies to be scored lower for end-use compatibility.

With respect to proven technology performance, centrifuges and BFPs are the most widely used dewatering technologies in the United States and thus received the highest possible score. Screw presses have been installed at several WWTPs over the past decade, but the performance record of these, including some in California, is mixed, resulting in a lower score. The lowest score, 2, was assigned to rotary and volute presses, whose track record is much more limited. Scoring fell along much the same lines for O&M impacts—both centrifuges and BFPs have been successfully used at EWPCF and operations staff are comfortable operating either one. The other technologies would represent a shift in process.

Centrifuges received the highest score for project site compatibility, as this is the dewatering technology currently employed by EWA. BFPs were used previously for dewatering, but were located in a different process area. As noted earlier, reconfiguration of the plant layout would be necessary to accommodate a change back to this technology. Screw presses require the largest footprint of any of the technologies and, like belt presses, would need to be located elsewhere.

Based on the weighted scores, BFPs scored the highest, followed by centrifuges, screw presses, rotary presses, and volute presses. The latter two scored below a 3 and were thus eliminated from further consideration.

4.2.4 Post-Dewatering

As previously mentioned, all of the post-dewatering technologies failed the fatal flaw filter, except drum drying. Therefore, the drum dryer will be the only option carried forward for further evaluation.

Section 5: Implementation Considerations

The BC team further evaluated the best-ranked technologies by presenting implementation considerations in a workshop with EWA staff held on September 19, 2017. Preliminary feedback on site layouts, process integration, and construction sequencing was considered for incorporation into the future alternatives analysis.

5.1 Thickening and Stabilization

The PMP established a location for the RDT units, shown in Figure 5-1. Thickening improvements can help make the digestion process more efficient and will create more hydraulic capacity by removing water from the sludge. With respect to the stabilization processes, several figures were developed to demonstrate potential siting considerations and construction sequencing. These are presented as Figures 5-1 through 5-3 and are discussed further below.

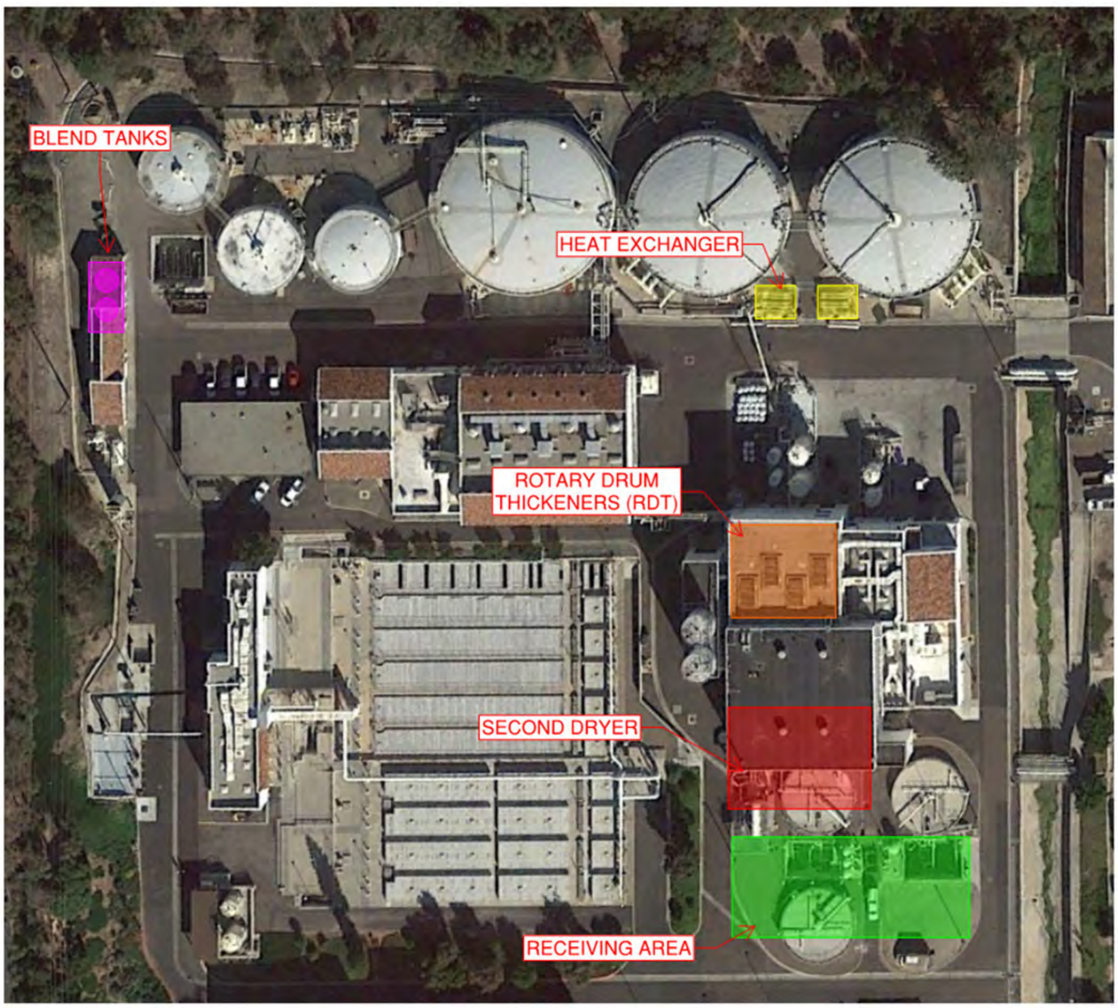

Figure 5-1. Preliminary layout for thermophilic digestion with a second dryer and expanded facilities for high strength waste receiving.

Brown AND Caldwell

Mesophilic digestion is the current stabilization process. Preliminary calculations indicate that the existing tankage is insufficient to accommodate future flows and loads, particularly if there is a desire to import greater quantities of high-strength waste. If mesophilic digestion were to be maintained, the smaller, 300,000-gallon digesters (digesters 1, 2, and 3) would need to be rehabilitated and brought on line.

Thermophilic digestion occupies essentially the same footprint as mesophilic digestion. More heat exchanger capacity would need to be brought on line; this could be accomplished by replacing the existing units with taller, higher-capacity units. For the alternatives analysis, two thermophilic scenarios will be explored. The first is a 15-day HRT scenario, which guarantees Class B quality, but is limited by the ability to receive high-strength waste based on hydraulic capacity. A second scenario is a 10-day thermophilic process. Digestion remains stable at a 10-day HRT and EBMUD and others have successfully operated this process for years. This scenario allows EWA to receive greater quantities of high-strength waste, and a new receiving station could be constructed where some of the smaller digesters are currently located (Figure 5-1). Co-digestion capacity in these scenarios will be analyzed and described further in TM 4.

Implementation of THP (Figures 5-2 and 5-3) is somewhat more complicated, as creating space for the THP units requires demolition of existing process units. Figure 5-2 shows a layout in which the smaller digesters are demolished in favor of the THP units and the high strength waste receiving area shown in Figure 5-1 has been moved in closer proximity to the dryer building. A second layout developed requires demolition of the existing DAFTs to accommodate the THP units. In this scenario, shown in Figure 5-3, thickening upgrades would need to be performed prior to installation of the THP units.

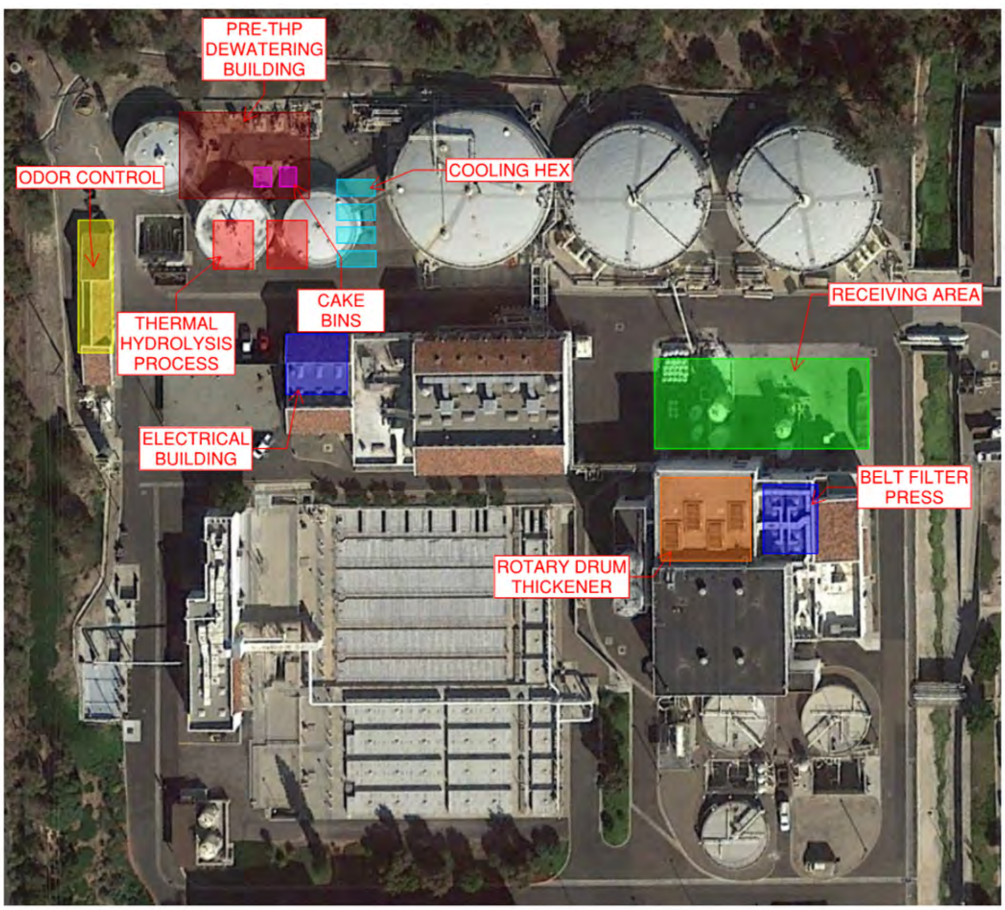

Figure 5-2. Preliminary layout for THP where the smaller digesters are demolished for the THP units.

Figure 5-3. Preliminary layout for THP where the DAFs are demolished for the THP units.

5.2 Thermal Drying

One of the major questions to be addressed by the BEE is whether a second thermal dryer is necessary to meet EWA's goals. The existing building is space-constrained and a building modification may need to be constructed to accommodate a second dryer. Discussions on such modifications are currently underway and appropriate costs will be incorporated into the alternatives evaluation. In the event a new building is deemed necessary, the BC team prepared preliminary layouts for the second dryer that require demolition of the existing DAFTs. Under this scenario, thickening changes may need to be performed prior to the installation of the second dryer.

Section 6: Conclusions and Next Steps

Screening of biosolids technologies resulted in a final selection of technologies to be included in end-to-end alternatives. The technology combinations are represented in Figure 6-1 and will be combined with the results of Tasks 3, 4, and 5 for the creation of end-to-end alternatives for analysis in the SWEET model. The three stabilization alternatives—mesophilic digestion, thermophilic digestion, and Class A THP—will each be evaluated both with and without the second drying train necessary to accommodate future growth. Development of end-to-end alternatives will be performed in cooperation with EWA staff prior to analysis.

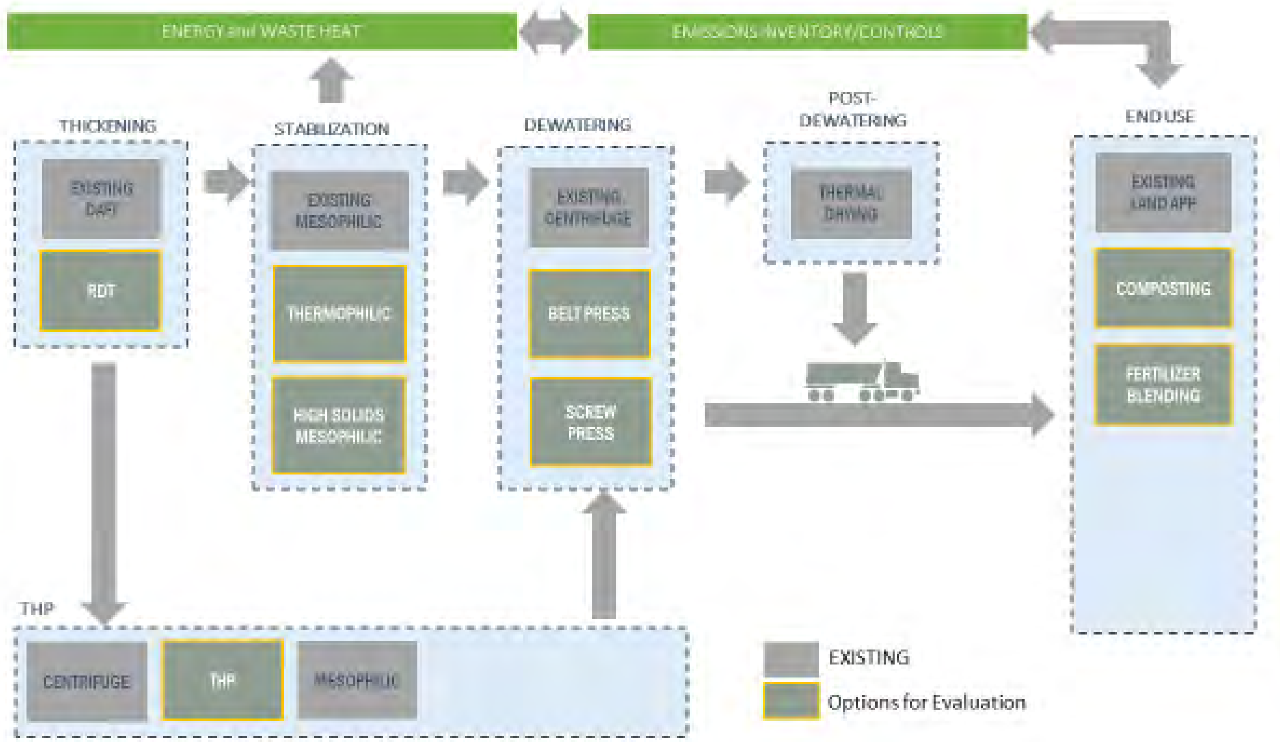

Figure 6-1. Biosolids treatment technology options for EWCPF end-to-end project alternatives.

Attachment A: Workshop Meeting Minutes

Meeting Minutes

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Prepared for: Encina Wastewater Authority
Project Title: Energy & Emissions Strategic Plan & Biosolids Management Plan Update
Project No.: 150871

Purpose of Meeting: Workshop #2 **Date:** August 16, 2017
Meeting Location: Encina Wastewater Authority **Time:** 1:30 – 5:00 PM
Minutes Prepared by: Hari Seshan and Jocelyn Lu, Brown and Caldwell

Attendees:

Doug Campbell, Encina, JPA	Adam Ross, Brown and Caldwell
Scott McClelland, Encina JPA	Hari Seshan, Brown and Caldwell
Jimmy Kearns, Encina JPA	Jocelyn Lu, Brown and Caldwell
Mike Steinlicht, Encina JPA	Natalie Sierra, Brown and Caldwell
Octavio Navarrete, Encina JPA	Scott Lacy, Brown and Caldwell
Nathan Chase, RMC	Tom Chapman, Brown and Caldwell

Attachments:

- Workshop #2 Presentation Slides

Decisions

The following is a list of decisions made as a result of the meeting discussion:

- BC team to evaluate RDTs against the current status quo of primary clarifier and DAFT.
- Stabilization technologies that moved to the next round of evaluation: Mesophilic Digestion, Mesophilic Digestion with High Solids, Thermophilic Digestion, and Traditional CAMBI.
- Dewatering technologies that moved to the next round of evaluation: Centrifuges and Belt Presses.
- Post-dewatering technology that moved to the next round of evaluation: Thermal Drying - High Quality (Drum Dryer).
- Alternative power production technologies that moved to the next round of evaluation: Internal Combustion Engines (Status Quo), Internal Combustion Engines – with Gas Conditioning, Internal Combustion Engines – with Exhaust Treatment, Digester Upgrading – Pipeline Injection, Micro-Turbines, Biosolids Drying – Direct Use of Biogas, Large Scale Photovoltaics (PV), Small Scale Rooftop PV.
- Waste heat technologies that moved to the next round of evaluation: Small-Scale Steam Turbines, and Thermo/THP.

Action Required

The following is a list of actions required as a result of the meeting discussion:

- Jimmy to send Adam maintenance schedule costs.
- Octavio to send WAS daily flow data to Hari Seshan (Hari).
- Scott L to send list of additional data/document requests over to Scott M after updating based on discussion.
- Scott M to send a list of EWA attendees for the Waste Haulers Meeting to BC.
- Adam to send a draft agenda of the Waste Haulers meeting to EWA and finalize per any EWA comments.
- Octavio to send EWA's SDG&E point of contact to Adam. EWA and BC to discuss initial contact with SDG&E regarding biomethane pipeline injection.
- Octavio to send Hari lab data on the performance of the centrifuges.
- Tom to work with Octavio on refining the solids mass balance.
- Adam to present a big picture view of the power production alternatives at the next workshop.
- BC to identify technologies that would be beneficial to visit at WEFTEC.
- BC will set up a meeting with Anaergia to discuss project goals and opportunities. This meeting will be separate from the Waste Hauler meeting.
- Scott L and Scott M will schedule Workshop 3 for mid-September – aim for conducting the Waste Hauler meeting on the same day.
- EWA will take the dryer out of service in September/October. BC requests that any condition assessment results be shared with the team – particularly related to the increased use of digester gas (siloxane or hydrogen sulfide issues).
- BC to check in with EWA to confirm is any support is needed related to the next board meeting on Oct 11.

Summary

Workshop #2 was held for the Encina Water Authority (EWA) Energy & Emissions Strategic Plan & Biosolids Management Plan Update. The purpose of this Workshop was to review pending administrative tasks and provide task updates. A summary of the discussion is provided below:

Introductory Items

BC started off the meeting by reviewing the schedule and goals for the meeting. The goals are to generate content and direction for the project team moving forward.

- This month, the Brown and Caldwell (BC) team will be:
  - Preparing a baseline report, to be reviewed by EWA in September.
  - BC will also be preparing report sections of Tasks 2 and 3 by September.
  - In October and November, BC will be developing SWEET alternatives and providing more clarity on how the pieces interact.
- Adam Ross (Adam) stated that he expects to have more questions about permitting, cogeneration (cogen), electrical rates, and where to send digester gas, and would appreciate dialogue between now and the next workshop. EWA staff recommended for him to work with Octavio Navarrete (Octavio).

<u>New Data Request Items</u>

BC reviewed new data request items with EWA. They included:

- Trussell food waste capacity report - Scott McClelland (Scott M) stated that he has the data, but not the report, on the Trussell study. Preliminary conclusions of the report indicate that EWA could accept an additional 80,000 gal/week of FOG and 25,000 gal/week of brewery waste. EWA expect it'll take about another month before the report is ready. Imported wastes are received Monday – Friday/Saturday. A constant feed to the digesters is provided until around Saturday afternoon. A potential limitation to high strength waste acceptance is truck offloading capacity. A food waste pilot program began on Monday, 9/14.
- O&M costs for cogen engines - Adam asks if EWA has annual O&M costs for the engines. Jimmy Kearns (Jimmy) states that EWA has annual costs for the maintenance schedule.
    - **ACTION: Jimmy to send Adam maintenance schedule costs.**
- WAS flow data
    - BC requests the WAS flow data, and Octavio indicates that EWA does have that data.
    - **ACTION: Octavio to send WAS daily flow data to Hari Seshan (Hari).**
- Air permitting summaries or progress
    - Doug Campbell (Doug) sent Adam the latest email from Don King (Don).

<u>Outstanding Data Requests</u>

BC reviewed outstanding data requests with EWA. They included:

- Cogen drawing and cut-sheets
    - Natalie Sierra (Natalie) points out that BC has received drawings from Andritz.
- Information on energy management
- High strength waste storage (typical day operating procedure)
- **ACTION: Scott L to send list of additional data/document requests over to Scott M after updating based on discussion.**

There was a subsequent discussion on wasted gas that was being flared. Octavio explains that the operators need to manually control the digester gas flow to the dryer, which results in some flaring. Operators generally try to set the digester gas flow rate to avoid drawing down the gas system and triggering natural gas blending at cogen. This typically results in a conservative offtake of digester gas to the dryer which results in some flaring. Mike Steinlicht (Mike) asks how much is being flared, and Adam calculated that about 180 kW of gas was being flared (averaged over a month) in current operation.

Cogeneration operation was discussed. EWA operates two engines on digester gas 24/7. A third engine operates on natural gas during peak power rates. EWA physically disconnects from the power grid to avoid demand and consumption charges.

FOG is fed to the digesters at a constant rate of 12 gallons per minute. FOG is fed to only one or two digesters, not all. The FOG feeding begins on Monday with first deliveries of the week, and continues into Saturday to pump down material from the last deliveries on Friday.

Meeting with Waste Haulers

BC reviewed the timing, attendees, and goals of the Waste Haulers Meeting. Below is a summary of the discussion:

- Scott L reviewed the potential list of attendees, which included: EWA representatives, BC representatives, Waste Management (WM), Republic, EDCO, and potentially LES or Anaergia.
    - **ACTION: Scott M to send a list of EWA attendees for the Waste Haulers Meeting to BC.**
- Scott M stated that the intent of the meeting is to develop a public-private partnership and noted increase grant eligibility by having this kind of relationship.
- Mike emphasized that the elected officials want all of the waste haulers at the table, especially those that operate within EWA's service area.
- Adam reviewed the draft Waste Hauler Agenda, which would cover background on the plant, current operation, and a discussion of potential capacity.
- Scott M stated that he would like to have an agenda finalized and sent out to each waste hauler 30 days in advance of the meeting, to give them adequate prep time.
    - **ACTION: Adam to send a draft agenda of the Waste Haulers meeting to EWA and finalize per any EWA comments 30-days in advance of the meeting.**
- Adam stated that another discussion point for the meeting is the waste haulers potential interest in accepting compressed natural gas (CNG). Scott M stated that SDG&E should be involved in these conversations as well. A meeting should be arranged with SDG&E.
    - **ACTION: Octavio to send EWA's SDG&E point of contact to Adam.**
- Different gas delivery options, tube trailer vs. pipeline, were discussed. Adam stated that a tube trailer has less stringent standards than a pipeline, but there would be tube trucks coming in and out of the facility. However, the pipeline would have more stringent sampling/reporting requirements and the investment for an interconnection for the pipeline could cost $1 – 2 million dollars. This will be developed as the alternatives analysis is advanced.

Other Outstanding Items

BC reviewed their understanding of the discussion with Anaergia:

- Adam stated that Anaergia is promoting Omnivore as a process treatment option, which may or may not be the right fit at EWA. However, there might be opportunity for Anaergia to work with waste haulers for pre-processing food waste.

Review of Mass Balance and Project Flows and Loads

BC presented the project flows and loads:

- Mass Balance
    - Hari reviewed the assumptions made to calculated WAS. Octavio responded that the actual WAS flow is around 0.75 MGD, and that he could send that data to BC (ACTION above).
    - Adam stated that the VSR value of 65% seemed suspiciously high. Octavio stated that EWA's VSR value was closer to 55%.
    - Hari stated that the centrifuge % capture right now is 78%. Octavio responded that the capture rate for the centrifuges is consistently 95%, and that the calculated value is probably lower because of values during start-up and shut-down.
        - **ACTION: Octavio to send Hari lab data on the performance of the centrifuges.**

  - Tom requested that the BC team review the data with Octavio after he send is to BC.
    - **ACTION: Tom to send up conference call with Octavio after reviewing the data.**
- Solids Mass Balance Comparison
  - Tom presented a graph that shows that BC's calculated solids loading was higher than the calculated values in the Process Master Plan (2016).
  - Octavio stated that one reason for the increase might be a 2015 change in how EWA sampled the influent flow.
  - **ACTION: Tom to work with Octavio on refining the solids mass balance.**
- Power Loads and Gas Usage
  - Adam reviewed the gas usage graphs with EWA.
  - Digester Gas Usage Summary – Total gas production is trending up, probably due to the increase in high strength waste deliveries. Adam pointed out that the yellow "Total Gas Production" line didn't match up with the top of the bars, which is normal. Scott M pointed out that the important part is that the yellow line followed the same trend as the bars.
  - Natural Gas Usage Summary - Most of the natural gas is being used for the heat dryer and cogen, which is expected.
  - Power Production and Import – Currently, EWA is making about 80% of their electricity needs. This means that EWA could potentially export power. A look into the SDG&E power bills also showed that the actual kWh power that EWA is purchasing only constitutes $10,000 out of a $70,000 bill. The majority of the bill is non-coincident and standby power.
    - Mike stated that he had talked to SDG&E about the standby charges and haven't been able to get around them.
- Engine Fuel Use
  - Octavio explained that the increase in natural gas in November 2015 was because they needed to switch to natural gas to stay below emission limits.

<u>Screening of Technologies</u>

BC the fatal flaw filter and evaluation criteria, and then evaluated each process technology against that criteria. The results of the evaluation are summarized below and more details are included in the attached Workshop #2 PowerPoint slides.

- There were four fatal flaw filters:
  - At least one successful North American installation of the technology
  - At least one successful installation in a facility of similar size
  - There is available space to implement that technology
  - Compatibility with plant size and any existing equipment
- The technologies that passed the fatal flaw filter were then scored for each evaluation criteria, which included: end use market compatibility, proven technology performance, life cycle costs, energy/resource recovery, O&M impacts, environmental impacts, community and stakeholder impacts, and project site combability.
  - Each evaluation criteria was then weighted to reflect EWA's priorities.

  - Technologies that scored lower than a 3 were eliminated, and technologies that scored greater than a 3 would be evaluated through the SWEET model.
  - O&M impacts criteria will be clarified to describe reduction in O&M staff time.
- Thickening Technologies
  - Prior planning efforts recommended evaluating rotary drum thickeners (RDTs) against the existing primary clarifier and dissolved air flotation thickeners (DAFTs). EWA concurred with that recommendation.
  - Natalie asked if the team should add Anaergia's Omnivore to the list of technologies to evaluate. Scott L proposed that that decision to be made after a meeting with Anaergia takes place.
    - **DECISION: BC team to evaluate RDTs against the current status quo of primary clarifier and DAFT.**
- Stabilization Technologies
  - Technologies that failed the fatal filter: Staged Digestion, Acid/Gas Phased Digestion, Temperature Phased Anaerobic Digesion, Enzymatic Hydrolysis, Chemical Hydrolysis, THP – DLD, and Solid Stream CAMBI.
  - Technologies that scored lower than a 3 in the evaluation criteria: Lystek.
  - **(DECISION) Stabilization technologies that moved to the next round of evaluation: Mesophilic Digestion, Mesophilic Digestion with High Solids, Thermophilic Digestion, and Traditional CAMBI.**
- Dewatering Technologies
  - Technologies that failed the fatal filter: Bucher Press.
  - Technologies that scored lower than a 3 in the evaluation criteria: Screw Press, Rotary Press, and Volute Press.
  - **(DECISION) Dewatering technologies that moved to the next round of evaluation: Centrifuges and Belt Press.**
- Post-Dewatering Technologies
  - Technologies that failed the fatal filter: Thermal Drying: Low Quality (Indirect Dryer), Gasification, and Pyrolysis.
  - Technologies that scored lower than a 3 in the evaluation criteria: N/A
  - **(DECISION) Post-dewatering technologies that moved to the next round of evaluation: Thermal Drying: High Quality (Drum Dryer).**
- Alternative Power Production Technologies
  - Technologies that failed the fatal filter: Fuel Cells and Wind Turbines.
  - Technologies that scored lower than a 3 in the evaluation criteria: Energy Storage (Batteries), Large Scale Solar Photovoltaics
  - **(DECISION) Alternative power production technologies that moved to the next round of evaluation: Internal Combustion Engines (Status Quo), Internal Combustion Engines – with Gas Conditioning, Internal Combustion Engines – with Exhaust Treatment, Digester Upgrading – Pipeline Injection, Micro-Turbines, Biosolids Drying – Direct Use of Biogas, Large-Scale Solar Photovoltaics (PV), and Small Scale Rooftop PV.**
- Waste Heat Technologies
  - Technologies that failed the fatal filter: Absorption and Adsorption Chillers, Organic Rankine Cycle, and Gasification of Biosolids.

- Technologies that scored lower than a 3 in the evaluation criteria: N/A
- **(DECISION) Waste heat technologies that moved to the next round of evaluation: Small-Scale Steam Turbines, and Thermo/THP.**

<u>Creation of End to End Alternatives</u>

The BC team reviewed initial alternatives that were to be evaluated, as well as different power production alternatives. The power production alternatives included:

- Baseline: existing cogen and drying
- Baseline with gas conditioning
- Existing cogen with vehicle fuel (via pipeline injection or tube trailer)
- Existing cogen with microtubines
- Existing cogen with steam boiler/turbine
- New cogen permit, CO catalyst and selective catalytic reduction (SCR), with gas conditioning
- Vehicle fuel (primary use of digestive gas) with existing cogen
- **ACTION: Adam to present a big picture view of the power production alternatives at the next workshop.**

<u>Grant Updates</u>

BC provided an overview of different grant programs, and explained how the program would fit into the SWEET model. The programs included:

- Self-Generation Incentives Program
- Low Carbon Fuel Standard
- Renewable Fuel Standard
- Organics Grant Program
- Healthy Soils Program
- Green Project Reserve

<u>Air Permitting Discussion</u>

BC and EWA discussed the current efforts of the air permit modification. EWA is submitting a request for permit modification in one week. If successful, it would increase the permitted cogen capacity by ~20%.

<u>Look Ahead & Wrap-Up</u>

The meeting ended with a look ahead and reviewing pending action items.

- Workshop #3 will take place in mid-September, and the team will try to schedule the Waste Hauler Meeting on the same day.
- The team will present the following in Workshop #3:
  - Baseline SWEET model
  - Conceptual layouts and details of alternatives for consensus and feedback
  - Air permitting impacts on power production alternatives
  - Grant updates
- WEFTEC is also taking place in early-October. Mike stated that it would be beneficial to walk the floor together with BC to look at potential technologies.
  - **ACTION: BC to identify technologies that would be beneficial to visit at WEFTEC.**

- ACTION: BC to check in with EWA to confirm is any support is needed related to the next board meeting on Oct 11.

Brown AND Caldwell

Energy & Emissions Strategic Plan & Biosolids Management Plan Update

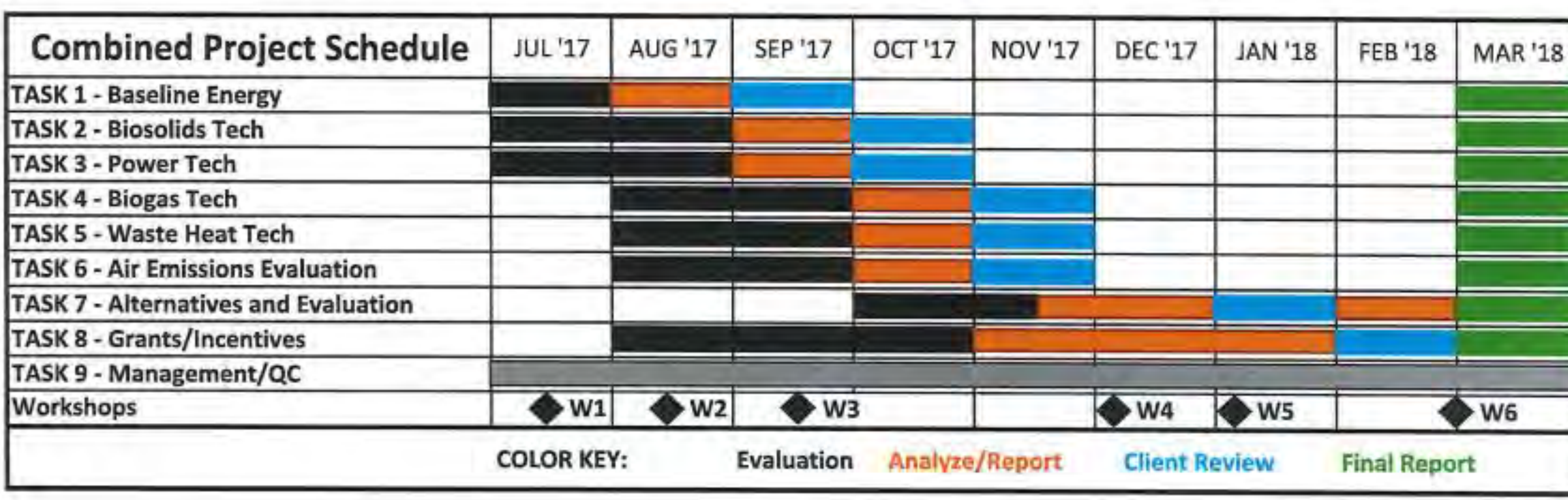
ENCINA WASTEWATER AUTHORITY

Workshop #2 – August 16, 2017

Encina Water Pollution Control Facility

Project Schedule

- Progress On Schedule
- Task 1 Energy Baseline Complete
- Other Tasks (except 7) are Under Way
- Workshop #2 Today



Agenda

- Administrative (20 min)
  - Status of data requests
  - Comments on waste hauler agenda
  - Discussion with Anaergia
- Review Mass Balance and Projected Flows and Loads (45 min)
- Review Fatal Flaw and Screening Criteria (30 min)
- Screen Technologies (1 hr)
- Discussion of Preliminary End to End Alternatives (30 minutes)
- Grants Update (10 min)
- Air Emissions Review (5 min)
- Wrap-Up/Review Action Items (10 min)

New Data Requests

- Trussell food waste capacity report
- O+M costs for the engines (have costs for electricity for the system, but not for gas treatment, upkeep, general maintenance, etc.)
- WAS daily flow data (back-calculated for mass balance)
- FOG TS and VS data (used assumptions from 2016 PMP for mass balance)
- Any air permitting summaries or progress between EWA and Don King

Outstanding Data Requests

- Cogen and solids systems drawings, engine cut sheets
- Dryer system drawings and cut sheets
- Recent air permitting efforts – progress, memos, contact info
- Copies of current air permits (SDAPCD and Title V)
- Energy Management – typical day operating procedure:
  - Cogen strategy
  - Peak period disconnect from utility
  - HSW storage and feed strategy

Waste Hauler Agenda

- Timing: September (coordinate with Workshop 3)
- Attendees:
  - EWA – Scott, Jimmy
  - BC – Adam, Ari
  - WM
  - Republic
  - EDCO
  - LES?
  - Anaergia?
- Goals:
  - Provide background info to haulers about EWA's goals and BEE effort
  - Determine availability of pre-processed food waste, market demand for an EWA initiative to receive more material, tipping fee range for SWEET analysis
  - Gauge interest in a renewable CNG partnership
  - Discuss "next steps" such as letter of intent, future coordination

Other Outstanding Items

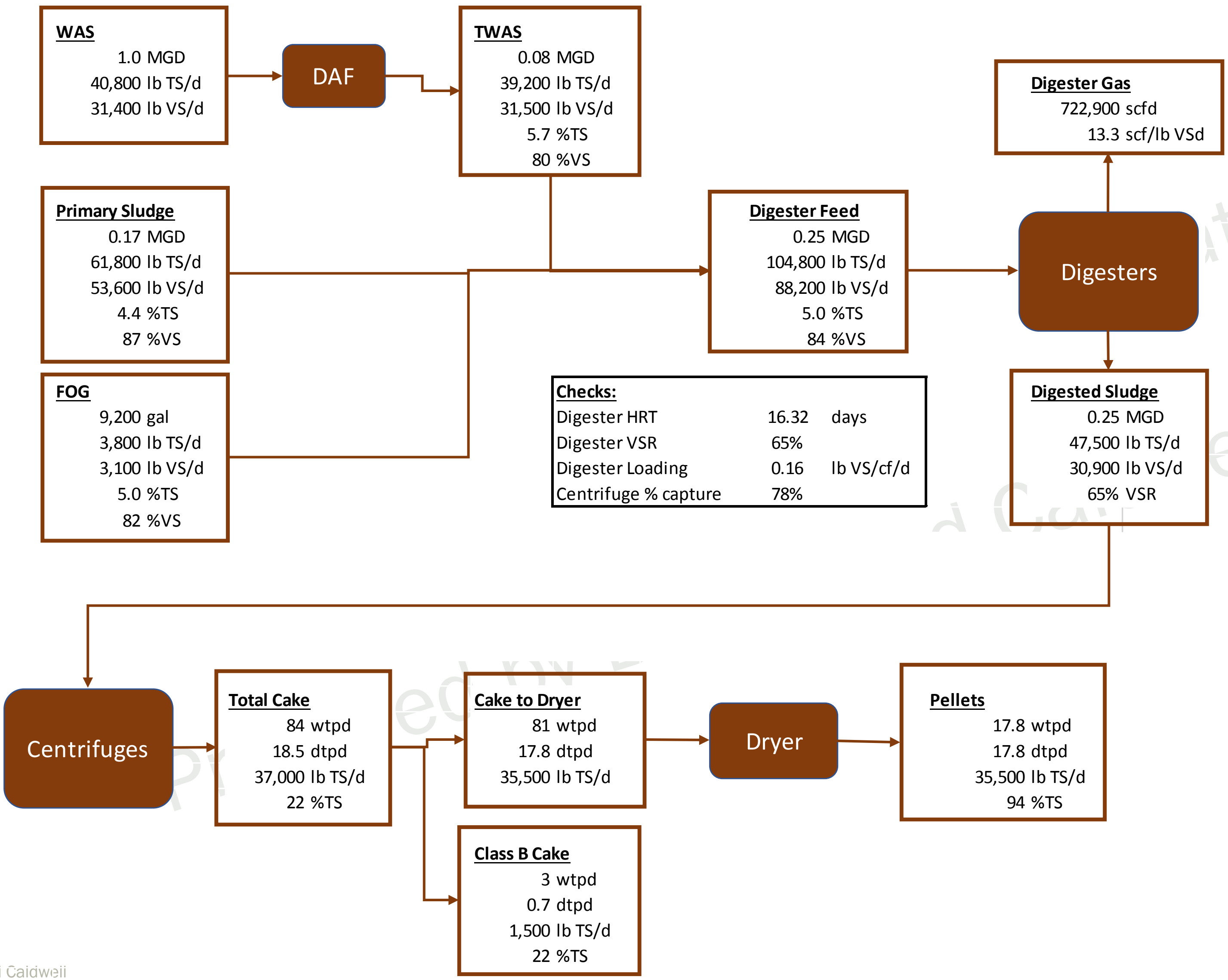
- Discussion with Anaergia
  - Omnivore as an alternative
  - Orex or Biorex for food waste pre-processing
  - Status of food waste receiving project(s) with Republic
  - Capacity at Rialto facility for dried product?

Review of Mass Balance and Projected Flows and Loads

Brown AND Caldwell

Mass Balance

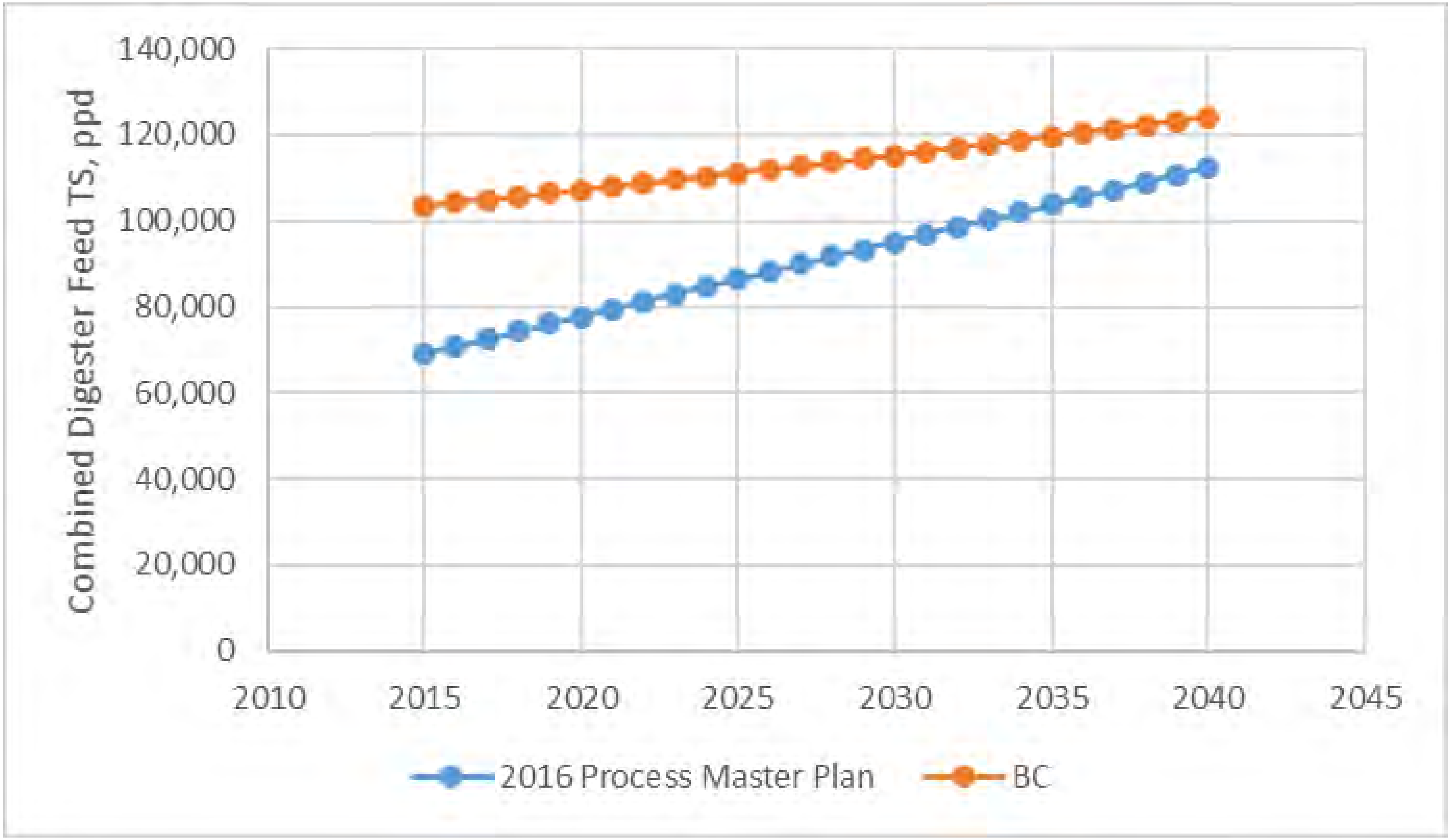
MAY 2015 - JUNE 2017



Mass Balance Assumptions

- TWAS flows that were zero and subsequent loads when TWAS flow was zero were excluded. Assumed percent capture rate for the DAFTs is 95%.
- TWAS flows were taken from DAFT totalizer data and digester feed meters.
- The digester feed flow from July 1, 2016 to June 2017 were subtracted daily to obtain a daily digester feed volume. This was based on the assumption that the flow values were cumulative from a meter reading starting 7/1/16.
- The Class B cake data were averaged with zero data to obtain an annualized daily average.
- FOG data were a daily average of the volumes received. This assumes FOG is fed 24/7/365. Assumes %TS and %VS are 5% and 82%, respectively.
- To calibrate the mass balance as shown, 2,300 lbs TS/d and 1,900 lbs VS/d were added to Primary Sludge.

Solids Mass Balance Comparison



Sludge Production Peaking Factors

	Max Month	Peak 2-Week	Peak Week	Peak Day
Primary Sludge	1.23	1.3	1.4	1.60
WAS	1.23	1.3	1.4	1.60
Combined Sludge	1.23	1.3	1.4	1.60

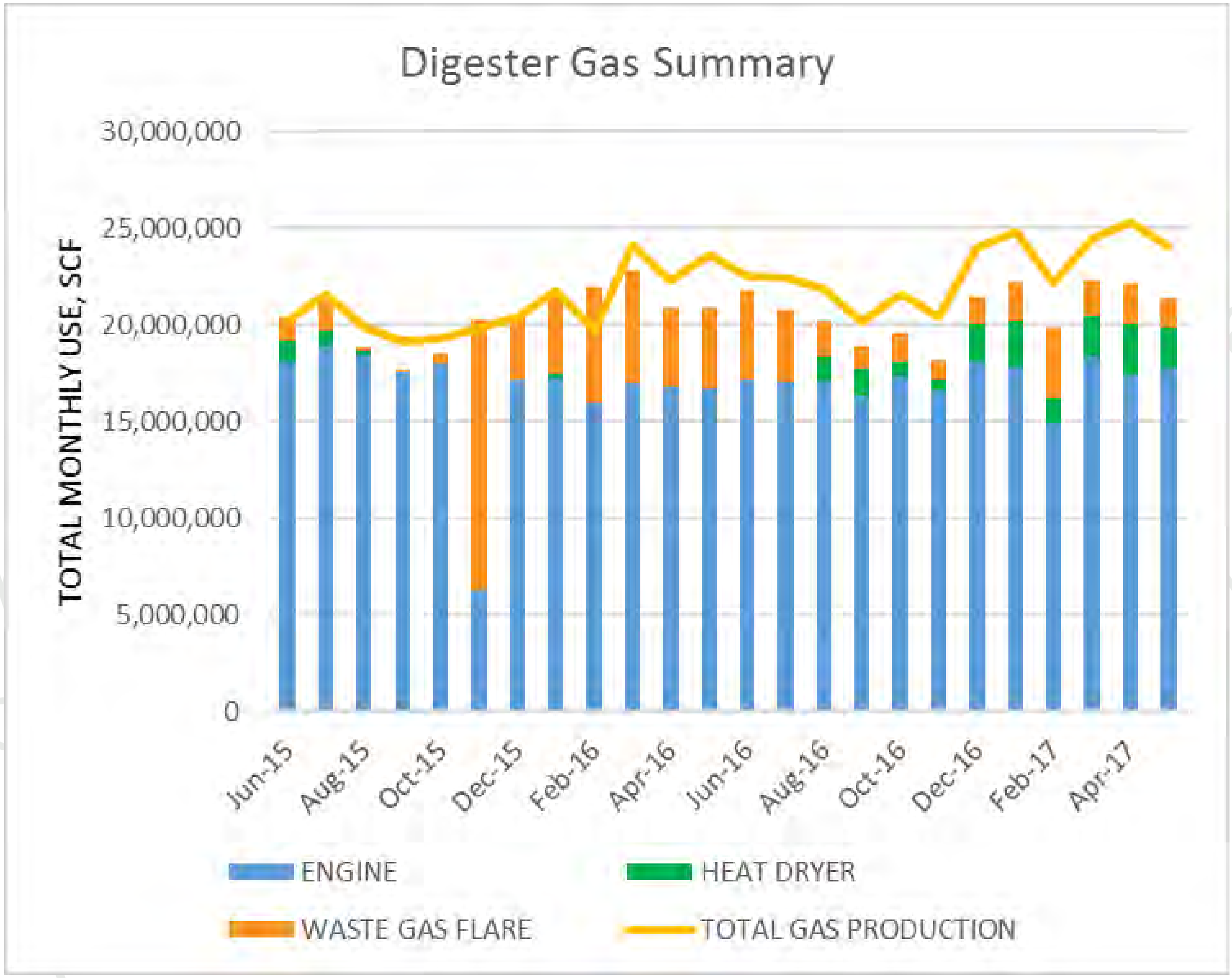
Notes:

- Peaking factors for maximum month and peak day conditions are developed based on 2016 PMP solids projections.
- Peaking factors for maximum 2-week and maximum week conditions are proposed based on historical data.

Power Loads and Gas Usage

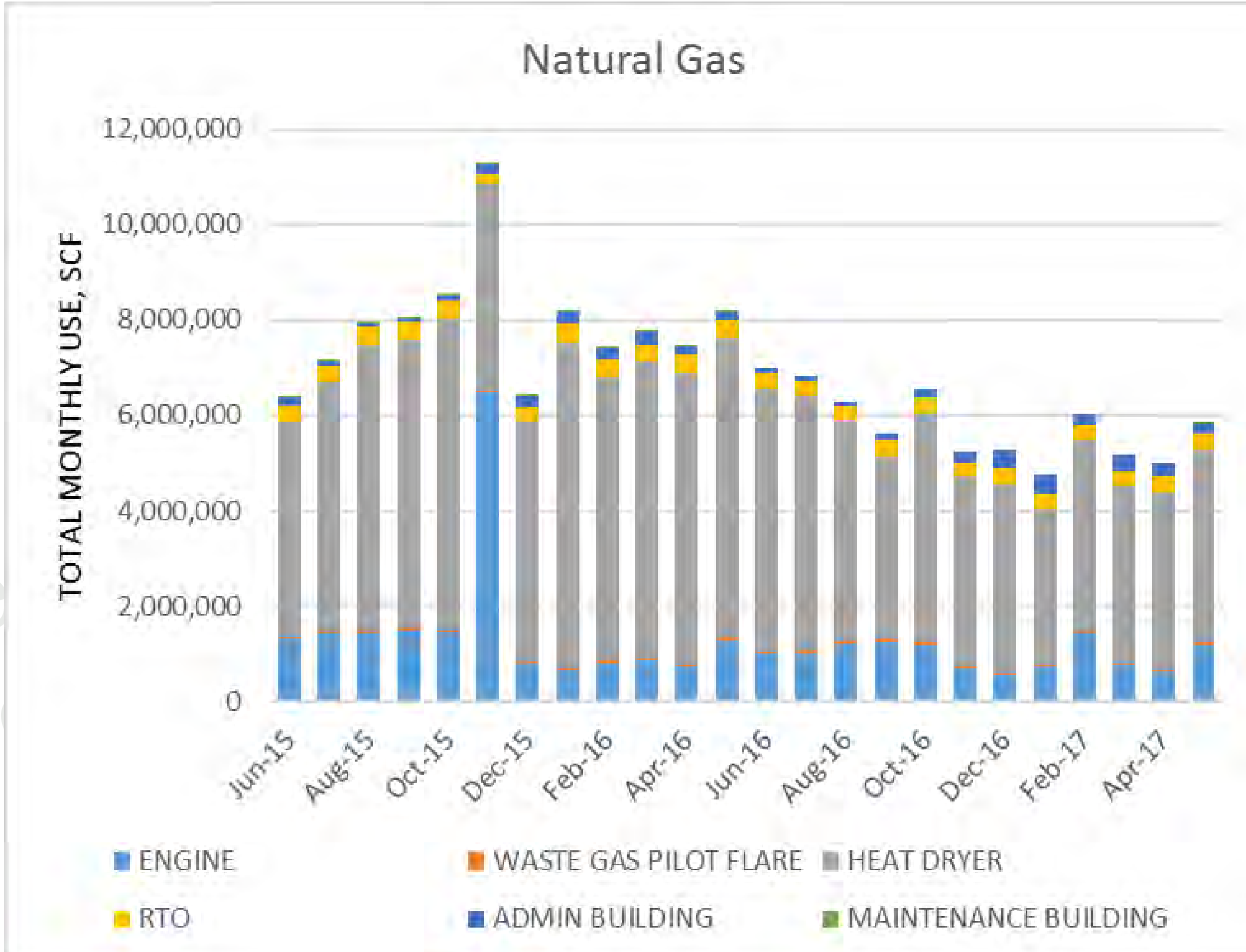
- Power:
  - Monthly production: 1,500 kW (2, 750 kW engines full output – 80% of total electrical demand)
  - Monthly import: 385 kW equivalent (1,390 MWh per year)
- Digester gas:
  - Average production: 1,645,000 therms per year
  - Engines: 1,263,000 therms per year
  - Waste gas: 229,000 therms per year
  - Heat dryer: 57,000 therms per year
- Natural gas: 856,000 therms per year
  - Engines: 156,000 therms/year
  - Other plant use: 700,000 therms/year

Digester Gas Usage Summary – Last 2 years



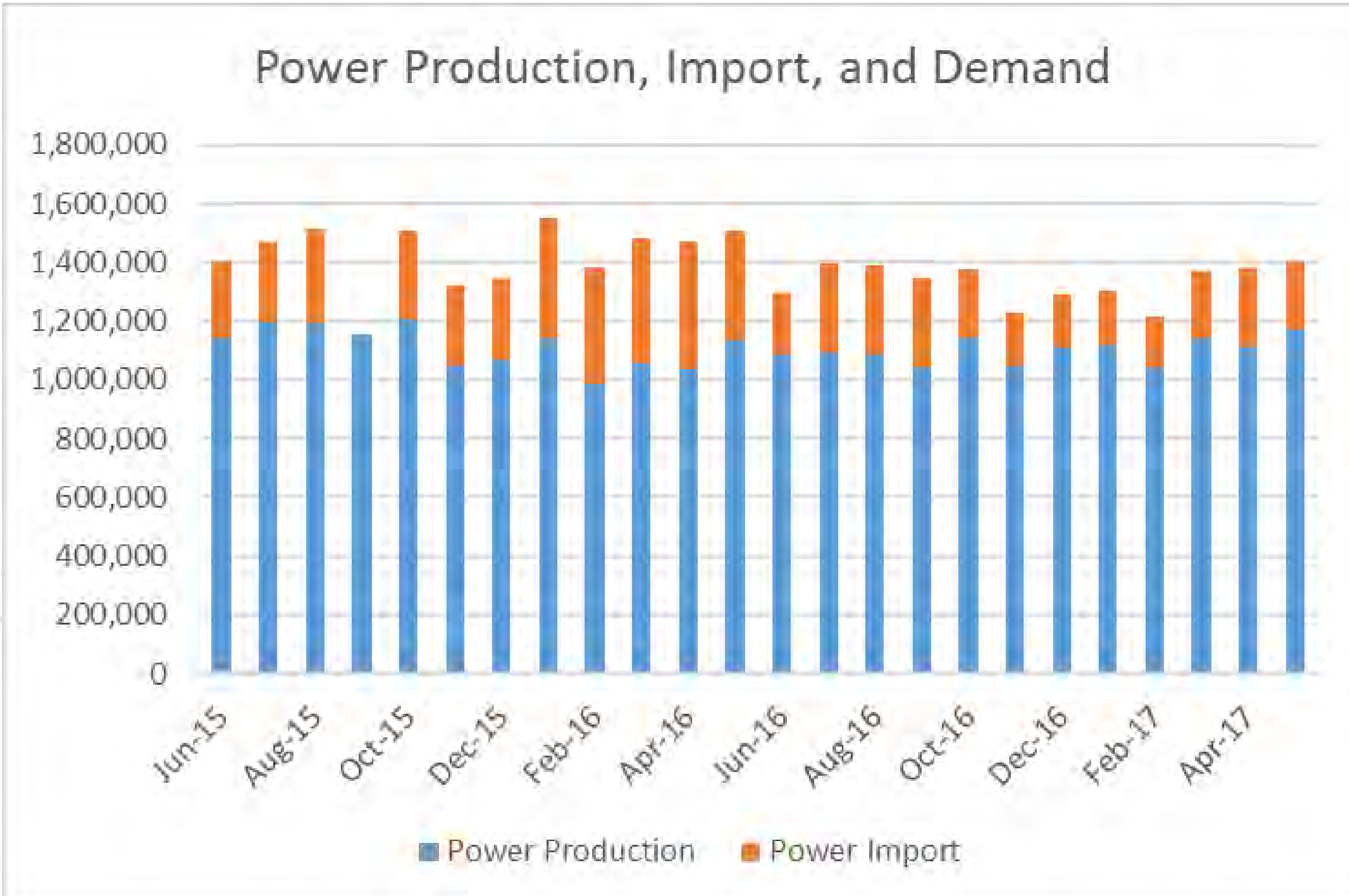
1) What happened November 2015? DG outage?
2) Divergence of "total gas production" from sum of other meters
3) When DG is sent to the heat dryer, what contributes to flaring?
4) Flared gas, over the course of the last year, represents 179 kW of "potential" power production

Natural Gas Usage Summary – Last 2 years



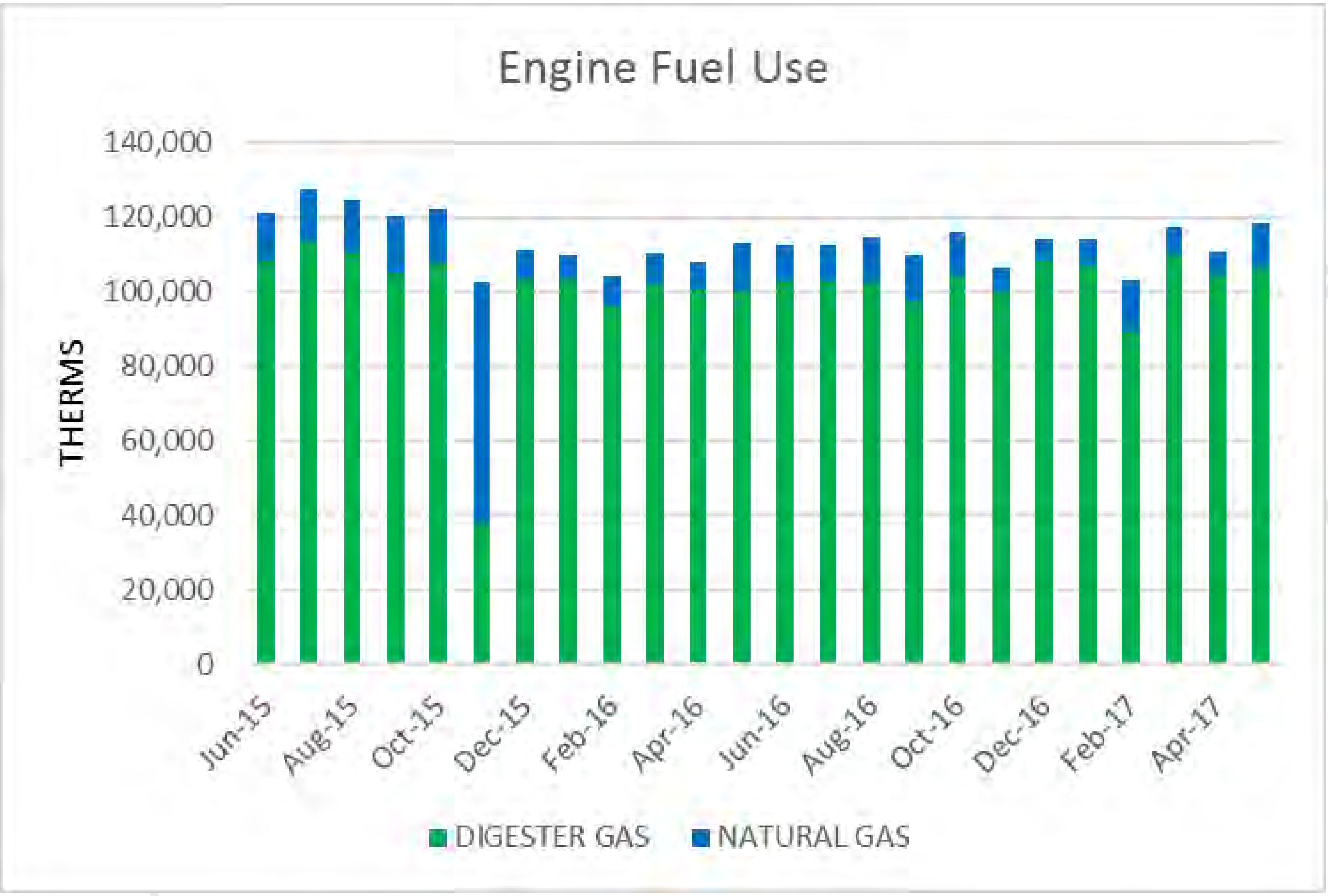
1) What is the NG control strategy to cogen? Why is there NG contribution to cogen in months where DG is being sent to dryer or flare?

Power Production and Import – Last 2 years



1) Consistently operating at 2-engine output
2) Operating a third engine at full output (if DG production increases and/or permit is modified) would result in power export

Engine Fuel Use– Last 2 years



1) Consistent operation
2) What is NG blending strategy?

Screening of Technologies

Fatal Flaw Filter

- Applied uniformly across all technologies
- Four criteria:
  - At least one successful North American installation of technology
  - At least one successful installation in a facility of similar size
  - Available space
  - Compatibility with plant size and any existing equipment

Evaluation Criteria

Criterion	Criterion Description	Scoring Description
End Use Market Compatibility	• Onsite technology directly produces one of the recommended product alternatives. • Alternately, onsite technology product is compatible with product alternatives.	• **Low score** indicates technology product that has not been identified as part of the product list nor compatible with the product list. **High score** indicates technology product that is compatible with Class B cake, Class A cake, Class A THP cake, and dried Class A pellet.
Proven Technology Performance	• Proven and reliable technology with same configuration intended at Encina. • Long successful operating track record.	• **Low score** indicates no successful large scale operating installations in North America or Europe, no successful demonstration scale installations in North America or Europe, and unknown safety or reliability record. • **High score** indicates more than one successful operating installation in North America or Europe, more than one operating installation at a WWTP of at least 40 mgd in North America or Europe, track record duration > 5 years, and vendors in Western USA.
Minimize Life Cycle Costs	• Qualitative metric of program cost. • Capital and O&M costs based on existing Encina data or similar experience at other WWTPs. • Potential revenues from sales. • Product/market geographic proximity.	• **Low score** indicates high capital cost to build onsite facilities, high O&M costs, expensive end use market, and high transportation costs. • **High score** indicates low capital cost to build onsite facilities, low O&M costs, potential product revenue, and product destination within 100 miles.

Evaluation Criteria (cont.)

Criterion	Criterion Description	Scoring Description
Energy/Resource Recovery	• Increases biogas production through advanced digestion. • Supports co-digestion of organic waste. • Recovery of renewable energy. • Beneficial use of biosolids product.	• **Low score** indicates high energy requirement for onsite technology, no increase in biogas production, technology does not recover energy as biogas, no recovery of renewable energy in biosolids, and no biosolids resource recovery. • **High score** indicates a higher biogas production, compatible with co-digestion of organic waste, and biosolids resource recovery.
O&M Impacts	• Impacts to existing plant O&M staff levels. • Complexity of new technology O&M and control systems. • Reliability of new technology (potential downtime). • Minimal impacts to plant safety.	• **Low score** indicates more O&M time required, complex mechanical and control systems required compared with existing plant facilities, potential equipment downtime, and new chemicals or hazards. • **High score** indicates reduction in O&M staff time required, new technology is simple to operate and maintain, reliable with minimal downtime, and no new chemicals or hazards.

Evaluation Criteria (cont.)

Criterion	Criterion Description	Scoring Description
Environmental Impacts	• Impacts to carbon footprint and air permitting.	• **Low score** indicates high carbon footprint for technology, high travel distance to end use, difficult to treat side-streams or impacts to GWRS, and new permitting for environmental regulatory requirements. • **High score** indicates low carbon footprint for technology, low travel distance to end use, minimal side-stream generation or impacts, no additional permitting for environmental regulatory requirements.
Community & Stakeholder Impacts	• Minimize nuisance impacts such as dust, odors, vectors, aesthetics, noise and traffic. • Assess impacts to partner agency issues/values as well as local planning codes and requirements.	• **Low score** indicates nuisance factors for onsite technology are difficult to mitigate. • **High score** indicates nuisance factors can be mitigated at plant site.
Project Site Compatibility	• Assess compatibility of technology with available plant footprint. • Incorporation into existing treatment process. • Ability to accept co-digestion substrates.	• **Low score** indicates lack of site space for new facilities, requires abandonment of existing facilities, and difficult integration with existing plant. • **High score** indicates available footprint for new facilities and maintains space for future facilities, easy of integration with existing processes and facilities.

Evaluation Criteria Weighting

Criterion	Weight Stabilization	Weight Dewatering	Weight Biogas Use and Waste Heat
End Use Market Compatibility	15%	15%	NA
Proven Technology Performance	15%	25%	20%
Minimize Life Cycle Costs	10%	20%	10%
Energy/Resource Recovery	20%	NA	25%
O&M Impacts	10%	15%	10%
Environmental Impacts	10%	5%	15%
Community & Stakeholder Impacts	10%	5%	10%
Project Site Compatibility	10%	15%	10%

Thickening Technologies

- Primary Clarifier (Existing)
- DAFT (Existing)
- Rotary Drum Thickener (RDT)
- Recommendation from prior planning efforts used to evaluate RDTs compared to status quo

Starting with the End in Mind – Market Compatibility

- Class B Cake – Land application (Arizona) or contract composting
- Class A Cake – Land application in CA and AZ (soil blending and land reclamation possible)
- Class A THP Cake – Land application and soil blending (land reclamation possible)
- Class A granules (high quality) – Land application, horticulture, fertilizer blending, soil blending (land reclamation possible)
- Class A granules (low quality) – Land application (land reclamation possible)
- Class A Lystegro – Land application

Options to produce end-use product alternatives

Product Alternatives	Technology Options
Class B Cake	Class B digestion
Class A Cake	Class A digestion (thermophilic or TPAD)
Class A THP Cake	THP/digestion
Class A Dried Granule (high quality)	Class A or B digestion + two dryer trains
Class A Dried Granule (low quality)	Class A or B digestion + maximize existing dryer
Class A Lystegro	Class A or B digestion + Lystek

Stabilization Technologies

- Mesophilic Digestion
- Mesophilic High Solids Digestion
- Staged Digestion
- Acid/Gas Digestion
- Thermophilic Digestion
- Temperature Phased Anaerobic Digestion (TPAD)
- Enzymatic Hydrolysis
- Chemical Hydrolysis
- Lystek
- Thermal Hydrolysis Process (THP) – Traditional CAMBI
- THP – Digestion-Lysis-Digestion (DLD)
- THP – Solid Stream CAMBI

Stabilization Technologies – Fatal Flaw

	Technology Maturity	Successful Operation of Comparable Size	Available Space	Compatibility
Mesophilic Digestion	Pass	Pass	Pass	Pass
Mesophilic with High Solids	Pass	Pass	Pass	Pass
Staged Digestion	Pass	Pass	Fail	Pass
Acid/Gas Phased Digestion	Pass	Pass	Fail	Pass
Thermophilic Digestion	Pass	Pass	Pass	Pass
Temperature Phased Anaerobic Digestion	Pass	Pass	Fail	Pass
Enzymatic Hydrolysis	Fail	Fail	Pass	Pass
Chemical Hydrolysis	Pass	Fail	Pass	Pass
Lystek	Pass	Pass	Pass	Pass
Traditional CAMBI	Pass	Pass	Pass	Pass
THP - DLD	Fail	Fail	Fail	Pass
Solid Stream CAMBI	Fail	Fail	Pass	Pass

Stabilization Technologies - Screening

	Mesophilic Digestion	Mesophilic Digestion with High Solids	Thermophilic Digestion	Lystek	Traditional CAMBI
End Use Market Compatibility	3	3	3	2	5
Proven Technology Performance	5	2	5	2	4
Minimize Life Cycle Costs	3	3	4	2	2
Energy/Resource Recovery	3	4	5	3	4
O&M Impacts	4	3	4	3	3
Environmental Impacts	4	4	4	3	4
Community & Stakeholder Impacts	4	4	4	2	4
Project Site Compatibility	5	3	5	3	2
Weighted Score	**3.80**	**3.25**	**4.30**	**2.50**	**3.65**

Dewatering Technologies

- Centrifuge
- Belt press
- Screw press
- Rotary press
- Volute press
- Bucher press

Dewatering Technologies – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Centrifuges	Pass	Pass	Pass	Pass
Belt Press	Pass	Pass	Pass	Pass
Screw Press	Pass	Pass	Pass	Pass
Rotary Press	Pass	Pass	Pass	Pass
Volute Press	Pass	Pass	Pass	Pass
Bucher Press	Fail	Fail	Pass	Pass

Dewatering Technologies - Screening

	Centrifuges	Belt Press	Screw Press	Rotary Press	Volute Press
End Use Market Compatibility	3	5	4	3	3
Proven Technology Performance	5	5	3	2	2
Minimize Life Cycle Costs	4	4	3	3	3
O&M Impacts	5	5	2	2	2
Environmental Impacts	3	2	3	3	3
Community & Stakeholder Impacts	4	4	4	4	4
Project Site Compatibility	5	4	2	3	3
Weighted Score	**4.35**	**4.45**	**2.90**	**2.65**	**2.65**

Post-Dewatering Technologies

- Thermal drying – high quality granules
- Thermal drying – low quality granules (indirect dryer)
- Gasification
- Pyrolysis
- Partial solar drying
- Deep well injection
- Dehydration
- Incineration

Post-Dewatering Technologies – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Thermal Drying: Low Quality (Indirect Dryer)	Pass	Pass	Pass	Fail
Thermal Drying: High Quality (Drum Dryer)	Pass	Pass	Pass	Pass
Gasification	Fail	Fail	Pass	Pass
Pyrolysis	Fail	Fail	Pass	Pass

Alternative Power Production Technologies

- Internal Combustion Engines
- Digester gas upgrading
  - For pipeline injection
  - For vehicle fueling (CNG)
- Microturbines
- Biosolids Drying – direct use of biogas
- Energy Storage (Batteries)
- Fuel Cells
- Large Scale Solar Photovoltaics (PV)
- Small Scale/Rooftop Solar Photovoltaics
- Wind Turbines
- Direct sale to adjacent power plant

Alternative Power Production – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Internal Combustion Engines	Pass	Pass	Pass	Pass
Digester Upgrading: Pipeline Injection	Pass	Pass	Pass	Pass
Digester Upgrading: Vehicle Fueling (CNG)	Pass	Pass	Pass	Pass
Microturbines	Pass	Pass	Pass	Pass
Biosolids Drying - Direct Use Of Biogas	Pass	Pass	Pass	Pass
Energy Storage	Pass	Pass	Pass	Pass
Fuel Cells	Fail	Fail	Pass	Pass
Large Scale Solar Photovoltaics	Pass	Pass	Pass	Pass
Small Scale/Rooftop Solar Photovoltaics	Pass	Pass	Pass	Pass
Wind Turbines	Pass	Pass	Fail	Fail

Alternative Power Production – Screening

	Internal Combustion Engines - Status Quo	Internal Combustion Engines - With Gas Conditioning	Internal Combustion Engines - With Exhaust Treatment	Digester Upgrading: Pipeline Injection	Digester Upgrading: Vehicle Fueling (CNG)	Micro-turbines	Biosolids Drying - Direct Use Of Biogas	Energy Storage (Batteries)	Small Scale Rooftop PV	Large Scale Photovoltaics
Proven Technology Performance	5	5	4	2	3	4	5	3	5	5
Minimize Life Cycle Costs	3	3	4	4	4	3	3	3	4	4
Energy/Resource Recovery	4	4	5	4	4	4	2	1	5	5
O&M Impacts	3	4	3	4	4	4	3	4	5	5
Environmental Impacts	3	3	4	5	5	5	3	3	5	4
Community & Stakeholder Impacts	4	4	5	5	5	4	3	3	5	5
Project Site Compatibility	5	5	4	4	4	4	5	3	2	2
Weighted Score	**3.95**	**4.05**	**4.25**	**3.85**	**4.05**	**4.05**	**3.35**	**2.60**	**4.60**	**4.45**

Waste Heat Technologies

- Small Scale Steam Turbines
- Thermo/THP
- Absorption and Adsorption Chillers
- Organic Rankine Cycle (ORC)
- Gasification of Biosolids

Waste Heat Technologies – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Small Scale Steam Turbines	Pass	Pass	Pass	Pass
Use For Thermo/THP	Pass	Pass	Pass	Pass
Absorption And Adsorption Chillers	Pass	Pass	Pass	Fail
Organic Rankine Cycle	Fail	Fail	Pass	Pass
Gasification Of Biosolids	Fail	Fail	Pass	Pass

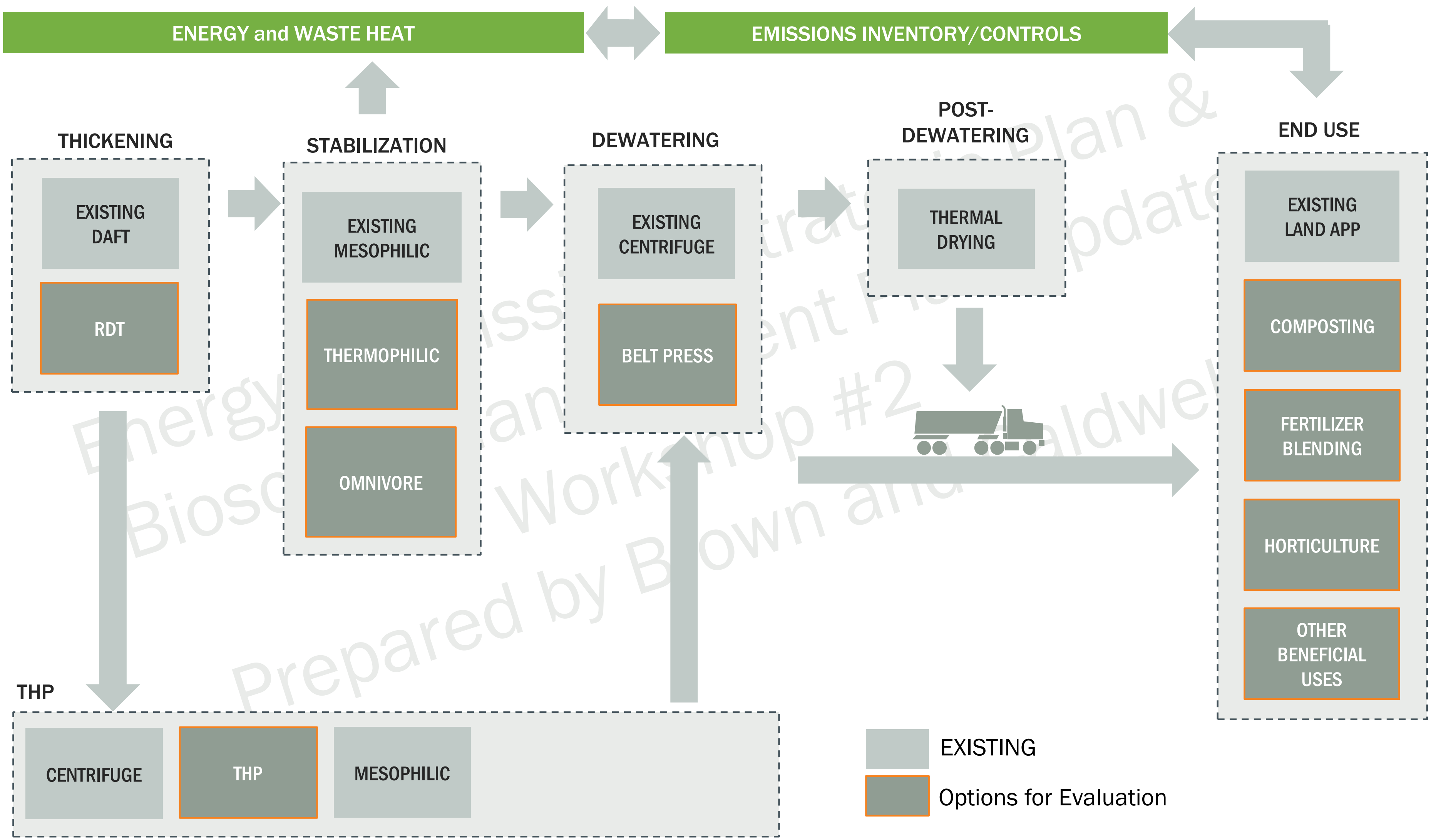
Waste Heat Technologies – Screening

	Small-Scale Steam Turbines	Thermo/THP
Proven Technology Performance	2	5
Minimize Life Cycle Costs	3	5
Energy/Resource Recovery	4	4
O&M Impacts	3	3
Environmental Impacts	3	4
Community & Stakeholder Impacts	3	4
Project Site Compatibility	3	4
Weighted Score	**3.05**	**4.2**

Creation of End to End Alternatives

Brown AND Caldwell

Evaluating Technologies and Markets Together



Initial Alternatives

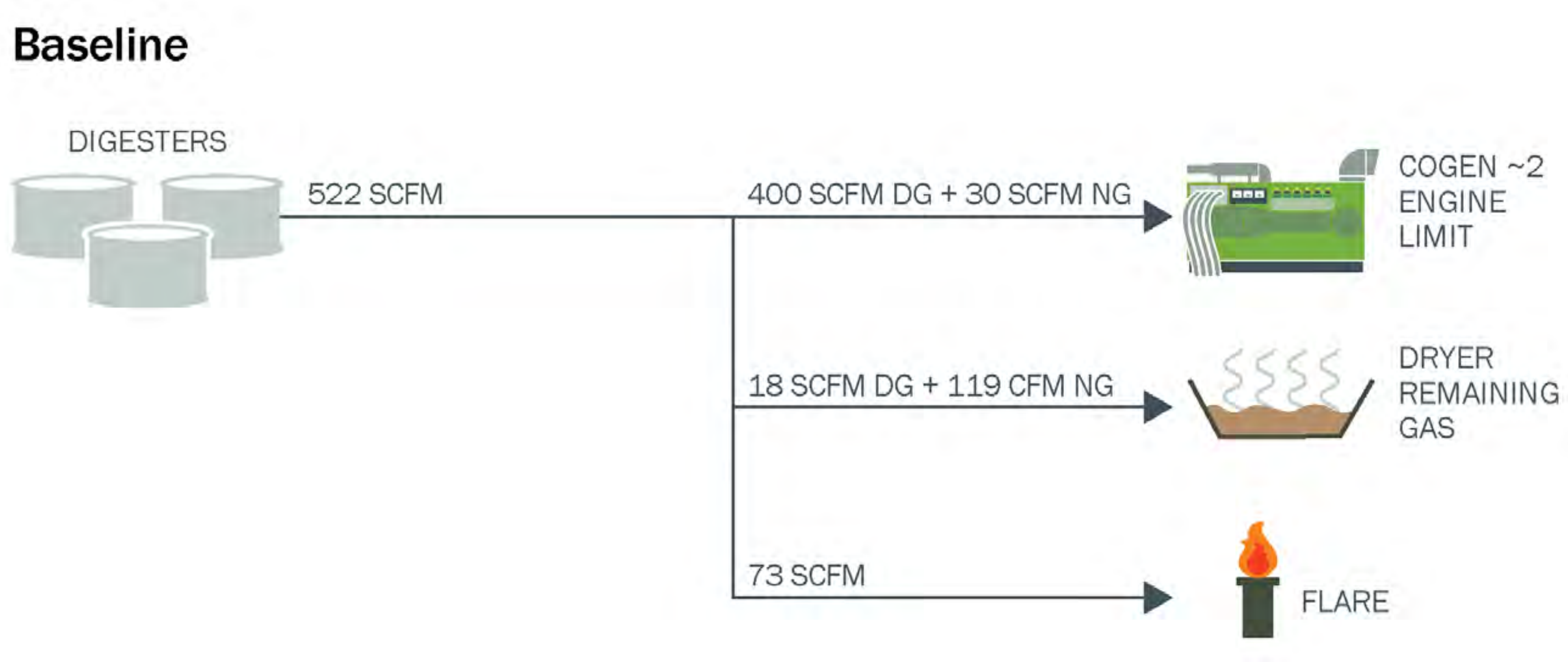
- Meso plus second dryer
- Meso plus Class B hauling
- Thermophilic
  - With and without second dryer
- Cambi (traditional)
  - With and without second dryer

- Additional Layers
  - Thickening
  - Dewatering
  - Energy alternatives
  - End use markets

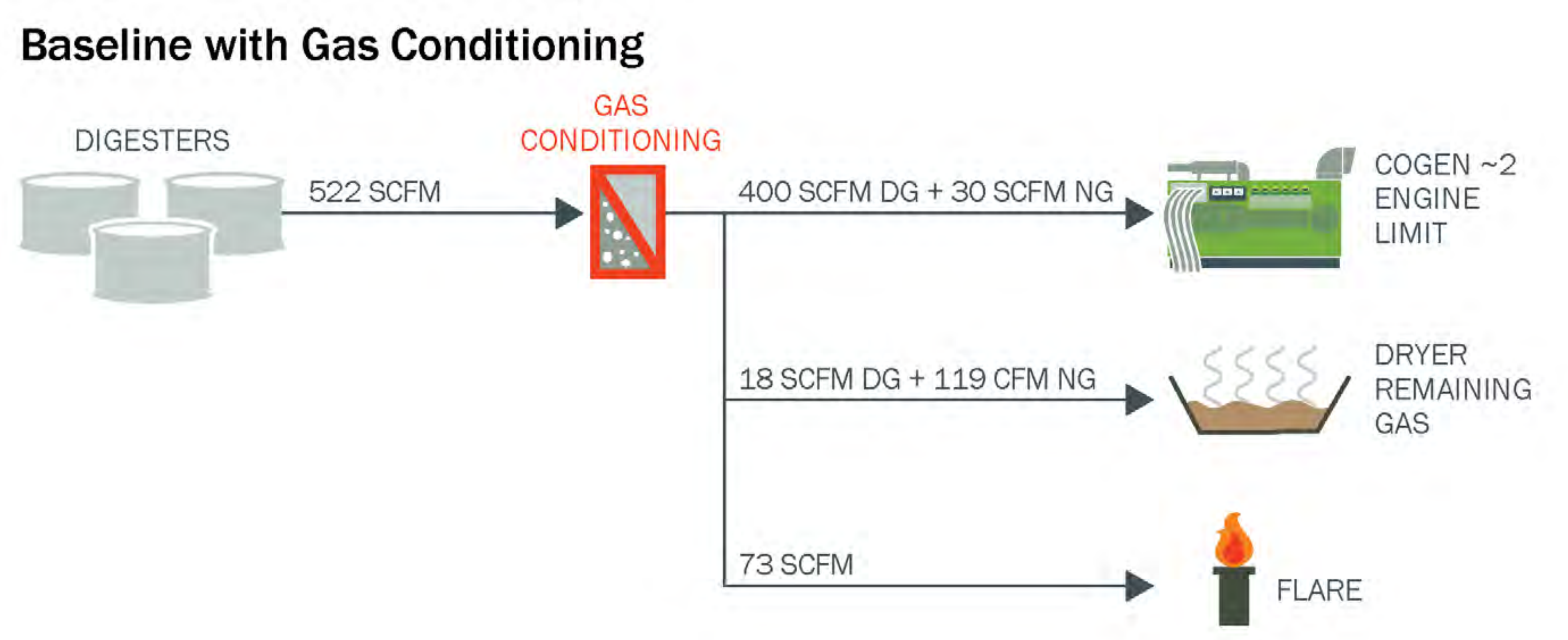
Alternatives: Power Production

- Baseline: Existing cogen + drying
- Baseline + gas conditioning
  - Gas conditioning serves to reduce O&M costs associated with engines and dryer
- Existing cogen + vehicle fuel (via pipeline injection or tube trailer)
  - No permit modification to cogen / no DG to dryer
  - Continue to operate two engines
  - Additional gas routed to vehicle fuel
- Existing cogen + microturbines
  - Includes gas conditioning
  - No permit modification to cogen / no DG to dryer
- Existing cogen + steam boiler/turbine
  - No permit modification to cogen / no DG to dryer
  - Additional gas routed to steam boiler; steam used in small turbine
- New cogen permit, CO catalyst and SCR, gas conditioning
  - Need to consider plant demand as a limit on power production
- Vehicle Fuel (primary use of DG) + existing cogen (natural gas + tail gas)
  - "All in" on vehicle fuel

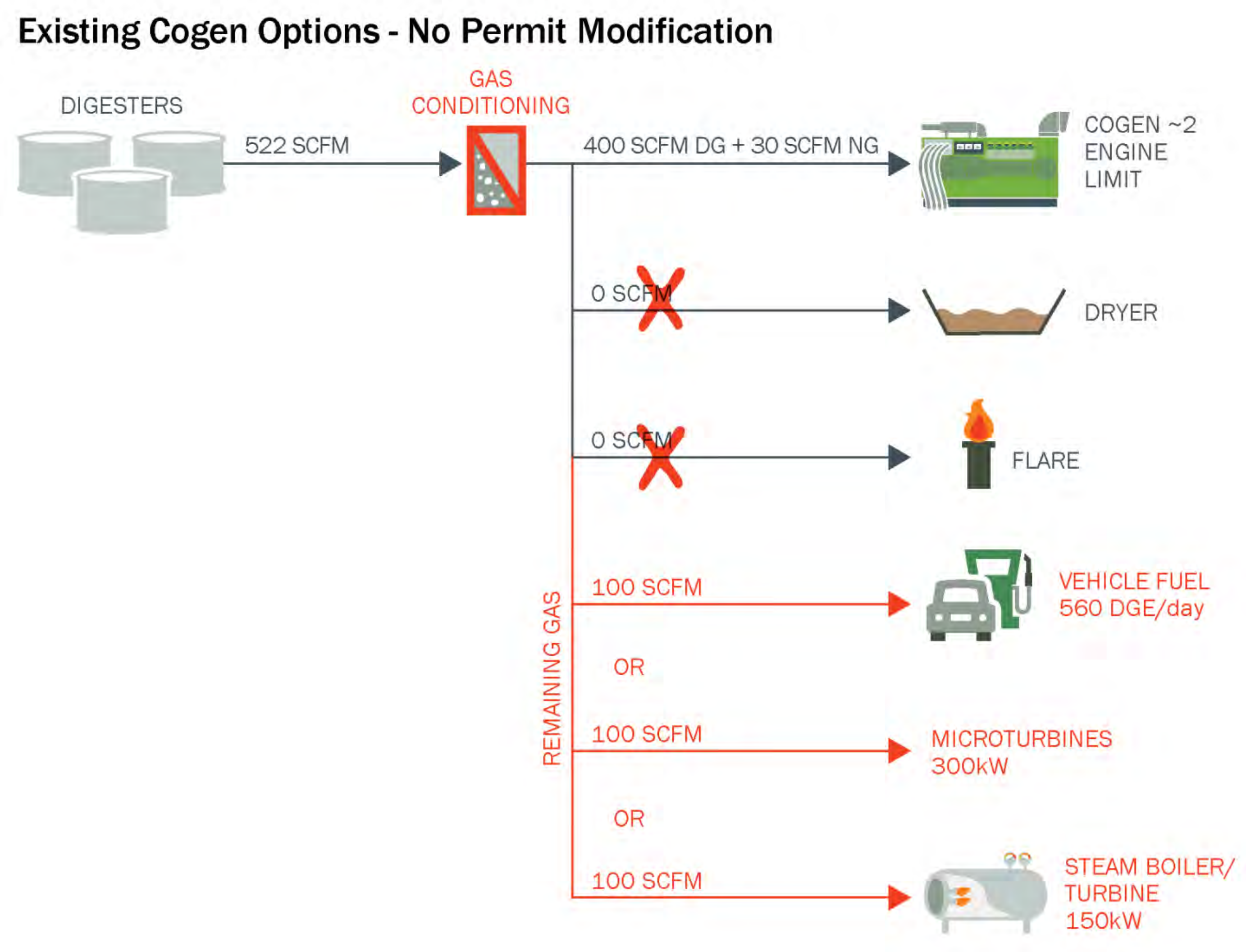
Baseline includes cogeneration (permit limited), dryer and some flaring



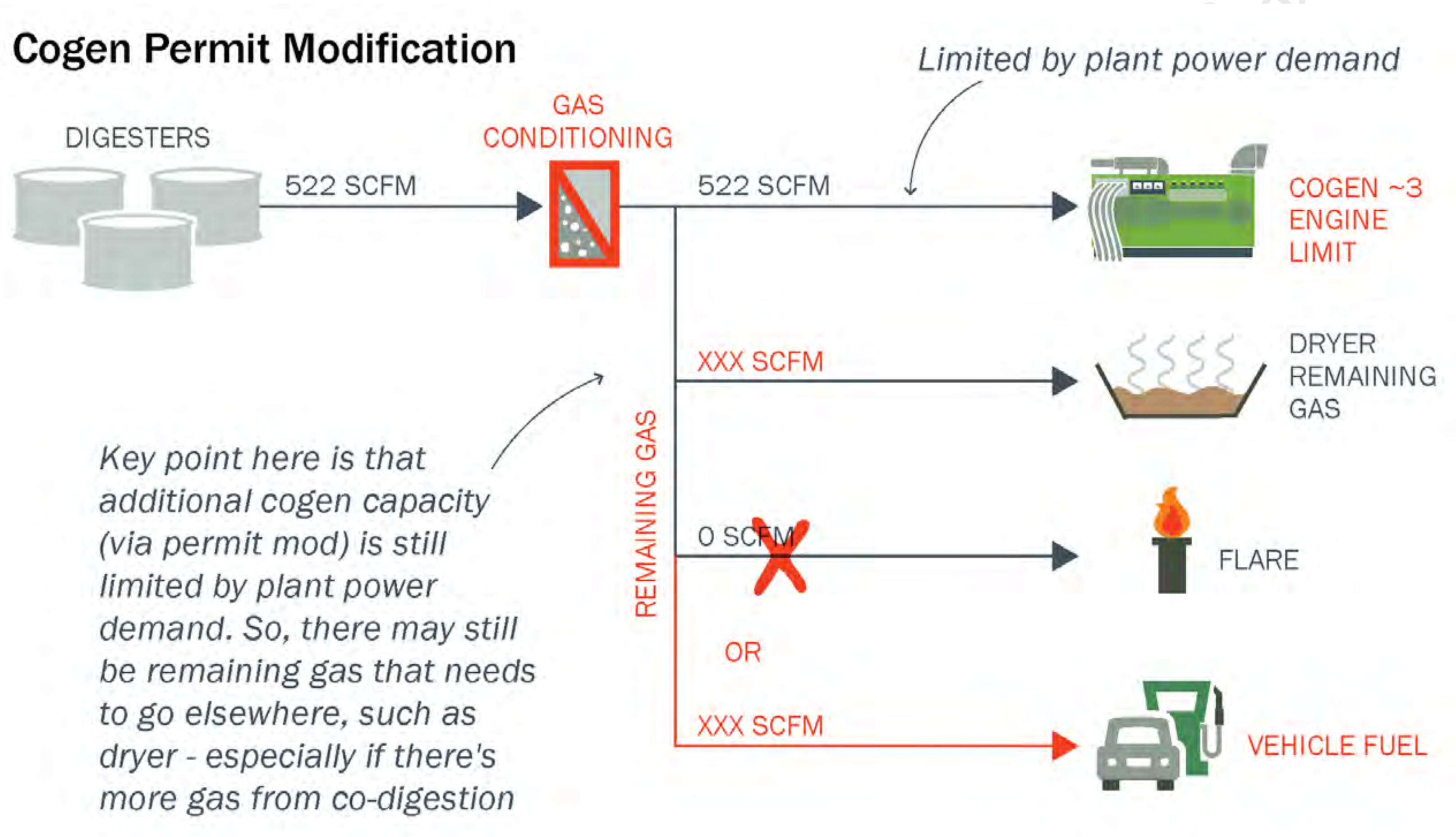
Gas conditioning could reduce engine and dryer O&M costs associated with siloxanes



With the existing permit in place, where else can we send digester gas to get highest value?

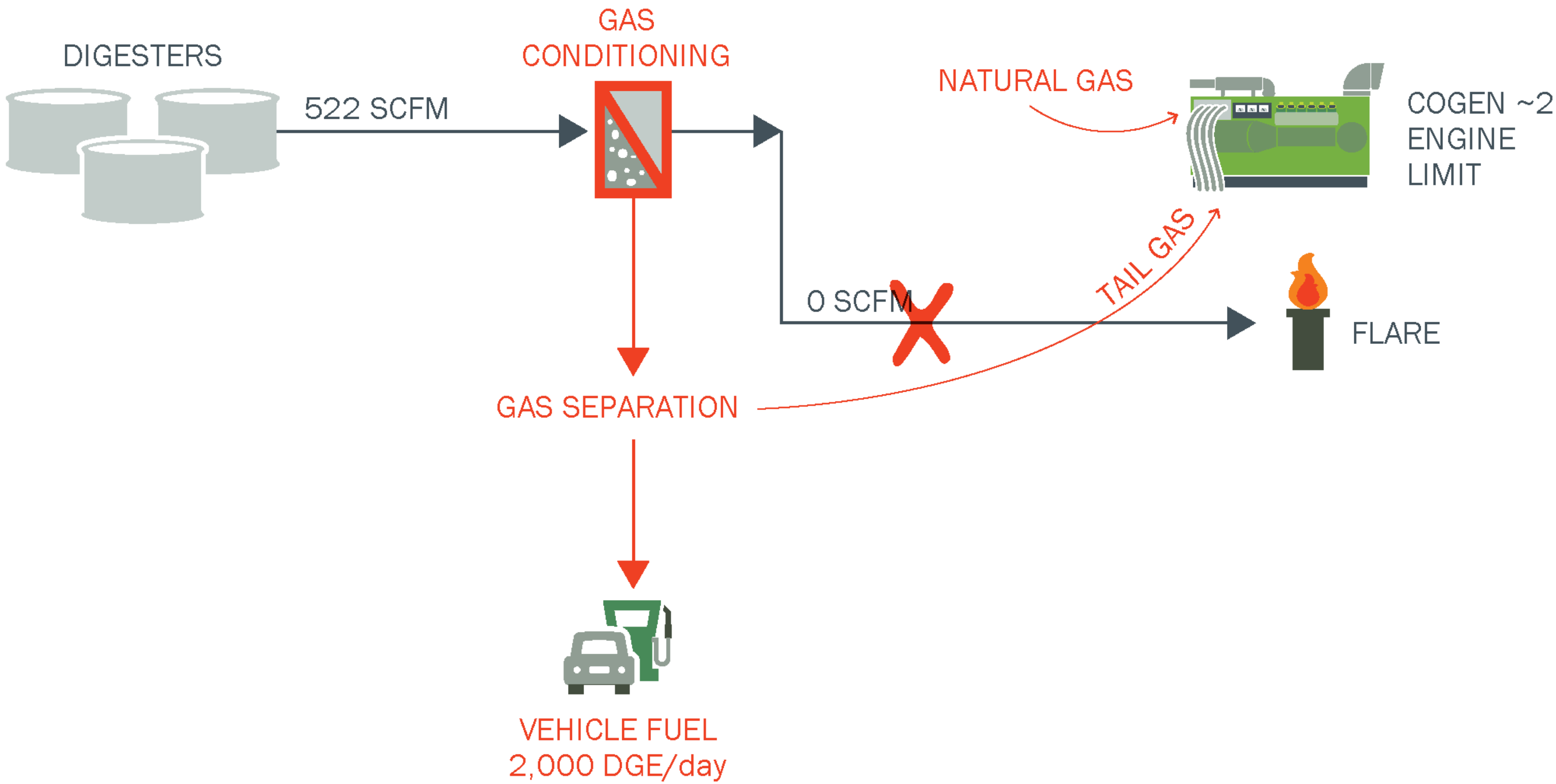


A permit modification allows EWA to meet plant electricity demand, but any additional gas would need to go to a non-generating use



An all-vehicle-fuel option may deliver the best economics

Vehicle Fuel



Alternatives to be presented at next workshop

- Process schematic
- General overview (pros and cons)
- Footprint
- Potential locations

Grant Updates

Self Generation Incentive Program

Program	Self-Generation Incentive Program (SGIP)
Agency	California Energy Commission / administered by SDG&E
Eligible Projects	Self-generation projects such as new engines, microturbines, or steam turbines – increased incentives for renewable/biogas projects; Energy storage / batteries
Funding	Incentives based on anticipated power output – based on fuel availability, not nameplate capacity; 50% paid upfront / 50% paid over 5 years based on performance
Schedule	Funding available each year / first-come, first-served Battery funding decreases as tiers fill up Projects must be operational within 18 months of award
How much are we talking?	~$500k - $1M depending on project size
Recommendation for SWEET Analysis	Don’t count on funding to justify project economics
Next steps	Continue to track / pursue if selected alternatives meet criteria

Low-Carbon Fuel Standard

Program	Low-Carbon Fuel Standard (LCFS)
Agency	California Air Resources Board
Eligible Projects	Part of AB 32 scoping plan – projects that reduce the carbon intensity of California's vehicle fuel – i.e. renewable compressed natural gas (CNG vehicle fuel)
Funding	Incentives based on fuel production, market-based values; Paid on a per-gallon basis as the project performs
Schedule	Ongoing program, recently extended through 2030
How much are we talking?	Varies … could equate to ~$0.50/DGE - $1.00/DGE depending on market factors
Recommendation for SWEET Analysis	Include in SWEET analysis for vehicle fuel projects; Assume funding only through 2030, use conservative values
Next steps	Continue to track / pursue if vehicle fuel is recommended

Renewable Fuel Standard

Program	Renewable Fuel Standard
Agency	US Environmental Protection Agency
Eligible Projects	Renewable fuel projects– i.e. renewable compressed natural gas (CNG vehicle fuel)
Funding	Incentives based on fuel production, market-based values; Paid on a per-gallon basis as the project performs
Schedule	Ongoing program, not guaranteed beyond 2022
How much are we talking?	A lot of uncertainty: Wastewater digester gas is eligible for highest value of RINs – D3 EPA has recently stated that DG from food waste is a lower value – D5 EPA has the ability to set RIN quotas, which drive supply-and-demand, market-based pricing
Recommendation for SWEET Analysis	Include in SWEET analysis for vehicle fuel projects; Assume funding only through 2022, use conservative values
Next steps	Continue to track / pursue if vehicle fuel is recommended

Organics Grant Program

Program	Organics Grant Program
Agency	Department of Resource Recovery and Recycling (CalRecycle)
Eligible Projects	Projects that serve to divert organics (food waste) from landfill – toward anaerobic digestion or composting; recently issued with a food rescue requirement
Funding	Incentives based on project size and potential tons diverted
Schedule	Recently awarded, not expected to reissue for ~18 months
How much are we talking?	Up to $4M per project
Recommendation for SWEET Analysis	Do not include – too competitive to count on
Next steps	Continue to track / pursue if food waste receiving is recommended

Organics Grant Program - Recent Award

Recommendation:
Staff recommends approval of 10 grant awards, as listed in Table 1 below, for $24,000,000.

Table 1. Organics Grant Program Recommended Award – List A

Applicant	County	Total Award
Anaerobic Digestion Projects		
County Sanitation Districts of Los Angeles County	Los Angeles	$4,000,000
HZIU Kompogas SLO, Inc.	San Luis Obispo	$4,000,000
Rialto Bioenergy Facility, LLC	San Bernardino	$4,000,000
	Subtotal	**$12,000,000**
Compost Projects		
City of San Diego	San Diego	$3,000,000
Mid Valley Recycling, LLC	Fresno	$1,875,000
Salinas Valley Solid Waste Authority	Monterey	$1,341,865
Recology Yuba-Sutter *(partially funded)*	Yuba	$2,783,135
	Subtotal	**$9,000,000**
Rural Compost Projects		
Napa Recycling & Waste Services, LLC	Napa	$541,700
South Lake Refuse Company, LLC	Lake	$1,218,026
West Coast Waste *(partially funded)*	Madera	$1,240,274
	Subtotal	**$3,000,000**
	Grand Total	**$24,000,000**

Organics Grant Program - Recent Award

Table 2. Organics Grant Program Recommended Award – List B

Applicant	County	Total Award Requested*
Anaerobic Digestion Projects		
CR&R Incorporated	Riverside	$4,000,000
Contra Costa Waste Services	Contra Costa	$4,000,000
City of Manteca	San Joaquin	$1,500,000
Santa Barbara County	Santa Barbara	$4,000,000
Subtotal		**$13,500,000**
Compost Projects		
Recology Yuba-Sutter *(partially funded)*	Yuba	$216,865
Agromin OC, LLC	San Bernardino	$600,000
Waste Management of Alameda County, Inc.	Alameda	$3,000,000
GreenWaste Recovery, Inc.	Santa Clara	$1,700,000
Burrtec Waste Industries, Inc.	Riverside	$3,000,000
Arakelian Enterprises Inc. DBA Athens Services	San Bernardino	$3,000,000
Best Way Disposal Company, Inc. DBA Advance Disposal Co.	San Bernardino	$2,481,250
Kern County	Kern	$3,000,000
City of Oceanside	San Diego	$1,178,351
Subtotal		**$18,176,466**
Rural Compost Projects		
West Coast Waste *(partially funded)*	Madera	$161,326
Upper Valley Disposal Service	Napa	$1,250,000
Subtotal		**$1,411,326**
	Grand Total	**$33,087,792**

Heathy Soils Program

Program	Healthy Soils Program
Agency	California Department of Food and Agriculture
Eligible Projects	Demonstration projects that sequester carbon and reduce GHG emissions – groups within CASA
Funding	Incentives based on project size and potential GHG benefit
Schedule	Currently accepting applications through September 19 Annual funding program (AB 32 funds), amounts and criteria may vary
How much are we talking?	Up to $3.75M total
Recommendation for SWEET Analysis	Do not include / ancillary benefit to support end use program
Next steps	Continue to track / connect with CASA Science and Research Group for potential partnerships

Green Project Reserve

Program	Green Project Reserve
Agency	California Water Resources Control Board
Eligible Projects	Projects that improve energy efficiency, renewable energy generation, or recycled water production
Funding	A component of Clean Water State Revolving Funding; Green Project Reserve is a "loan forgiveness" program CWSRF is generally oversubscribed, but GPR is underutilized
Schedule	Ongoing
How much are we talking?	Up to $4M per project, or 50% of project value, whichever is higher
Recommendation for SWEET Analysis	Do not include
Next steps	Something for EWA to keep in mind – if a larger capital project requires funding, consider CWSRF and adding an eligible GPR component

Air Permitting Discussion

Brown AND Caldwell

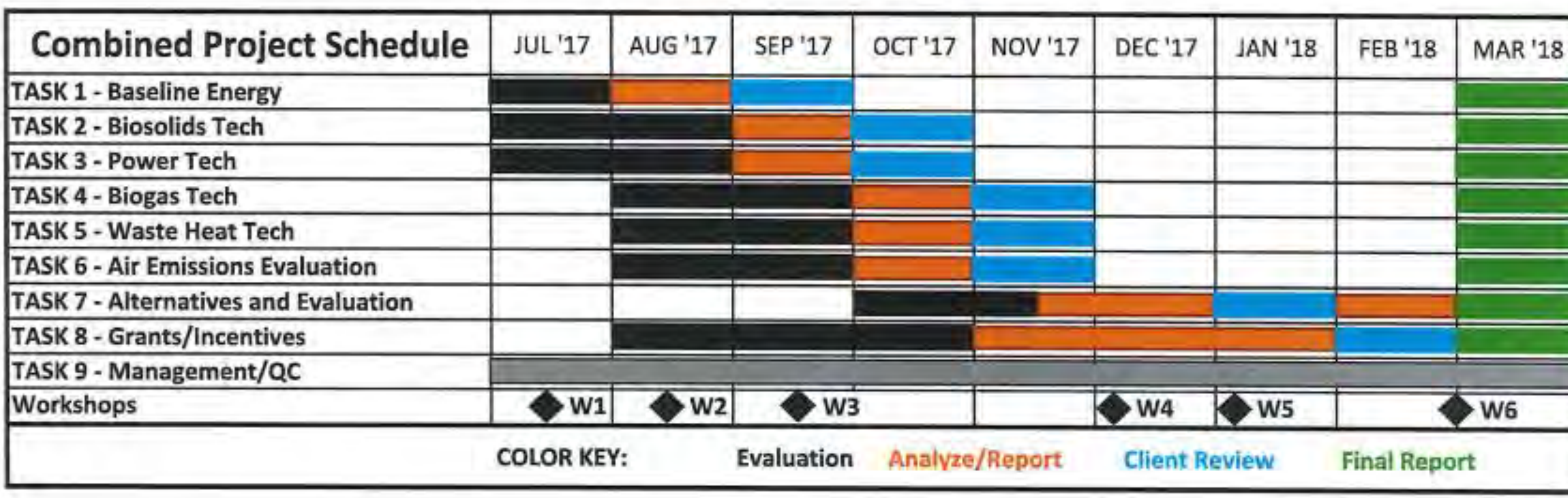
EWA is actively pursuing air permit modification

- EWA (with Don King) will submit a request for permit modification within ~1 week
- Goal is to adjust the CO emission rate from 530 ppm to ~400 ppm, and thereby adjust the fuel input limit aimed at keeping CO emissions below Title V synthetic minor threshold
- If successful, this effort would increase permitted cogen capacity by ~20%
- This increase would allow EWA to meet plant electricity demand with current digester gas flows and cogen system

Look Ahead & Wrap-Up

Project Schedule

- Workshop #3 in mid-September
- Draft Analysis and Reports to Begin



Look Ahead – September Workshop

- Consensus on mass balance/baseline
- Conceptual layouts/details of alternatives for consensus/feedback (example numbers to support including biogas production, food waste that can be imported)
- Air permitting impacts on power production alternatives
- Informational meeting with waste haulers
- Debrief on Anaergia meeting
- Grants update

Wrap-Up

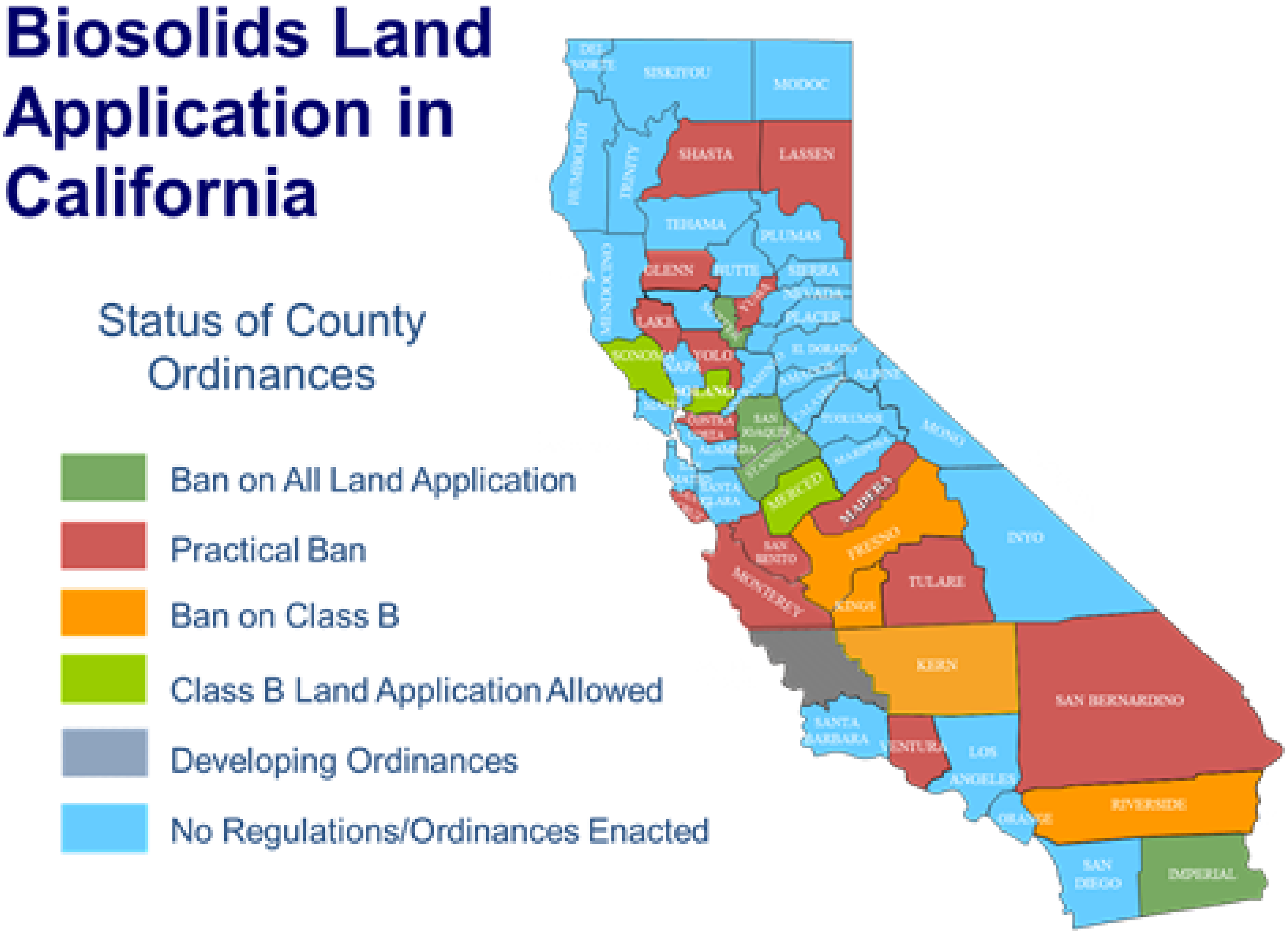
QUESTIONS?

it's about connecting

Brown AND Caldwell : essential ingredients®

Attachment B: Map of California Land Application Ordinances

Source: California Association of Sanitation Agencies



2015 CASA California County Biosolids Map (CASA, 2016)

Attachment C: Digestion Volume Calculations

Pre-THP Dewatering

Assumptions:

Pre-THP dewatering feed solids flows and loads are the same as the digester feed flows and loads on the Digestion tab.

Current solids flows and loads from "Peaking" tabs. 2040 flows and load provided by Tracy Chouinard.

	Current				2040			
Pre-THP Dewatering Fee	Avg	Max Month	Max 2-Week	Max Day	Avg	Max Month	Max 2-Week	Max Day
TS (lb/day)	94,380	109,731	138,681	138,681	108,100	132,000	139,500	170,800
VS (lb/day)	80,520	92,715	97,111	97,111	91,415	111,676	118,019	144,543
%TS	4.52%	4.85%	5.85%	4.15%	4.68%	4.67%	4.67%	4.67%
Flow (GPD)	250,425	271,335	284,379	400,440	277,250	338,974	358,205	438,946

Pre-THP Dewatering Centrifuge 330 gpm

Flow (gpm)	174	188	197	278	193	235	249	305
No. of Duty Unit	0.53	0.57	0.60	0.84	0.58	0.71	0.75	0.92
No. of Standby Unit	1	1	1	1	1	1	1	1
Total No. of Unit	2	2	2	2	2	2	2	2
Solids capture rate	98%	98%	98%	98%	98%	98%	98%	98%
Solids to THP (ppd)	92,492	107,536	135,908	135,908	105,938	129,360	136,710	167,384

Centrifuge Recommendation

Recommend two 29inch bowl units Alfa Laval G3-125 dimensions: 5' x 23'

Cambi THP Unit Capacity

	Peak Day	Other
	ton/day	ton/day
B2-1	6.5	6.2
B2-2	13	12.4
B2-3	19.5	18.5
B2-4	26.1	24.8
B6-2	46	43.7
B6-3	70	66.5
B6-4	93	88.4
B12-3	99	94.1
B12-4	119	113.1

THP	Current				2040			
	Avg	Max Month	Max 2-Week	Max Day	Avg	Max Month	Max 2-Week	Max Day
Solids to THP (dtpd)	46.2	53.8	68.0	68.0	53.0	64.7	68.4	83.7

THP Recommendation

Recommend one B6-4 unit

B6-4 dimensions: 27' x 33'

Cake Bin Recommendation

Since 1 B6-4 has sufficient capacity for 2040 peak day solids production, no cake storage is needed.

Cake bins will only need to provide a working volume (~ 30 cy) to feed the THP.

Recommend two cake bins (one per centrifuge), each with a capacity of 50 cy.

Preliminary bin size, each, LxWxH = 14x10x14

Odor Control

SFPUC solids loads 220 dtpd, odor control (biofilter) approximately 60 x 90

Encina solids loads 84 dtpd, assume odor control will be 1/3 of SFPUC, say 60 x 30

Digester Sizing

Summary of Results

	Current	2040
Conventional Mesophilic Anaerobic Digestion (CMAD)	Existing digesters have sufficient capacity for current flows and loads	Service condition HRT is slight less than 15 days (14.7 days) with existing digesters. Probably ok.
Thermophilic Anaerobic Digestion (TAD)	Existing digesters have sufficient capacity for current flows and loads	Service condition HRT is slight less than 15 days (14.7 days) with existing digesters. Probably ok.
Class A Batch Tanks	Need 4 new batch tanks (0.48 MG each) or, 3 new batch tanks (0.3 MG each) and retrofit 3 existing small digesters (0.3 MG each)	Need 4 new batch tanks (0.48 MG each) or, 3 new batch tanks (0.3 MG each) and retrofit 3 existing small digesters (0.3 MG each)
Staged Mesophilic Anaerobic Digestion (SMAD)	One new digester is required to operate in SMAD mode. Typical operation would be three first stage and one second stage digesters. Piping configuration should allow one of the first stage digesters function as second stage digester.	One new digester is required to operate in SMAD mode. Typical operation would be three first stage and one second stage digesters. Piping configuration should allow one of the first stage digesters function as second stage digester.
Acid/Gas Anaerobic Digestion (AGAD)	Requires two acid reactors, 400,000 gallons each. Preliminary sizing: 45' dia. 34' SWD. Existing digesters have sufficent capacity to function as gas reactors.	Requires two acid reactors, 400,000 gallons each. Preliminary sizing: 45' dia. 34' SWD. Existing digesters will function as gas reactors. Service condition HRT is slightly less than 15 days (14.8 days). Should be ok.
Temperature Phased Anaerobic Digestion (TPAD)	Existing digesters have sufficient capacity for current flows and loads to operate in TPAD mode. Typical operation would be two thermophilic digesters and one mesophilic digester. Equipment and piping configuration should allow one thermophilic digester operate as a swing digester.	Typical operation would be two thermophilic digesters and one mesophilic digester. Equipment and piping configuration should allow one thermophilic digester operate as a swing digester. With existing digesters, HRT at the service conditon is lower than design values. Thermophilic phase HRT is 7.4 days, the potential for microorganism washout is high. Recommend building one new thermophilic phase digester.

Current solids flows and loads from "Peaking" tabs. 2040 flows and load provided by Tracy Chouinard

	Current				2040			
Digester Feed	Avg	Max Month	Max 2-Week	Max Day	Avg	Max Month	Max 2-Week	Max Day
TS (lb/day)	94,380	109,731	138,681	138,681	108,100	132,000	139,500	170,800
VS (lb/day)	80,520	92,715	97,111	97,111	91,415	111,676	118,019	144,543
%TS	4.52%	4.85%	5.85%	4.15%	4.68%	4.67%	4.67%	4.67%
Flow (GPD)	250,425	271,335	284,379	400,440	277,250	338,974	358,205	438,946

Existing Digesters

Digester Diameter	2@ 105, 1@95
SWD	2@35, 1@42.8
Volume, cf	274,064
Volume, gal	2,050,000
No. of Digesters	3
Total Digester Volume, gal	6,150,000

Digester Diam	50
SWD	
Volume, cf	40,107
Volume, gal	300,000
No. of Digeste	3
Total Digester	900,000

Old digester 2 is working as a sludge holding tank. Digesters 1 and 3 are the same size but needs major repair

Conventional Mesophilic Anaerobic Digestion (CMAD)

Design Criteria

Digestion		Average	Service	Max 2-Week
OLR	lb VS/d/cf	0.15	0.18	0.18
HRT	day	15	15	15

Annual Average Condition: AA flows and loads, all digesters in service
Service Condition: AA flows and loads, one digester out of service
Max 2-Week Condition: Peak 14-d flows and loads, all digesters in service

Digester loading rates with three total digesters.

Digester Loading Rates	Current			2040		
	Avg	Service	Max 2-Week	Avg	Service	Max 2-Week
No. of digesters in service	3	2	3	3	2	3
Total digester capacity in service, MG	6.15	4.10	6.15	6.15	4.10	6.15
OLR, lb VS/cf	0.10	0.15	0.12	0.11	0.17	0.14
HRT, day	24.6	16.4	21.6	22.2	14.8	17.2
OLR Check	OK	OK	OK	OK	OK	OK
HRT Check	OK	OK	OK	OK	Overload	OK

Thermophilic Anaerobic Digestion (TAD)

Design Criteria

Digestion		Average	Service	Max 2-Week
OLR	lb VS/d/cf	0.3	0.35	0.30
HRT	day	15	15	15

Annual Average Condition: AA flows and loads, all digesters in service
Service Condition: AA flows and loads, one digester out of service
Max 2-Week Condition: Peak 14-d flows and loads, all digesters in service

Digester loading rates with three total digesters.

Digester Loading Rates	Current			2040		
	Avg	Service	Max 2-Week	Avg	Service	Max 2-Week
No. of digesters in service	3	2	3	3	2	3
Total digester capacity in service, MG	6.15	4.10	6.15	6.15	4.10	6.15
OLR, lb VS/cf	0.10	0.15	0.12	0.11	0.17	0.14
HRT, day	24.6	16.4	21.6	22.2	14.8	17.2
OLR Check	OK	OK	OK	OK	OK	OK
HRT Check	OK	OK	OK	OK	Overload	OK

Class A Batch Tank

Design Criteria

Digestion		Average	Service	Max 2-Week	Max Day
OLR	lb VS/d/cf	N/A	N/A	N/A	N/A
HRT	day	1	1	1	1

Annual Average Condition: AA flows and loads, all digesters in service
Service Condition: AA flows and loads, one digester out of service
Max 2-Week Condition: Peak 14-d flows and loads, all digesters in service

Digester loading rates with four total batch tanks (fill, hold, draw, redundant) (existing digesters 1-3, 0.3 MG each, plus one new the same size)

Digester Loading Rates	Current				2040			
	Avg	Service	Max 2-Week	Max Day	Avg	Service	Max 2-Week	Max Day
No. of digesters in service	1	1	1	1	1	1	1	1
Total digester capacity in service, MG	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
OLR, lb VS/cf	2.01	2.01	2.42	2.42	2.28	2.28	2.94	3.60
HRT, day	1.2	1.2	1.1	0.75	1.1	1.1	0.8	0.68
OLR Check	OK	OK	OK	OK	OK	OK	OK	OK
HRT Check	OK	OK	OK	Overload	OK	OK	Overload	Overload

Staged Mesophilic Anaerobic Digestion (SMAD)

Design Criteria

First Stage		Average	Service	Max 2-Week
OLR	lb VS/d/cf	0.15	0.18	0.18
HRT	day	10	10	10
Second Stage		Average	Service	Max 2-Week
OLR	lb VS/d/cf	N/A	N/A	N/A
HRT	day	5	5	5

Annual Average Condition: AA flows and loads, all digesters in service
Service Condition: AA flows and loads, one digester out of service
Max 2-Week Condition: Peak 14-d flows and loads, all digesters in service

Digester loading rates with existing three digesters (two first stage and one second stage)

Digester Loading Rates	Current			2040		
First Stage Digester	Avg	Service	Max 2-Week	Avg	Service	Max 2-Week
No. of digesters in service	2	1	2	2	1	2
Total digester capacity in service, MG	4.10	2.05	4.10	4.10	2.05	4.10
OLR, lb VS/cf	0.15	0.29	0.18	0.17	0.33	0.22
HRT, day	16.4	8.2	14.4	14.8	7.4	11.4
OLR Check	OK	Overload	OK	Overload	Overload	Overload
HRT Check	OK	Overload	OK	OK	Overload	OK
Second Stage Digester	Avg	Service	Max 2-Week	Avg	Service	Max 2-Week
No. of digesters in service	1	1	1	1	1	1
Total digester capacity in service, MG	2.05	2.05	2.05	2.05	2.05	2.05
OLR, lb VS/cf	N/A	N/A	N/A	N/A	N/A	N/A
HRT, day	8.2	8.2	7.2	7.4	7.4	5.7
OLR Check	N/A	N/A	N/A	N/A	N/A	N/A
HRT Check	OK	OK	OK	OK	OK	OK

Digester loading rates with four digesters (three first stage and one second stage)

Digester Loading Rates	Current			Current		
First Stage Digester	Avg	Service	Max 2-Week	Avg	Service	Max 2-Week
No. of digesters in service	3	2	3	3	2	3
Total digester capacity in service, MG	6.15	4.10	6.15	6.15	4.10	6.15
OLR, lb VS/cf	0.10	0.15	0.12	0.11	0.17	0.14
HRT, day	24.6	16.4	21.6	22.2	14.8	17.2
OLR Check	OK	OK	OK	OK	OK	OK
HRT Check	OK	OK	OK	OK	OK	OK
Second Stage Digester	Avg	Service	Max 2-Week	Avg	Service	Max 2-Week
No. of digesters in service	1	1	1	1	1	1
Total digester capacity in service, MG	2.05	2.05	2.05	2.05	2.05	2.05
OLR, lb VS/cf	N/A	N/A	N/A	N/A	N/A	N/A
HRT, day	8.2	8.2	7.2	7.4	7.4	5.7
OLR Check	N/A	N/A	N/A	N/A	N/A	N/A
HRT Check	OK	OK	OK	OK	OK	OK

Acid-Gas Digestion (AGAD)

Design Criteria

Acid Phase Digester		Average	Service	Max 2-Week	Max Day
OLR	lb VS/d/cf				2
HRT	day				1
Gas Phase Digester		Average	Service	Max 2-Week	
OLR	lb VS/d/cf	0.15	0.18	0.18	
HRT	day	15	15	15	

Annual Average Condition: AA flows and loads, all digesters in service
Service Condition: AA flows and loads, one digester out of service
Max 2-Week Condition: Peak 14-d flows and loads, all digesters in service
Max Day Condition: For acid phase reactor sizing only

Acid Phase Digester

Digester Loading Rates	Current (2012-2016)				Current (2012-2016)			
	Avg	Service	Max 2-Week	Max Day	Avg	Service	Max 2-Week	Max Day
No. of digesters in service	2	1	2	2	2	1	2	2
Total digester capacity in service, MG	0.60	0.30	0.60	0.60	0.60	0.30	0.60	0.60
OLR, lb VS/cf	1.00	2.01	1.21	1.21	1.14	2.28	1.47	1.80
HRT, day	2.40	1.20	2.11	1.50	2.16	1.08	1.68	1.37

Digester loading rates with three gas phase digesters

Digester Loading Rates	Current (2012-2016)			Current (2012-2016)		
	Avg	Service	Max 2-Week	Avg	Service	Max 2-Week
No. of digesters in service	3	2	3	3	2	3
Total digester capacity in service, MG	6.15	4.10	6.15	6.15	4.10	6.15
OLR, lb VS/cf	0.10	0.15	0.12	0.11	0.17	0.14
HRT, day	24.6	16.4	21.6	22.2	14.8	17.2
OLR Check	OK	OK	OK	OK	OK	OK
HRT Check	OK	OK	OK	OK	Overload	OK

Temperature Phased Anaerobic Digestion (TPAD)

Design Criteria

Thermophilic Digester		Average	Service	Max 2-Week
OLR	lb VS/d/cf	0.35	0.35	0.35
HRT	day	9	8	8
Mesophilic Digester		Average	Service	Max 2-Week
OLR	lb VS/d/cf	N/A	N/A	N/A
HRT	day	7	7	7

Annual Average Condition: AA flows and loads, all digesters in service
Service Condition: AA flows and loads, one digester out of service
Max 2-Week Condition: Peak 14-d flows and loads, all digesters in service

Digester loading rates with existing three digesters (two thermo and one meso)

Digester Loading Rates	Current			Current		
Thermophilic Digester	Avg	Service	Max 2-Week	Avg	Service	Max 2-Week
No. of digesters in service	2	1	2	2	1	2
Total digester capacity in service, MG	4.10	2.05	4.10	4.10	2.05	4.10
OLR, lb VS/cf	0.15	0.29	0.18	0.17	0.33	0.22
HRT, day	16.4	8.2	14.4	14.8	7.4	11.4
OLR Check	OK	OK	OK	OK	OK	OK
HRT Check	OK	OK	OK	OK	Overload	OK
Mesophilic Digester	Avg	Service	Max 2-Week	Avg	Service	Max 2-Week
No. of digesters in service	1	1	1	1	1	1
Total digester capacity in service, MG	2.05	2.05	2.05	2.05	2.05	2.05
OLR, lb VS/cf	N/A	N/A	N/A	N/A	N/A	N/A
HRT, day	8.2	8.2	7.2	7.4	7.4	5.7
OLR Check	N/A	N/A	N/A	N/A	N/A	N/A
HRT Check	OK	OK	OK	OK	OK	OK

Brown AND Caldwell

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Technical Memorandum

FINAL

Prepared for: Encina Wastewater Authority

Project Title: Biosolids, Energy and Emissions

Project No.: 150871.003.001

Technical Memorandum No. 3

Subject: Technical Evaluation for Alternative Power Production

Date: December 1, 2017

To: Scott McClelland, Assistant General Manager

From: Scott Lacy

Prepared by: ______________________
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____
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Limitations:

This document was prepared solely for Encina Wastewater Authority in accordance with professional standards at the time the services were performed and in accordance with the contract between Encina Wastewater Authority and Brown and Caldwell dated June 28, 2017. This document is governed by the specific scope of work authorized by Encina Wastewater Authority; it is not intended to be relied upon by any other party except for regulatory authorities contemplated by the scope of work. We have relied on information or instructions provided by Encina Wastewater Authority and other parties and, unless otherwise expressly indicated, have made no independent investigation as to the validity, completeness, or accuracy of such information.

Table of Contents

List of Figures

List of Tables

List of Abbreviations

BC	Brown and Caldwell
BEE Plan	Biosolids Energy and Emissions Plan
Btu	British thermal units
CNG	compressed natural gas
EWA	Encina Wastewater Authority
EWPCF	Encina Water Pollution Control Facility
GHG	greenhouse gas emissions
HSW	high strength waste
IC	internal combustion
kW	kilowatt(s)
lb	pound(s)
LCFS	Low Carbon Fuel Standard
mgd	million gallons per day
MW	megawatt(s)
MWh	megawatts per hour
NEM	net energy metering
NG	natural gas
O&M	operations and maintenance
ppbv	parts per billion by volume
ppmv	parts per million by volume
psig	pounds per square inch gage
PV	photovoltaics
RIN	Renewable Identification Number
scf	standard cubic feet
scfm	standard cubic feet per minute
SCR	selective catalytic reduction
SDG&E	San Diego Gas & Electric
SWEET	Solids Water Energy Evaluation Tool
TM	Technical Memorandum
WWTP	Waste Water Treatment Plant

Executive Summary

The Encina Water Pollution Control Facility (EWPCF) currently has four 750-kilowatt (kW) internal combustion (IC) engines that produce 83 percent of the plant's electrical power demand as well as heat for the wastewater process. The engines are primarily fueled with biogas from the plant's anaerobic digesters, but also pipeline natural gas (NG) under certain scenarios. The engine fuel input, and electric generation output, is limited by an air permit that generally restricts the plant to operation of two engines (biogas fuel), with a third engine (NG fuel) used during peak electric rate periods. Biogas production exceeds the permitted capacity, so excess biogas is directed to the plant's heat dryer or flared. Driven by a high non-coincident power demand cost and a goal to produce 95 percent of power at the plant, Encina Wastewater Authority (EWA) is evaluating alternative power production technologies to reduce costs and recover maximum value from biogas. This Technical Memorandum (TM) 3 describes the development of screening and evaluation criteria for the assessment of alternative power production technologies. Technologies evaluated include IC engines, microturbines, biogas upgrading, solar photovoltaics (PV), battery storage, fuel cells, wind turbines, and sale of biogas to the adjacent Encina Power Station. Screening and ranking of technologies was performed in a workshop with EWA staff on August 16, 2017. Technologies that did not pass the fatal flaw filter were eliminated. Those technologies that passed the fatal flaw filter moved on and were assessed using evaluation criteria developed to reflect EWA's values and project goals, and are summarized in Table ES-1. Power production alternatives that will be further refined and analyzed using Brown and Caldwell's (BC's) Solids Water Energy Evaluation Tool (SWEET) include those that received an overall score of 3 or higher in the scoring evaluation where higher scores are more favorable over low scores and scoring is specific to the EWPCF. Alternatives presented in Table ES-1 can serve as standalone alternatives or be combined to create 'hybrid' alternatives, which may provide the best of both worlds.

Table ES-1. Alternatives Scoring Evaluation

	IC Engines - Status Quo	IC Engines - with Gas Conditioning	IC Engines - with Exhaust Treatment	Biogas Upgrading: Pipeline Injection	Biogas Upgrading: Vehicle Fueling (CNG)	Microturbines	Biosolids Drying	Energy Storage (Batteries)	Small-Scale Rooftop PV	Large-Scale PV
Proven Technology Performance	5	5	4	2	3	4	5	3	5	5
Minimize Life-Cycle Costs	3	3	4	4	4	3	3	3	4	4
Energy/Resource Recovery	4	4	5	4	4	4	2	1	5	5
O&M Impacts	3	4	3	4	4	4	3	4	5	5
Environmental Impacts	3	3	4	5	5	5	3	3	5	4
Community & Stakeholder Impacts	4	4	5	5	5	4	3	3	5	5
Project Site Compatibility	5	5	4	4	4	4	5	3	2	2
Weighted Score	3.95	4.05	4.25	3.85	4.05	4.05	3.35	2.60	4.60	4.45
Ranking	5	4	3	6	4	4	7	8	1	2

CNG = compressed NG; O&M = Operations and Maintenance; PV = photovoltaics.

Section 1: Introduction

EWA has undertaken a Biosolids Energy and Emissions Plan (BEE Plan) which will be used to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed Process Master Plan. The BEE Plan has several goals:

1. Provide a comprehensive analysis of all project elements including biosolids treatment, gas use, energy generation, and waste heat;
2. Address capacity limitations in the solids handling process at the EWPCF;
3. Assess which alternative is likely to be the most cost effective and sustainable solution for EWA;
4. Move the EWPCF toward lower energy costs, rate stability, and greater overall sustainability.; and
5. Reduce greenhouse gas emissions (GHGs).

The purpose of TM 3 is to conduct a technology screening for alternative power production methods that could help EWA move toward their goal of greater energy independence. Alternatives evaluated in this TM do not consider potential energy reduction measures at EWPCF; the focus is placed on power production. This TM does not provide an alternatives analysis but provides insight into the methodology and rationale used to select alternatives which will move forward for further analysis in the SWEET model development.

1.1 TM 3 Purpose and Scope

This TM is preceded by TM 1 which addressed the baseline energy profiles and projections, established a mass balance for the solids handling system, and evaluated sludge flows and loads projections performed under the Process Master Plan. Screening and evaluation of solids processing technologies is described in TMs 1 and 2, including derivation of the biogas projections used in the alternatives evaluation presented in this TM.

TM 3 summarizes the methodology for screening and evaluating alternative power production technologies, the technologies evaluated, and how these alternatives were ranked to determine which would move forward in the SWEET analysis. While an emphasis was placed on those technologies that utilize the biogas generated from sludge digestion, additional alternatives such as solar and wind power were also investigated. Non-power-producing technologies, such as biogas upgrading, are included in the evaluation – recognizing that these alternatives help EWA realize its goals of economic and environmental benefits. Recommended technologies will be advanced for further analysis and will be combined with the solids handling and waste heat alternatives presented in TMs 2 and 5. Screening and ranking of technologies were performed in a workshop with EWA staff on August 16, 2017. Meeting minutes from this workshop have been provided as Attachment A.

1.2 Background Information

The EWA cogeneration system has four Caterpillar 3516 IC engine-generators installed in the Power Building; each engine-generator can generate a maximum of 750 kW. Currently, one IC engine at the EWPCF serves as a standby unit, with the other three IC engines available for cogeneration. The existing engines are capable of operating on either biogas, NG, or blended biogas and NG. NG is blended with air at the eclipse units to reduce the British thermal units (Btu) value to biogas values, it is then introduced to the biogas header feeding both the engines and the thermal biosolids dryer. This only occurs based on header pressure during times of high biogas demand. There is no biogas conditioning upstream of the engine-generators.

During peak electrical hours, the EWA operates generators to match the plant electrical demand and allow the plant to disconnect from the electrical grid, receiving compensation from the electrical utility for this arrangement (NG EMP). During these periods, a third engine is brought on line and operates on NG to increase engine-generator output.

EWA is pursuing modifications to its air permit to increase the permitted generating capacity of the plant. Because this effort is a work in progress, this TM reflects the current air permit and the screening process presents the relative comparisons of emissions. It is assumed that exhaust treatment is required to increase permit capacity, but the ability of each technology to meet air permitting requirements needs further verification as the permit process unfolds.

The current and future biogas projections are discussed in greater detail in TM 1. These projections assume the current high strength waste (HSW) quantities will be imported for codigestion and the future increase in biogas production is a result of the increased municipal sludge loadings only. A summary of the projections is shown in Table 1-1.

Table 1-1. Projected Biogas Production

	Current	2020	2030	2040
scfm	501	528	619	709
therms/year	1,581,000	1,666,000	1,951,000	2,235,000

[1] Projected biogas production is based on current wastewater and alternative fuels loadings. Potential for additional biogas from codigestion of additional alternative fuels is presented in TM 4.

scfm = standard cubic feet per minute

Section 2: Identification of Technologies for Alternative Power Production and Fatal Flaw Screening

The BC team worked with EWA staff to identify an initial list of alternative technologies that could contribute to increasing the on-site energy production powered by renewable fuels. The initial list includes the following:

- Continued use of the existing internal combustion engines
  - With gas conditioning
  - With gas conditioning and exhaust treatment
- Biogas upgrading
  - Pipeline injection
  - On-site vehicle fueling
- Microturbines
- Biosolids drying – direct use of biogas
- Energy storage (batteries only. HSW storage and biogas storage are included in TM 4)
- Fuel cells
- Large scale solar photovoltaics (PV)
- Small scale/rooftop solar photovoltaics
- Wind turbines
- Direct sale of biogas to Encina Power Station

These technologies are discussed in subsequent sections in further detail. The alternative power production technologies were first screened using four fatal flaw criteria that were developed in conjunction with EWA staff. The fatal flaw screening criteria include the following:

- **At least one successful North American installation of technology.** There must be at least one full-scale installation of the technology at a wastewater treatment plant (WWTP) in North America.
- **At least one successful installation and operation in a facility of similar size.** The technology should be sufficiently developed that it is applicable at a facility of comparable size to EWPCF to ensure compatibility.
- **Available space.** The technology must be accommodated within the limited available footprint at EWPCF.
- **Compatibility with plant site and any existing equipment.** The technology must be capable of being integrated into the existing treatment plant infrastructure.

For an alternative to be considered for the ranking process, the alternative must pass all four fatal flaw criteria.

2.1 Internal Combustion Engine-Generators

This alternative assumes biogas is used as the primary fuel to the existing IC engine-generators to cogenerate heat and electricity. Current operation of the four 750 kW IC engines was discussed in Section 1.2. As mentioned, EWA is pursuing an alternative air emissions strategy via an air permit modification to increase use of available generating capacity. A revised permit strategy may require the addition of gas conditioning, exhaust treatment, or a combination of these possibilities and will be discussed in TM 4. Additionally, instead of pursuing an alternative air emissions strategy, microturbines (discussed in Section 2.3) may be paired with the IC engines to increase the electrical generating capacity of EWPCF. In this case, exhaust treatment would not be required, but upstream gas conditioning would be needed to meet inlet requirements of the microturbines. Figure 2-1 shows the existing engines located in the power generation building.

Figure 2-1. Existing 750 kW Caterpillar engines at EWPCF

In addition to the current IC engines operating at 750 kW electrical output, a second variation was considered for the evaluation in which engines would return to rich burn operation to provide 900 kW electrical output. EWPCF's original permit was for 0.5 grams of NOx per brake horsepower-hour and to achieve this level of nitrogen oxide (NOx) emissions, the original 900 kW engine was derated to 750 kW and a 750 kW generator was installed as part of the package. BC reviewed this alternative and does not recommend this alternative be carried forward since 1) the modified November 2017 air permit allows EWA to run engines at nearly plant demand; and 2) changing the engine generator output would likely require a permit modification.

With several of the IC engines' sub alternatives, in conjunction with microturbine and solar alternatives that will be discussed in Sections 2.3, 2.7 and 2.8, EWPCF may generate more power than is required to operate the plant. If power production exceeds demand, EWPCF may be able to earn revenue through exporting power to the grid. Net metering power to the grid is discussed further in Section 2.11.

IC engines have been used at EWPCF since 1983 to generate electrical power to reduce electricity costs for EWA. The engines also provide a source of emergency standby power to meet EWA's National Pollution Discharge Elimination System permit. Since the plant already operates four 750 kW IC engines, this alternative passes all fatal flaw criteria; i.e., the engines successfully generate power, they are already located at the plant, and are compatible on the existing site. The IC engines alternative passes the fatal flaw filter and will be carried forward in the evaluation screening.

2.2 Biogas Upgrading and Beneficial Use

Biogas upgrading produces biomethane, a renewable NG substitute that can also be used as vehicle fuel as compressed NG (CNG). Similar to conventional gas treatment systems that remove contaminants to improve engine performance, biogas upgrading first involves gas conditioning to remove moisture, hydrogen sulfide, and siloxanes from the raw biogas and gas compression. After contaminants are removed from the gas, the gas goes through a separation process to separate methane from carbon dioxide. The resulting product is a methane-rich process gas (biomethane or renewable NG) and a methane-lean tail gas consisting primarily of carbon dioxide with up to 25 percent of the total biogas methane depending on the selected separation system. Tail gas is typically wasted using a flare or thermal oxidizers and typically requires a supplemental NG feed to help the tail gas combust.

There are several biogas separation technologies available including membranes, pressure swing adsorption, and water solvents. Figure 2-2 shows an example biogas upgrading system provided by Unison Solutions that utilizes membrane separation. Other typical biogas separation technology manufacturers include Air Liquide, Guild, and Greenlane. These technologies will be described in greater detail in TM 4.

Figure 2-2. Biogas upgrading system at San Mateo WWTP (CA) using Unison's BioCNG system

Includes hydrogen sulfide removal, moisture removal, compression, siloxane removal, and membrane separation.

Upgraded biogas is either routed to a pipeline injection system or to on-site storage and dispensing of vehicle fuel, both described below in Table 2-1. Upgraded biogas can also be sent to a tube trailer to transport to an off-site fueling facility; in this case, the upgraded biogas must meet the on-site vehicle fueling criteria but requires less on-site storage. Southern California Gas Rule No. 30 (Transportation of Customer-owned Gas) provides requirements for gas to be injected into the utility pipeline; this rule was used to derive the values in Table 2-1. Vehicle fueling specifications are based on generally acceptable values for CNG engines, such as Cummins-Westport. Vehicle fuel standards are generally less stringent than California's NG pipeline standards.

Table 2-1. Comparison of Biogas Upgrading Pipeline Injection and Vehicle Fuel

	Vehicle Fueling	Pipeline Injection (Rule No. 30)
Methane, percent by volume, min	95	99
Carbon dioxide, percent by volume, max	3.0	3.0
Oxygen, percent by volume, max	0.1	0.2
Sum of carbon dioxide, nitrogen, oxygen percent by volume, max	5.0	4.0
Higher heating value, Btu/scf, min	960	990
Water, lb / million scf, max	7	7
Hydrogen sulfide, ppmv, max	4	4
Mercaptan sulfur, ppmv, max		5
Total sulfur, ppmv, max	16	12.6
Total measurable siloxanes, ppbv, max	100	
Total ammonia, ppmv, max	10	

Table 2-1. Comparison of Biogas Upgrading Pipeline Injection and Vehicle Fuel

	Vehicle Fueling	Pipeline Injection (Rule No. 30)
Other volatile organic compounds, ppbv, max	100	
Free of dust and gum, filtration to, micron, max	0.3	
Discharge Pressure, psig	4500	Depends on injection location
Example Facilities	Janesville, WI San Mateo, CA	Point Loma, CA

lb = pounds; ppbv = parts per billion by volume; ppmv = parts per million by volume; psig = pounds per square inch gage; scf = standard cubic feet.

Both biogas upgrading alternatives are eligible for incentives under by the Low Carbon Fuel Standard (LCFS) and Renewable Fuel Standard (RFS2). The LCFS is a state-administered program with a goal to lower greenhouse gas emissions from petroleum-based transportation fuels by requiring producers of petroleum-based fuels to reduce the carbon intensity (CI) of their products by either developing their own low-carbon fuel products or purchasing LCFS credits from other companies or producers that develop and sell low-carbon alternative fuels. Credits are a tradable environmental commodity with a monetary value and are typically managed by a third-party broker. Similarly, the RFS2 is an EPA program that requires transportation fuel to contain a minimum volume of renewable fuels. Renewable fuel sources include biomass-based diesel, cellulosic biofuel, advanced biofuel, and total renewable fuel. The RFS2 mandates that fuel refiners obtain renewable fuel credits called Renewable Identification Numbers (RINs) to meet a minimum percentage of renewable fuel production.

Sending biomethane to the existing San Diego Gas & Electric (SDG&E) pipeline would allow for more flexibility with operations by allowing biogas to be processed as it is produced rather than storing it, and requires less space at the plant than vehicle fueling. Injected biomethane can be sold to any party with a physical connection to California's NG grid. The sale is typically managed through a third-party broker. This alternative is similar to the Point Loma WWTP, a 175 million gallons per day (mgd) plant, which currently produces biomethane and injects it to the SDG&E NG pipeline through a service-provided contract with BioFuels Energy, LLC.

On-site vehicle fueling requires additional equipment for compression, storage, and dispensing of CNG. High pressure CNG compressors are required to boost the pressure of the gas up to approximately 4,500 pounds per square inch gage (psig). On-site fueling requires EWA to find a committed, local partner who can use the renewable CNG fuel. The amount of fuel produced requires an agreement with a large vehicle fleet, such as buses or solid waste collections. Identification of a partner is critical to this option moving forward. Figure 2-3 shows an installation photograph of these high pressure CNG compressors. Figure 2-4 shows high pressure CNG storage vessels and a typical fuel dispenser.

Figure 2-3. Example of ANGI high pressure compressors

Figure 2-4. Example of ANGI vehicle fueling equipment, including high pressure storage and fuel dispenser

As an alternative to on-site vehicle fueling, vehicle fuel-quality biomethane may be transported to an off-site fueling facility via a tube trailer. This option eliminates the need for on-site storage but still requires a committed local partner. Transporting biomethane in tube trailers was discussed in a meeting with waste haulers that operate near EWPCF. These haulers were not interested in receiving tube trailers and preferred obtaining NG directly from the pipeline. Additionally, hauling costs for the significant quantity of biomethane that can be produced at EWPCF are likely to be prohibitive. For these reasons, hauling biomethane in tube trailers is not a viable option.

Neighbors at the Point Loma WWTP currently upgrade their biogas to biomethane or renewable pipeline NG. One difference to note is that Point Loma staff do not operate or maintain the gas upgrading equipment—the gas is sold to BioFuels Energy, LLC. This private entity operates the biomethane gas purification and injects the upgraded biogas into the pipeline for use. While Point Loma WWTP is under a service type contract for sale of their biogas, the project still demonstrates that a full-scale project is feasible. Biogas upgrading equipment could fit near the existing digesters or where the old Maintenance Building is located. The biogas upgrading alternative passes the fatal flaw filter and will be carried forward in the evaluation screening.

2.3 Microturbines

Microturbines are small combustion turbines that cogenerate heat and electricity. Packaged microturbine units are available in capacities ranging from 65 to 333 kW per unit. Microturbines are a compact, easily scalable, low-emission technology for utilizing biogas. Microturbines are extremely sensitive to siloxanes and require gas conditioning to remove sulfides, moisture, and siloxanes and require compression up to 80 psig. One of the disadvantages, in comparison to IC engines, is a lower electrical efficiency; microturbines have an efficiency of 30 to 32 percent while IC engines see an efficiency of 35 to 40 percent. The two main microturbine manufacturers are Capstone and FlexEnergy, both companies with factories in the United States. Figure 2-5 shows a microturbine package installation with capability of producing 1,000 kW. Microturbines are capable of operating on the tail gas of a membrane separation biogas upgrading system where energy content is as low as 300 British thermal units per cubic foot to replace a flare or thermal oxidizer.

Figure 2-5. Capstone C1000, 1000 kW microturbine package with integrated exhaust manifold

Microturbines would not replace the existing IC engines, but would be added to increase power generation. They would run continuously and simultaneously with the existing engines and would maximize biogas utilization for combined heat and power. Because microturbines produce low emissions in comparison to an IC engine, coupling them with IC engines is a viable alternative to pursuing permit modifications and associated exhaust treatment for the IC engines.

Several treatment plants in the United States operate Capstone microturbines including Janesville, Wisconsin; Sheboygan, Wisconsin; Durango, Colorado; Persigo, Colorado; and Santa Margarita, California—all of which have reported successful operation. Microturbines would be used at EWPCF to supplement power production in conjunction with existing IC engines and multiple units could be installed. Microturbines have a relatively small footprint and would fit onto the site easily. However, because microturbines require gas treatment, the conditioning system footprint was also considered when determining space availability. The microturbine alternative passes the fatal flaw filter and will be carried forward in the evaluation screening.

2.4 Direct Use of Biogas in Drying

Biogas can be blended with NG and used to fuel a sludge dryer. EWA currently operates an Andritz DDS40 sludge dryer, which, according to current equipment specifications, can utilize a maximum 82 percent biogas and 18 percent NG blend. However, Andritz has stated that the DDS40 has been fueled with 100 percent biogas at certain facilities and Andritz is under contract to perform biogas optimization for the dryer at EWPCF. EWA currently uses excess biogas in typical dryer operations. Dryer fuel requirements are dependent on sludge flow; greater flows signal a greater capacity to utilize biogas. Under the current operating strategy, EWA's biogas use is lower than the maximum allowed by Andritz for biogas blending; therefore, the dryer has capacity to consume additional biogas. Biogas utilization can be further increased if Andritz determines a greater biogas blend may be used. If a second dryer is installed to accommodate increasing sludge flows, the dryer system would have even more capacity to consume excess biogas.

Since the plant already uses biogas in the solids dryer and has capacity to consume additional biogas for biogas, this alternative passes all fatal flaw criteria and will be carried forward in evaluation screening.

2.5 Energy Storage (Batteries)

Without energy storage, power that is generated at a WWTP must be utilized as it is produced. With energy storage, a WWTP can store excess power during low demand periods and use the stored power to reduce peak electricity demand, also known as energy arbitrage. Combining on-site power generation with energy storage can reduce electricity bills by decreasing both overall energy consumption and non-coincident demand charges. Battery storage is typically provided with microgrid controllers that manage the storage and deployment of power.

Lithium-ion batteries are the most common energy storage technology and have only recently been applied at a WWTP. Lithium-ion batteries are rechargeable and operate through the movement of lithium ions between negative and positive electrodes, however, there are energy losses as the battery charges and discharges. In 2016, Napa Sanitation District partnered with Tesla to install five batteries that can capture 1 megawatt (MW) and store 2 MW hours (MWh) of electricity. The Tesla batteries at Napa Sanitation District are shown in Figure 2-6. Other manufacturers, including LG, Mercedes, and Nissan, are developing their own large capacity batteries.

Figure 2-6. Napa Sanitation's Tesla Batteries

Note: Five units can store 1 MW/2 MWh of electricity.

Napa Sanitation District implemented a battery storage project in partnership with Pacific Gas & Electric and Tesla in 2016. The plant installed five Tesla batteries to capture and store 1 MW/2 MWh of electricity. Tesla has also partnered with Southern California Edison to install an 80 MWh project at the Mira Loma substation in January 2017. Additionally, Inland Empire Utilities Agency is installing batteries at several facilities in Southern California in conjunction with Advanced Microgrid Solutions. The energy storage via batteries alternative passes the fatal flaw filter and will be carried forward in the evaluation screening.

2.6 Fuel Cells

Fuel cells produce electrical power directly through an electrochemical reaction that uses hydrogen and oxygen. For application at EWA, a fuel cell would use methane as a hydrogen fuel source and air as an oxygen source. To utilize biogas in the fuel cell, the biogas would require upstream gas conditioning to remove sulfur, siloxanes, metals, and moisture. Gas quality requirements for fuel cells are higher than for IC engines, since small amounts of contaminants can ruin fuel cell stacks.

Fuel cells are not charged prior to use like batteries described in Section 2.5 and are instead fed hydrogen and oxygen continuously to provide a constant power output. The reaction does not involve combustion, has no moving parts, and has very low emissions of criteria pollutants. Figure 2-7 demonstrates the basics of how a fuel cell works—hydrogen is fed to the anode and oxygen is fed at the cathode. As hydrogen moves from the anode to the cathode through an electrolyte, electricity is created. Molten carbonate fuel cells are the most common types of fuel cells and have an electrical efficiency of roughly 45 percent.

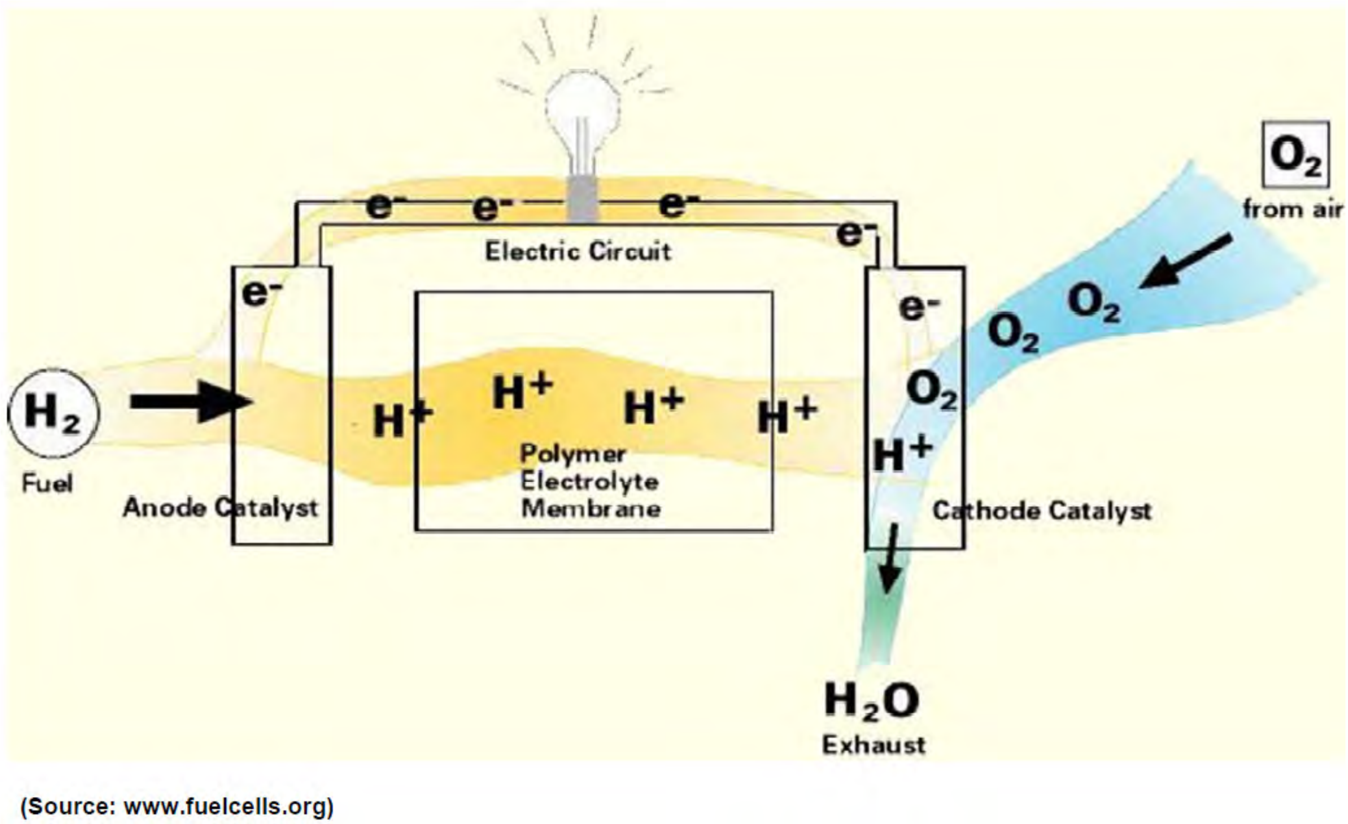

Figure 2-7. Fuel cell electricity generation process diagram

While fuel cells are an established technology with multiple manufacturers and thousands of installations in the world, many treatment plants have reported problems with operation on biogas with numerous fuel cells abandoned. Fuel cells were a popular option for WWTPs in the 2000s due to direct subsidies; however, these subsidies have ended, making this alternative less economically attractive.

Fuel cells do not pass the fatal flaw filter on technology maturity and successful operation criteria. While fuel cell technology reportedly has air emissions benefits and high electrical efficiency, numerous treatment plants have reported poor fuel cell performance and no longer operate their units (e.g., the San Jose-Santa Clara Regional Wastewater Facility, Inland Empire, King County, and New York City). Additionally, the grants and subsidies that once made fuel cells financially attractive are no longer in place and would mean high life-cycle costs. The fuel cell alternative fails the fatal flaw filter on technology maturity and successful operation and will not be carried forward in the evaluation screening.

2.7 Large-Scale Photovoltaics

For large-scale solar projects at wastewater treatment plants, the majority are installed by third party developers who have access to federal tax credits, which are limited to private entities. Power is typically sold back to the utility at a fixed rate with inflation escalation. The third party typically pays for capital costs and operations and maintenance (O&M) of the system since the plant will continue to pay for the cost of power. This third-party arrangement is called a power purchase agreement. EWA has the option to use a power purchase agreement, or own its own system.

EWA has identified available space for a large-scale solar project on the southeast parcel of the plant. The estimated available footprint is 13 acres, unless the plant reserves this space for future processes. Additionally, Figure 2-8 demonstrates a high amount of solar resource near the EWPCF.

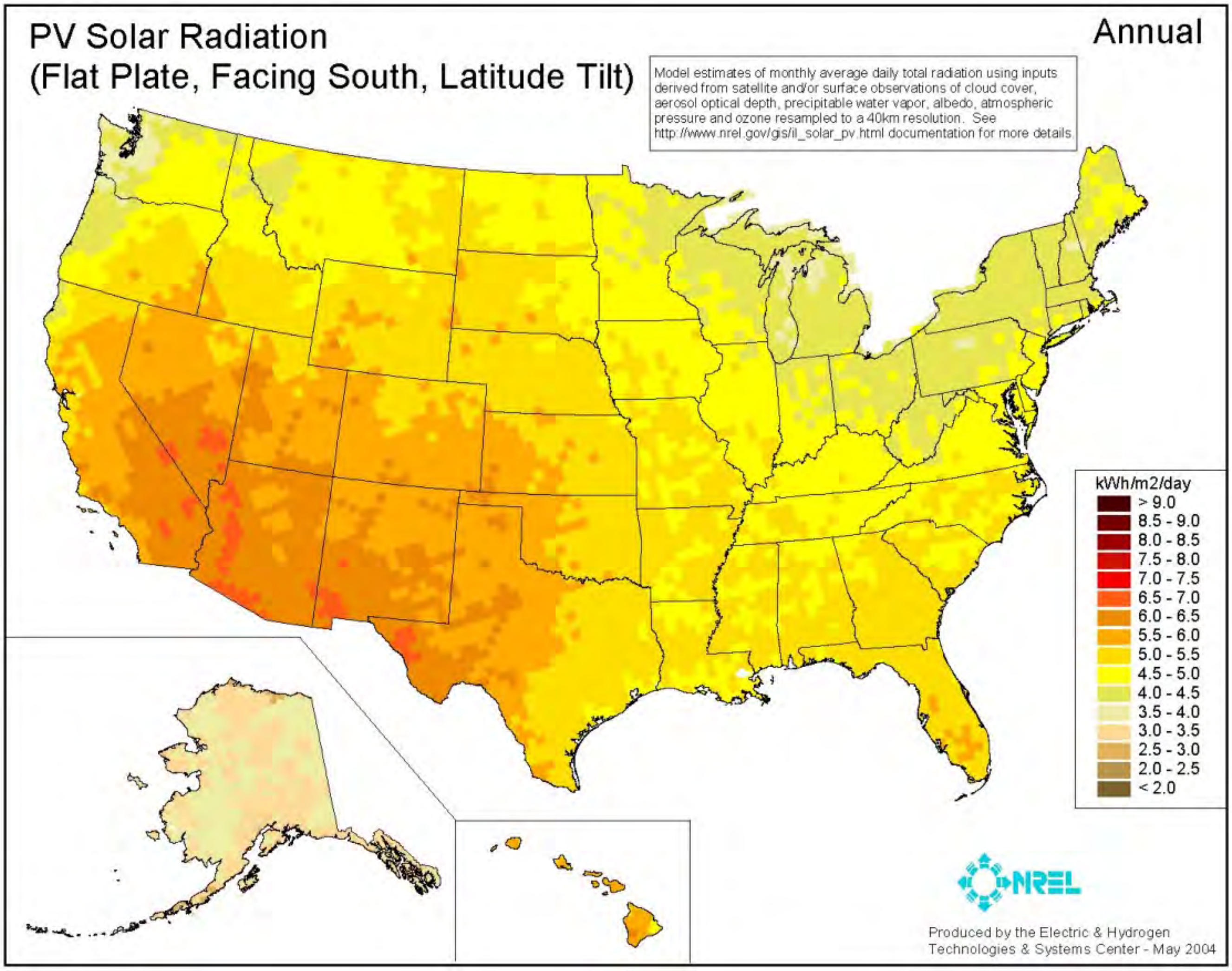

Figure 2-8. PV solar radiation intensity

A major disadvantage of PV systems is that solar power is intermittent as sunlight quantity and intensity vary greatly throughout a day. The best solar conditions occur in the middle of the day, and the power demands of WWTPs do not follow the same diurnal cycle as the rest of the electrical grid. Coupling energy storage with PV systems can increase the benefits of solar power by allowing power to be provided as needed, not as produced. This is especially true for facilities like EWA that would like to maximize renewable power consumption without exporting power to the grid during peak solar production periods.

As mentioned previously, solar PV is a mature technology with numerous successful operations. Large-scale solar PV uses the same technology as rooftop solar panels on a larger scale (greater than 1 MW). Large-scale solar PV would require approximately 5 acres of panels and could be located on the south parcel of the plant. The large-scale solar PV alternative passes the fatal flaw filter and will be carried forward in the evaluation screening.

2.8 Small-Scale Photovoltaics

Small-scale PV systems have less than 1 MW of electricity generating capacity and can range in size from a single panel used to power an instrument to a moderately sized solar array installed across a few acres of land. Smaller systems are typically more expensive per unit of power produced than large-scale systems but panels can be located using whatever space is available, including rooftops. Small-scale PV systems at EWPCF could be installed on building rooftops, such as the Solids Dryer and Power buildings. The covered aerations basins or the equalization ponds present available areas for PV installation.

Figure 2-9. Union Sanitary District Irvington Pump Station PV Project included 460 kW of installed solar PV in an emergency overflow basin

There are thousands of small-scale solar installations in North America on residential and commercial buildings, as well as at wastewater facilities such as USD Irvington Pump Station in Northern California. The small-scale solar PV alternative passes the fatal flaw filter and will be carried forward in the evaluation screening.

2.9 Wind Turbines

Wind turbines can be purchased in a variety of sizes; utility-scale turbines are available in 100 kW to several MW units. Unit sizing is dependent on the quantity and quality of the available wind resources and the desired power output. Smaller turbines can produce power with slower wind speeds whereas larger turbines require greater wind speeds to turn the blades and generate electricity. For example, a 100-kW turbine can produce 3.7 kW with a wind speed of 9 miles per hour, and power output increases with wind speed. Turbine height, noise limits, impacts on bird species, and aesthetics must also be considered in turbine selection and sizing.

While wind turbine technology is well established and has many successful installations around the world, it is not geographically workable with EWA's site. Wind resources are low near the coastline and would not provide a large return on investment. A wind resource map of California is provided in Figure 2-10. In addition, a large wind turbine would not meet community requirements for aesthetics on the coastline and is, therefore, not compatible with the current site layout. The wind turbine alternative fails the fatal flaw filter on available space and will not be carried forward in the evaluation screening.

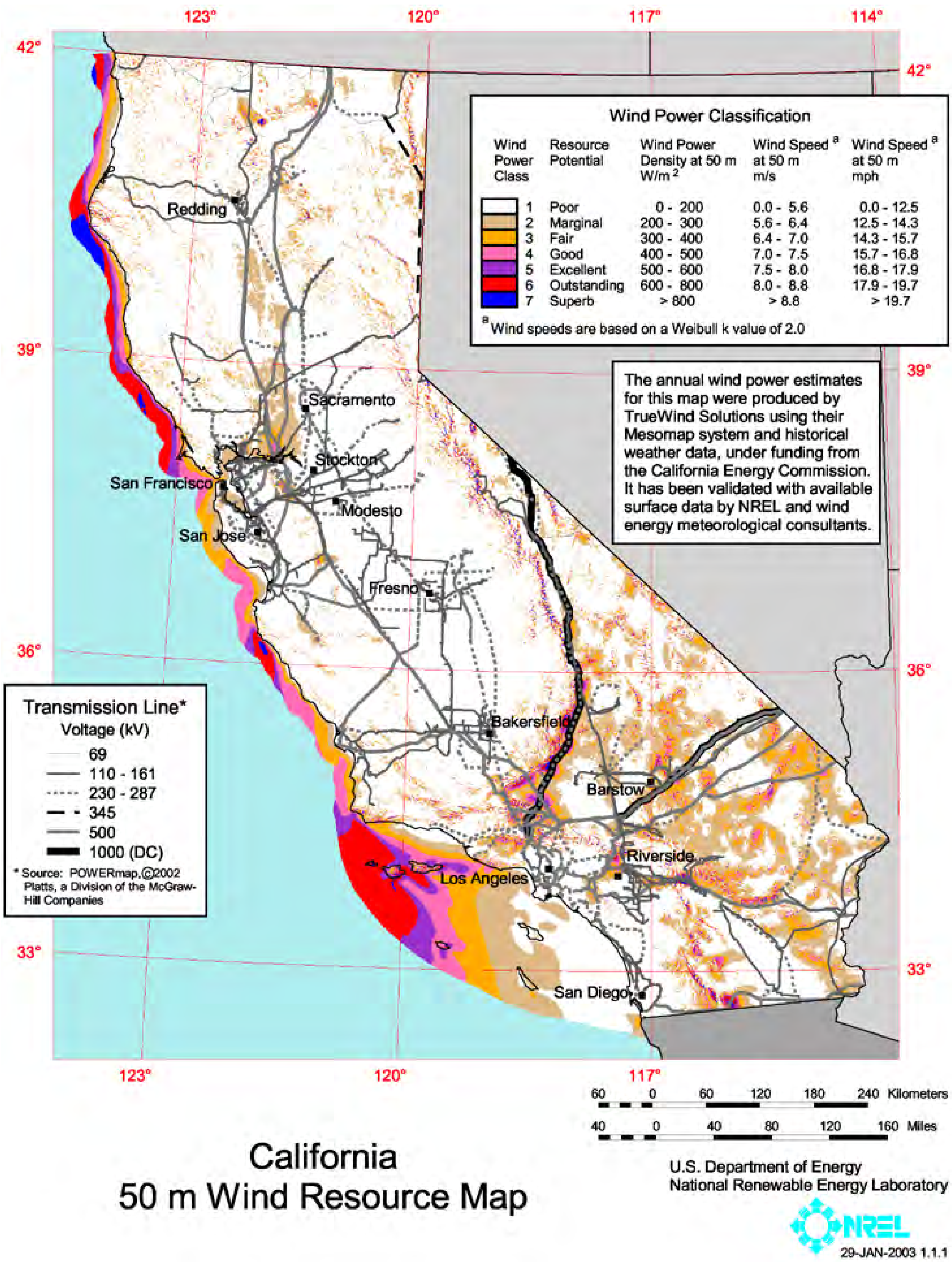

Figure 2-10. Wind Resource Map of California

2.10 Direct Sale to Adjacent Power Plant

This alternative is a direct sale of biogas to the nearby Encina Power Station and would include a conveyance pipeline and gas treatment. Encina Power Station is a large NG and oil-fueled electricity generating plant located a couple of miles away from the EWPCF. Cleanup requirements will depend on the fuel agreement and power plant. Untreated biogas can be used in boilers and duct burners; however, higher levels of conditioning or separation would be required for fueling the generation equipment. Example treatment plants that have sold, or are currently selling their biogas to power plants include Sacramento Regional Wastewater Treatment Plant and Hyperion Water Reclamation Plant.

Ultimately, selling biogas to a nearby power plant gets EWA the lowest value for their biogas. RINs and LCFS credits do not apply to biogas sold for power production because these credits only apply to biogas used for vehicle fuel. After reviewing EWPCF's NG bills, the market value of NG is much lower than potential value from generating electricity or producing vehicle fuel to make this option economically feasible and will not be carried forward.

2.11 Net Energy Metering

A net energy metering (NEM) agreement with SDG&E can be applied to any alternative that generates electricity from a renewable fuel (e.g., biogas-fueled IC engines, biogas-fueled microturbines, and solar PV). NEM would track how much grid electricity is consumed by EWPCF and how much excess electricity is renewably generated; EWPCF would only pay for the net electricity consumption. The benefits of NEM can be maximized if most power generation occurs during high demand periods and most power consumption occurs during low demand periods. NEM eliminates costly standby charges, which is a major benefit. NEM requires interconnection to the grid, and generated power would not be used directly by EWPCF.

NEM is considered an alternative that can be combined with power generation alternatives in the SWEET analysis; however, NEM is not included in the Fatal Flaw Screening and Technology Ranking that are presented in this TM. Table 2-2 lists likely electrical upgrades that would need to be implemented if going to net metering triggers the requirements for a new Rule 21 interconnection application. Attachment B includes the SDG&E Distribution Interconnection Handbook and potential electrical upgrades specific to EWPCF's system that would be required for a Rule 21 interconnection agreement. The biggest issue, both technically and from a cost perspective, appears to be that SDG&E would require real-time metering of the net generator output completely separate from the metering at the point of interconnection. Based on the plant's record drawings, the facility was not originally set up for this. The reasoning typically given for this SDG&E requirement is that the utility is managing a large, dynamic system and they need to know how much active generation output of each type they have connected to each segment of their system to manage it. The 1 MW threshold is to prevent this from being too burdensome to small (typically solar) generators.

Table 2-2. SDG&E Rule 21 Interconnection Electrical Upgrades		
Requirement	**Reference**	**Implementation Level of Effort**
Replace Main Utility Meters with NEM Capable Meters	SDG&E Interconnection Handbook §2.1	Easy – utility swaps these into the existing meter sockets.
Add SDG&E Metering to measure "net generator output" and "provide real-time kW and kVAR transmitted to SDG&E grid ops." [Required for generating facilities >1MW. This is not metering at the point(s) of utility connection – this is the actual net output of the generation system, regardless of plant load.]	SDG&E Interconnection Handbook §2.1 and §2.2 Figure 1	Difficult - the way the plant is currently set up, this would require cutting in new utility metering at each generator (which requires physical modification, new conduits/cables, and new SCE metering cabinets).
Provide service to SCE's telemetering equipment (high-speed data line and 120VAC UPC circuit) at location of meters for the generators.	SDG&E Interconnection Handbook §2.6	Moderate – requires routing of conduit/cables to generator area, making physical space available for SCE's telemetering equipment.
Add visible disconnect switches for lock-out / tag-out of generation facility. [SDG&E may allow racking out the existing breakers to meet this requirement, but this is evaluated on a case by case basis.]	SDG&E Interconnection Handbook §3.2	Difficult if required – requires physical modification of conduits/ductbanks, re-routing of cables, and physical location/mounting of equipment.
Reconfigure generator controls system for continuous paralleling and export mode as opposed to load following or islanding mode. Change generator control system to regulate power factor (not voltage) when connected to SCE's system (if not already implemented).	SDG&E Interconnection Handbook §3.3	Moderate - Likely to be possible with the existing generator control system, but will require on-site time for implementation and testing by the generator control system supplier.
Modify existing main switchgear protective relays to allow sensing of ground faults on utility system (so that plant generators don't feed into it).	SDG&E Interconnection Handbook §3.3 & §3.6	Moderate - Requires main switchgear shutdown (of one side at a time) for minor internal physical modification of existing switchgear. Also reconfiguration and retesting of existing relays after new settings are approved by SDG&E.
Witnessed "Pre-parallel testing" required for SCE sign-offs.	SDG&E Interconnection Handbook §6.3	Thorough on-site testing of switchgear protective relays, generator control system, and metering interface. Usually multiple days with several different suppliers, an independent testing firm, and the utility's representative on site.
SCE System Upgrades (transfer trip, reclose blocking, etc.) – items that SCE will have to upgrade on their side of the system. [Dependent on the overall conditions of the SCE circuit being connected to and other customers - cannot be known or obtained from SCE until an application is submitted and SCE performs an engineering study.]	SDG&E Interconnection Handbook §3.6	Little activity on the EWA side – this is more of a project cost issue.

2.12 Fatal Flaw Conclusions

The results of the fatal flaw screening evaluation performed in this section are presented in Table 2-. Alternatives that passed the fatal flaw filter will each be evaluated and scored in Section 3 to determine which alternatives will be analyzed using BC's SWEET tool.

Table 2-3. Power Production Technology Screening: Fatal Flaw Evaluation				
	Technology Maturity	Successful Operation	Available Space	Compatibility
Internal Combustion Engines	Pass	Pass	Pass	Pass
Digester Upgrading: Pipeline Injection	Pass	Pass	Pass	Pass
Digester Upgrading: Vehicle Fueling (CNG)	Pass	Pass	Pass	Pass
Microturbines	Pass	Pass	Pass	Pass
Biosolids Drying - Direct Use of Biogas	Pass	Pass	Pass	Pass
Energy Storage	Pass	Pass	Pass	Pass
Fuel Cells	Fail	Fail	Pass	Pass
Wind Turbines	Pass	Pass	Fail	Fail
Small Scale/Rooftop Solar Photovoltaics	Pass	Pass	Pass	Pass
Large Scale Solar Photovoltaics	Pass	Pass	Pass	Pass
Direct Sale to Adjacent Power Plant	Pass	Pass	Pass	Fail

Ultimately, the IC engines, biogas upgrading, microturbines, biosolids drying, energy storage, and solar PV alternatives passed the fatal flaw filter and will be reviewed further in the technology screening evaluation (presented in Section 3).

Section 3: Ranking of Screened Technologies

This section describes the results of applying the evaluation criteria described in Section 2 to further screen and rank the technologies that passed the fatal flaw filter.

3.1 Introduction

Technologies that passed the fatal flaw filter were evaluated using a weighted scoring matrix. The final scores and weights were fixed in Workshop 2 with EWA staff. In this analysis, a weighted average score of 3 or less led a technology to be eliminated from further consideration. The rationale behind the scoring for each technology area is described in this section.

3.2 Criteria Descriptions and Weightings

Alternatives that passed the fatal flaw filter were further evaluated and ranked based on both economic and non-economic screening criteria. The BC team worked with EWA staff to develop a series of evaluation criteria that reflect the project goals, EWA's values, and EWA's general operational practices. Criteria weights were assigned in Workshop 2 with EWA staff. Criteria and weightings are presented in Table 3-1.

Table 3-1. Criteria and Weight for Technology Screening			
Criterion	Description	Scoring Description	Weight
Proven Technology Performance	Proven and reliable technology with same configuration intended at Encina. Long successful operating track record.	Low score indicates no successful large scale operating installations in North America or Europe, no successful demonstration scale installations in North America or Europe, and unknown safety or reliability record. High score indicates more than one successful operating installation in North America or Europe, more than one operating installation at a WWTP of at least 40 mgd in North America or Europe, track record duration > 5 years, and vendors in western USA.	20%
Minimize Life-Cycle Costs	Qualitative metric of program cost. Capital and O&M costs based on existing EWA data or similar experience at other WWTPs. Potential revenues from sales.	Low score indicates high capital cost to build onsite facilities, high O&M costs, and low energy recovery efficiency. High score indicates low capital cost to build onsite facilities, low O&M costs, and potential revenue.	10%
Energy/Resource Recovery	Recovery of renewable energy.	Low score indicates high energy requirement for onsite technology, technology does not recover, and low efficiency recovery of renewable energy. High score indicates a higher electrical efficiency.	25%
O&M Impacts	Impacts to existing plant O&M staff levels. Complexity of new technology O&M and control systems. Reliability of new technology (potential downtime). Minimal impacts to plant safety.	Low score indicates more O&M time required, complex mechanical and control systems required compared with existing plant facilities, potential equipment downtime, and newer hazards. High score indicates reduction in O&M staff time required, new technology is simple to operate and maintain, reliable with minimal downtime, and no new hazards.	10%
Environmental Impacts	Impacts to carbon footprint and air permitting.	Low score indicates high carbon footprint for technology, and new permitting for environmental regulatory requirements. High score indicates low carbon footprint for technology, reduced pollutant emissions, no additional permitting for environmental regulatory requirements.	15%
Community & Stakeholder Impacts	Minimize nuisance impacts such as dust, odors, vectors, aesthetics, noise and traffic. Assess impacts to partner agency issues/values as well as local planning codes and requirements.	Low score indicates nuisance factors for on-site technology are difficult to mitigate. High score indicates nuisance factors can be mitigated at plant site.	10%
Project Site Compatibility	Assess compatibility of technology with available plant footprint. Incorporation into existing treatment process.	Low score indicates lack of site space for new facilities, requires abandonment of existing facilities, and difficult integration with existing plant. High score indicates available footprint for new facilities and maintains space for future facilities, ease of integration with existing processes and facilities.	10%

3.3 Results and Discussion

Table 3-2 shows the scoring results for the alternative power production technologies that passed the fatal flaw filter. Among these, small-scale rooftop PV, IC engines with gas conditioning, IC engines with selective catalytic reduction (SCR), and biogas upgrading to vehicle fuel scored the highest. Rationale behind the scoring for each technology area is described below.

Table 3-2. Alternatives Scoring Evaluation

	IC Engines - Status Quo	IC Engines - with Gas Conditioning	IC Engines - with Exhaust Treatment	Biogas Upgrading: Pipeline Injection	Biogas Upgrading: Vehicle Fueling (CNG)	Microturbines	Biosolids Drying	Energy Storage (Batteries)	Small-Scale Rooftop PV	Large-Scale PV
Proven Technology Performance	5	5	4	2	3	4	5	3	5	5
Minimize Life-Cycle Costs	3	3	4	4	4	3	3	3	4	4
Energy/Resource Recovery	4	4	5	4	4	4	2	1	5	5
O&M Impacts	3	4	3	4	4	4	3	4	5	5
Environmental Impacts	3	3	4	5	5	5	3	3	5	4
Community & Stakeholder Impacts	4	4	5	5	5	4	3	3	5	5
Project Site Compatibility	5	5	4	4	4	4	5	3	2	2
Weighted Score	3.95	4.05	4.25	3.85	4.05	4.05	3.35	2.60	4.60	4.45

3.3.1 Internal Combustion Engines

IC engines received the highest score for proven technology performance and project site compatibility since they are already in operation at the plant. Gas conditioning of biogas is a common practice for many treatment plants and does not require a significant footprint. In Workshop 3, plant staff agreed that gas conditioning equipment could be located on the empty space near the digesters and existing gas blowers. Exhaust treatment, particularly SCR, is proven on natural-gas-fueled engines, but has only recently been required for biogas facilities. The addition of SCR to biogas engines is driven by air permit standards in the state's most restrictive air districts, such as the South Coast and Bay Area. Robust biogas conditioning is required to protect the SCR catalyst. Few WWTPs operate engines with SCR; however, this technology is deemed feasible and "best available" in several districts. Orange County Sanitation District recently added SCR to their central generation facility to meet permit requirements. Figure 3-1 shows a site layout for potential implementation of gas conditioning and SCR gas treatment.

Figure 3-1. Site layout for IC engines with gas treatment technologies

Adding exhaust treatment to eliminate the permit restriction, thus allowing the plant to run more engines, would increase energy recovery and lower annual electricity costs. EWA staff are familiar with IC engines; i.e., there is no added complexity for this alternative. Adding gas conditioning reduces O&M effort on the engines, but introduces O&M required for the conditioning system. Exhaust treatment such as an oxidation catalyst and/or SCR will add a layer of complexity, especially for handling materials such as urea reactant and O&M and reporting for the continuous emission monitoring system.

Engines produce particulate matter, carbon monoxide (CO), sulfur oxide, and NOx emissions without exhaust treatment. With exhaust treatment, CO and NOx emissions are reduced and have less of an environmental impact.

3.3.2 Biogas Upgrading

Biogas upgrading is still considered an emerging technology and has fewer large-scale installations and less established equipment manufacturers. There are more installations of on-site vehicle fueling in California that have been in successful operation in comparison to pipeline injection; therefore, vehicle fueling scored a 3 and pipeline injection scored a 2. Example projects for pipeline injection are limited to California projects due to more stringent standards compared to other states.

Biogas upgrading alternatives can bring in potential revenue from LCFS and RINs credits generated for producing renewable fuel, currently valued between $1 and $2 per diesel equivalent produced (1440 cubic feet of biogas produces approximately 5 diesel gallon equivalents of fuel) in addition to the value of the fuel itself. However, they have a relatively high capital cost, thus, lowering the life-cycle cost score to a 4.

Generally speaking, the electricity grid is more renewable than the NG grid in California; therefore, decreasing the amount of purchased NG has a greater environmental benefit compared to reducing purchased electricity. However, depending on how much NG is purchased for running cogeneration engines or running a boiler as part of an overall biogas upgrading operation, this alternative may end up being more equivalent to the other options.

Figure 3-2 shows where the biogas upgrading for pipeline injection could be located at the plant and Figure 3-3 shows the alternative with on-site vehicle fueling.

Figure 3-2. Potential siting of biogas upgrading equipment at EWPCF

Figure 3-3. Potential siting of biogas upgrading and on-site vehicle fueling equipment at EWPCF

3.3.3 Microturbines

With proper biogas treatment, microturbines are a proven combined heat and power technology that is utilized at several treatment plants. While not as common as IC engines, microturbines are still a proven technology and more treatment plants, such as San Francisco Southeast Plant and Roseville Pleasant Grove WWTP, will be installing them. In addition, microturbines have very low emissions, are California Air Resources Board-certified and easy to permit; therefore, they have favorable environmental impacts.

Microturbines have a slightly lower capital cost than IC engines, similar O&M costs, but 20 to 25 percent less electrical energy recovery than IC engines; therefore, microturbines do not offset as much electrical costs. Life-cycle costs are similar to that of an engine; consequently, microturbines received a 3 in life-cycle costs.

Microturbines are packaged in a modular enclosure and can be easily removed from the system for routine maintenance. By installing multiple smaller capacity units, maintenance can be performed simultaneously to minimize downtime. Microturbines have few moving parts and have demonstrated high reliability when installed with proper gas treatment.

Microturbines are relatively quiet devices with a published sound level of 65 A-weighted decibels at 10 meters and would not impact neighbors. There are no odors or traffic associated with microturbines. Additionally, microturbines are pre-packaged within an enclosure and are low profile, therefore, would not impact the visual quality of the plant.

Figure 3-4 shows a site map with potential location of a microturbine project with gas conditioning included. Microturbines have a compact footprint and come shipped as containerized units, making it easy to accommodate them on the site.

Figure 3-4. Site layout of microturbine project with gas conditioning

3.3.4 Biosolids Drying

Biosolids drying received the highest score for proven technology performance and project site compatibility since this process is already in operation at the plant. However, with respect to energy recovery, using biogas in the biosolids dryer is the lowest financial value of biogas. There are no financial incentives available when biogas is used in the solids dryer, aside from offsetting NG use. Using biogas as a replacement for NG also introduces volatile organic compounds that must be treated in a regenerative thermal oxidizer.

3.3.5 Energy Storage

Energy storage via batteries is a proven technology, but have only recently been installed on a larger scale at treatment plants. Energy storage does not provide any resource recovery of biogas or generate any additional power — batteries strictly provide storage to lower non-coincident demand costs through energy arbitrage. Battery storage will not be carried forward to the SWEET analysis since it did not achieve an overall score greater than 3. Battery storage and microgrid controls may be reevaluated as a means to stabilize engine operation and performance when disconnected from the grid.

3.3.6 Solar PV

Solar PV options require minimal effort from O&M staff to operate and have a moderate capital cost. They scored the highest in energy and resource recovery because they utilize power from the sun and still allow for biogas to be used in the engine or solids dryer. There are no emissions from solar panels; therefore, they have minimal environmental impacts.

With respect to site capability, small-scale solar would be challenging to locate since the panels would need to be located on multiple buildings and locating them on the primaries or secondaries may be a corrosive, hazardous space that reduces access to the tanks. Input from EWA staff recommended putting small-scale solar (if used) on the aeration basins, which is the location highlighted in Figure 3-5. For large-scale solar, the large open area south of the EWPCF site was identified as a potential location. However, small or large-scale solar likely isn't required at the plant since 80 percent of the power demand is generated by the engines, leaving a relatively small amount of electricity usage charges that could be offset. Large-scale solar is most applicable if biogas is upgraded instead of used for power production – this leaves more available electricity consumption for offset. Large-scale solar options may be combined with net metering or energy storage to accommodate the excess power production. Figure 3-5 shows potential locations for solar PV panels at the plant.

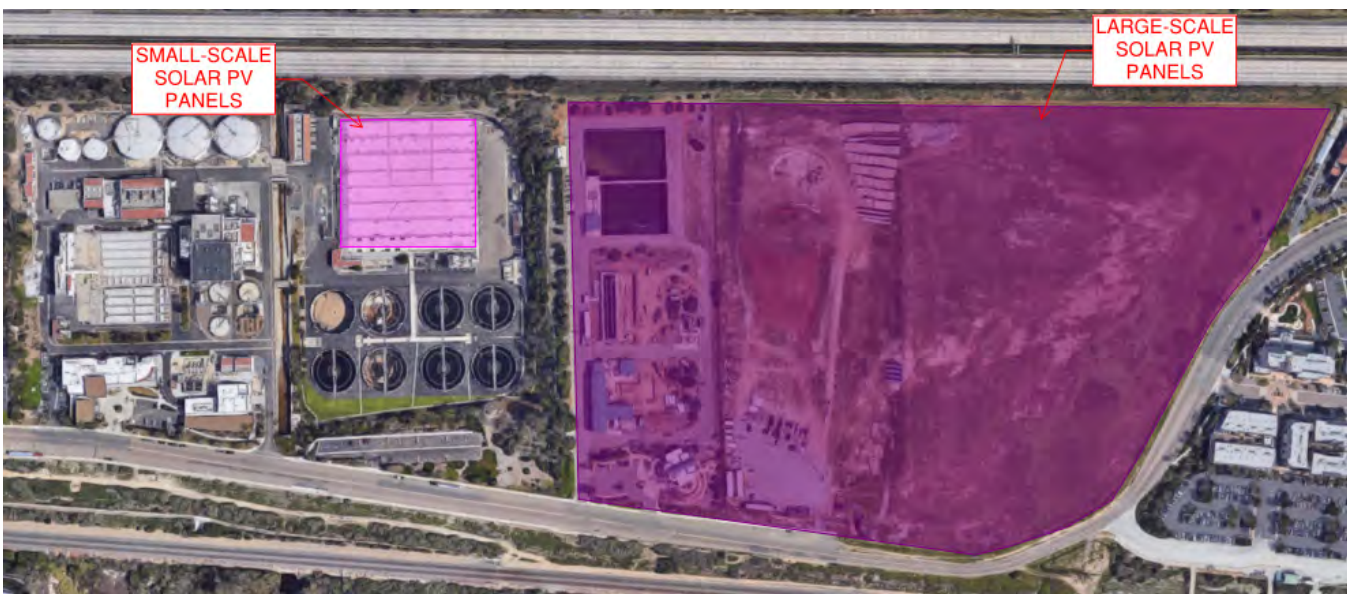

Figure 3-5. Potential siting for solar PV panels at EWPCF

Section 4: Conclusions and Next Steps

Screening of alternative power production resulted in a final selection of technologies to be included in end-to-end alternatives and are summarized in the list below. These technologies will be combined with the results of Tasks 2, 4, and 5 for the creation of end-to-end alternatives for analysis in the SWEET model. Factors influencing power production, such as gas treatment and codigestion (TM 4), will be paired with the power production technologies to aid in selection of the best overall alternative. Development of end-to-end alternatives will be performed in cooperation with EWA staff prior to analysis.

A shortlist of alternatives to be carried forward in SWEET analysis follows:

- Continued use of the existing IC engines
  - With gas conditioning
  - With gas conditioning plus SCR
- Biogas upgrading
  - Pipeline injection
  - On-site vehicle fueling
- Microturbines
- Biosolids drying – direct use of biogas
- Large-scale solar PV
- Small-scale/rooftop solar PV

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Attachment A: Workshop Meeting Minutes

August 16, 2017

Brown AND Caldwell

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Meeting Minutes

Prepared for: Encina Wastewater Authority
Project Title: Energy & Emissions Strategic Plan & Biosolids Management Plan Update
Project No.: 150871

Purpose of Meeting: Workshop #2 **Date:** August 16, 2017
Meeting Location: Encina Wastewater Authority **Time:** 1:30 – 5:00 PM
Minutes Prepared by: Hari Seshan and Jocelyn Lu, Brown and Caldwell

Attendees:		
	Doug Campbell, Encina, JPA	Adam Ross, Brown and Caldwell
	Scott McClelland, Encina JPA	Hari Seshan, Brown and Caldwell
	Jimmy Kearns, Encina JPA	Jocelyn Lu, Brown and Caldwell
	Mike Steinlicht, Encina JPA	Natalie Sierra, Brown and Caldwell
	Octavio Navarrete, Encina JPA	Scott Lacy, Brown and Caldwell
	Nathan Chase, RMC	Tom Chapman, Brown and Caldwell

Attachments:

- Workshop #2 Presentation Slides

Decisions

The following is a list of decisions made as a result of the meeting discussion:

- BC team to evaluate RDTs against the current status quo of primary clarifier and DAFT.
- Stabilization technologies that moved to the next round of evaluation: Mesophilic Digestion, Mesophilic Digestion with High Solids, Thermophilic Digestion, and Traditional CAMBI.
- Dewatering technologies that moved to the next round of evaluation: Centrifuges and Belt Presses.
- Post-dewatering technology that moved to the next round of evaluation: Thermal Drying - High Quality (Drum Dryer).
- Alternative power production technologies that moved to the next round of evaluation: Internal Combustion Engines (Status Quo), Internal Combustion Engines – with Gas Conditioning, Internal Combustion Engines – with Exhaust Treatment, Digester Upgrading – Pipeline Injection, Micro-Turbines, Biosolids Drying – Direct Use of Biogas, Large Scale Photovoltaics (PV), Small Scale Rooftop PV.
- Waste heat technologies that moved to the next round of evaluation: Small-Scale Steam Turbines, and Thermo/THP.

Action Required

The following is a list of actions required as a result of the meeting discussion:

- Jimmy to send Adam maintenance schedule costs.
- Octavio to send WAS daily flow data to Hari Seshan (Hari).
- Scott L to send list of additional data/document requests over to Scott M after updating based on discussion.
- Scott M to send a list of EWA attendees for the Waste Haulers Meeting to BC.
- Adam to send a draft agenda of the Waste Haulers meeting to EWA and finalize per any EWA comments.
- Octavio to send EWA's SDG&E point of contact to Adam. EWA and BC to discuss initial contact with SDG&E regarding biomethane pipeline injection.
- Octavio to send Hari lab data on the performance of the centrifuges.
- Tom to work with Octavio on refining the solids mass balance.
- Adam to present a big picture view of the power production alternatives at the next workshop.
- BC to identify technologies that would be beneficial to visit at WEFTEC.
- BC will set up a meeting with Anaergia to discuss project goals and opportunities. This meeting will be separate from the Waste Hauler meeting.
- Scott L and Scott M will schedule Workshop 3 for mid-September – aim for conducting the Waste Hauler meeting on the same day.
- EWA will take the dryer out of service in September/October. BC requests that any condition assessment results be shared with the team – particularly related to the increased use of digester gas (siloxane or hydrogen sulfide issues).
- BC to check in with EWA to confirm is any support is needed related to the next board meeting on Oct 11.

Summary

Workshop #2 was held for the Encina Water Authority (EWA) Energy & Emissions Strategic Plan & Biosolids Management Plan Update. The purpose of this Workshop was to review pending administrative tasks and provide task updates. A summary of the discussion is provided below:

<u>Introductory Items</u>

BC started off the meeting by reviewing the schedule and goals for the meeting. The goals are to generate content and direction for the project team moving forward.

- This month, the Brown and Caldwell (BC) team will be:
  - o Preparing a baseline report, to be reviewed by EWA in September.
  - o BC will also be preparing report sections of Tasks 2 and 3 by September.
  - o In October and November, BC will be developing SWEET alternatives and providing more clarity on how the pieces interact.
- Adam Ross (Adam) stated that he expects to have more questions about permitting, cogeneration (cogen), electrical rates, and where to send digester gas, and would appreciate dialogue between now and the next workshop. EWA staff recommended for him to work with Octavio Navarrete (Octavio).

New Data Request Items

BC reviewed new data request items with EWA. They included:

- Trussell food waste capacity report - Scott McClelland (Scott M) stated that he has the data, but not the report, on the Trussell study. Preliminary conclusions of the report indicate that EWA could accept an additional 80,000 gal/week of FOG and 25,000 gal/week of brewery waste. EWA expect it'll take about another month before the report is ready. Imported wastes are received Monday – Friday/Saturday. A constant feed to the digesters is provided until around Saturday afternoon. A potential limitation to high strength waste acceptance is truck offloading capacity. A food waste pilot program began on Monday, 9/14.
- O&M costs for cogen engines - Adam asks if EWA has annual O&M costs for the engines. Jimmy Kearns (Jimmy) states that EWA has annual costs for the maintenance schedule.
    - **ACTION: Jimmy to send Adam maintenance schedule costs.**
- WAS flow data
    - BC requests the WAS flow data, and Octavio indicates that EWA does have that data.
    - **ACTION: Octavio to send WAS daily flow data to Hari Seshan (Hari).**
- Air permitting summaries or progress
    - Doug Campbell (Doug) sent Adam the latest email from Don King (Don).

Outstanding Data Requests

BC reviewed outstanding data requests with EWA. They included:

- Cogen drawing and cut-sheets
    - Natalie Sierra (Natalie) points out that BC has received drawings from Andritz.
- Information on energy management
- High strength waste storage (typical day operating procedure)
- **ACTION: Scott L to send list of additional data/document requests over to Scott M after updating based on discussion.**

There was a subsequent discussion on wasted gas that was being flared. Octavio explains that the operators need to manually control the digester gas flow to the dryer, which results in some flaring. Operators generally try to set the digester gas flow rate to avoid drawing down the gas system and triggering natural gas blending at cogen. This typically results in a conservative offtake of digester gas to the dryer which results in some flaring. Mike Steinlicht (Mike) asks how much is being flared, and Adam calculated that about 180 kW of gas was being flared (averaged over a month) in current operation.

Cogeneration operation was discussed. EWA operates two engines on digester gas 24/7. A third engine operates on natural gas during peak power rates. EWA physically disconnects from the power grid to avoid demand and consumption charges.

FOG is fed to the digesters at a constant rate of 12 gallons per minute. FOG is fed to only one or two digesters, not all. The FOG feeding begins on Monday with first deliveries of the week, and continues into Saturday to pump down material from the last deliveries on Friday.

<u>Meeting with Waste Haulers</u>
BC reviewed the timing, attendees, and goals of the Waste Haulers Meeting. Below is a summary of the discussion:

- Scott L reviewed the potential list of attendees, which included: EWA representatives, BC representatives, Waste Management (WM), Republic, EDCO, and potentially LES or Anaergia.
    - **ACTION: Scott M to send a list of EWA attendees for the Waste Haulers Meeting to BC.**
- Scott M stated that the intent of the meeting is to develop a public-private partnership and noted increase grant eligibility by having this kind of relationship.
- Mike emphasized that the elected officials want all of the waste haulers at the table, especially those that operate within EWA's service area.
- Adam reviewed the draft Waste Hauler Agenda, which would cover background on the plant, current operation, and a discussion of potential capacity.
- Scott M stated that he would like to have an agenda finalized and sent out to each waste hauler 30 days in advance of the meeting, to give them adequate prep time.
    - **ACTION: Adam to send a draft agenda of the Waste Haulers meeting to EWA and finalize per any EWA comments 30-days in advance of the meeting.**
- Adam stated that another discussion point for the meeting is the waste haulers potential interest in accepting compressed natural gas (CNG). Scott M stated that SDG&E should be involved in these conversations as well. A meeting should be arranged with SDG&E.
    - **ACTION: Octavio to send EWA's SDG&E point of contact to Adam.**
- Different gas delivery options, tube trailer vs. pipeline, were discussed. Adam stated that a tube trailer has less stringent standards than a pipeline, but there would be tube trucks coming in and out of the facility. However, the pipeline would have more stringent sampling/reporting requirements and the investment for an interconnection for the pipeline could cost $1 – 2 million dollars. This will be developed as the alternatives analysis is advanced.

<u>Other Outstanding Items</u>
BC reviewed their understanding of the discussion with Anaergia:

- Adam stated that Anaergia is promoting Omnivore as a process treatment option, which may or may not be the right fit at EWA. However, there might be opportunity for Anaergia to work with waste haulers for pre-processing food waste.

<u>Review of Mass Balance and Project Flows and Loads</u>
BC presented the project flows and loads:

- Mass Balance
    - Hari reviewed the assumptions made to calculated WAS. Octavio responded that the actual WAS flow is around 0.75 MGD, and that he could send that data to BC (ACTION above).
    - Adam stated that the VSR value of 65% seemed suspiciously high. Octavio stated that EWA's VSR value was closer to 55%.
    - Hari stated that the centrifuge % capture right now is 78%. Octavio responded that the capture rate for the centrifuges is consistently 95%, and that the calculated value is probably lower because of values during start-up and shut-down.
        - **ACTION: Octavio to send Hari lab data on the performance of the centrifuges.**

  - Tom requested that the BC team review the data with Octavio after he send is to BC.
    - **ACTION: Tom to send up conference call with Octavio after reviewing the data.**
- Solids Mass Balance Comparison
  - Tom presented a graph that shows that BC's calculated solids loading was higher than the calculated values in the Process Master Plan (2016).
  - Octavio stated that one reason for the increase might be a 2015 change in how EWA sampled the influent flow.
  - **ACTION: Tom to work with Octavio on refining the solids mass balance.**
- Power Loads and Gas Usage
  - Adam reviewed the gas usage graphs with EWA.
  - Digester Gas Usage Summary – Total gas production is trending up, probably due to the increase in high strength waste deliveries. Adam pointed out that the yellow "Total Gas Production" line didn't match up with the top of the bars, which is normal. Scott M pointed out that the important part is that the yellow line followed the same trend as the bars.
  - Natural Gas Usage Summary - Most of the natural gas is being used for the heat dryer and cogen, which is expected.
  - Power Production and Import – Currently, EWA is making about 80% of their electricity needs. This means that EWA could potentially export power. A look into the SDG&E power bills also showed that the actual kWh power that EWA is purchasing only constitutes $10,000 out of a $70,000 bill. The majority of the bill is non-coincident and standby power.
    - Mike stated that he had talked to SDG&E about the standby charges and haven't been able to get around them.
- Engine Fuel Use
  - Octavio explained that the increase in natural gas in November 2015 was because they needed to switch to natural gas to stay below emission limits.

<u>Screening of Technologies</u>

BC the fatal flaw filter and evaluation criteria, and then evaluated each process technology against that criteria. The results of the evaluation are summarized below and more details are included in the attached Workshop #2 PowerPoint slides.

- There were four fatal flaw filters:
  - At least one successful North American installation of the technology
  - At least one successful installation in a facility of similar size
  - There is available space to implement that technology
  - Compatibility with plant size and any existing equipment
- The technologies that passed the fatal flaw filter were then scored for each evaluation criteria, which included: end use market compatibility, proven technology performance, life cycle costs, energy/resource recovery, O&M impacts, environmental impacts, community and stakeholder impacts, and project site combability.
  - Each evaluation criteria was then weighted to reflect EWA's priorities.

  - Technologies that scored lower than a 3 were eliminated, and technologies that scored greater than a 3 would be evaluated through the SWEET model.
  - O&M impacts criteria will be clarified to describe reduction in O&M staff time.
- Thickening Technologies
  - Prior planning efforts recommended evaluating rotary drum thickeners (RDTs) against the existing primary clarifier and dissolved air flotation thickeners (DAFTs). EWA concurred with that recommendation.
  - Natalie asked if the team should add Anaergia's Omnivore to the list of technologies to evaluate. Scott L proposed that that decision to be made after a meeting with Anaergia takes place.
    - **DECISION: BC team to evaluate RDTs against the current status quo of primary clarifier and DAFT.**
- Stabilization Technologies
  - Technologies that failed the fatal filter: Staged Digestion, Acid/Gas Phased Digestion, Temperature Phased Anaerobic Digesion, Enzymatic Hydrolysis, Chemical Hydrolysis, THP – DLD, and Solid Stream CAMBI.
  - Technologies that scored lower than a 3 in the evaluation criteria: Lystek.
  - **(DECISION) Stabilization technologies that moved to the next round of evaluation: Mesophilic Digestion, Mesophilic Digestion with High Solids, Thermophilic Digestion, and Traditional CAMBI.**
- Dewatering Technologies
  - Technologies that failed the fatal filter: Bucher Press.
  - Technologies that scored lower than a 3 in the evaluation criteria: Screw Press, Rotary Press, and Volute Press.
  - **(DECISION) Dewatering technologies that moved to the next round of evaluation: Centrifuges and Belt Press.**
- Post-Dewatering Technologies
  - Technologies that failed the fatal filter: Thermal Drying: Low Quality (Indirect Dryer), Gasification, and Pyrolysis.
  - Technologies that scored lower than a 3 in the evaluation criteria: N/A
  - **(DECISION) Post-dewatering technologies that moved to the next round of evaluation: Thermal Drying: High Quality (Drum Dryer).**
- Alternative Power Production Technologies
  - Technologies that failed the fatal filter: Fuel Cells and Wind Turbines.
  - Technologies that scored lower than a 3 in the evaluation criteria: Energy Storage (Batteries), Large Scale Solar Photovoltaics
  - **(DECISION) Alternative power production technologies that moved to the next round of evaluation: Internal Combustion Engines (Status Quo), Internal Combustion Engines – with Gas Conditioning, Internal Combustion Engines – with Exhaust Treatment, Digester Upgrading – Pipeline Injection, Micro-Turbines, Biosolids Drying – Direct Use of Biogas, Large-Scale Solar Photovoltaics (PV), and Small Scale Rooftop PV.**
- Waste Heat Technologies
  - Technologies that failed the fatal filter: Absorption and Adsorption Chillers, Organic Rankine Cycle, and Gasification of Biosolids.

- Technologies that scored lower than a 3 in the evaluation criteria: N/A
- **(DECISION) Waste heat technologies that moved to the next round of evaluation: Small-Scale Steam Turbines, and Thermo/THP.**

<u>**Creation of End to End Alternatives**</u>
The BC team reviewed initial alternatives that were to be evaluated, as well as different power production alternatives. The power production alternatives included:

- Baseline: existing cogen and drying
- Baseline with gas conditioning
- Existing cogen with vehicle fuel (via pipeline injection or tube trailer)
- Existing cogen with microtubines
- Existing cogen with steam boiler/turbine
- New cogen permit, CO catalyst and selective catalytic reduction (SCR), with gas conditioning
- Vehicle fuel (primary use of digestive gas) with existing cogen
- **ACTION: Adam to present a big picture view of the power production alternatives at the next workshop.**

<u>**Grant Updates**</u>
BC provided an overview of different grant programs, and explained how the program would fit into the SWEET model. The programs included:

- Self-Generation Incentives Program
- Low Carbon Fuel Standard
- Renewable Fuel Standard
- Organics Grant Program
- Healthy Soils Program
- Green Project Reserve

<u>**Air Permitting Discussion**</u>
BC and EWA discussed the current efforts of the air permit modification. EWA is submitting a request for permit modification in one week. If successful, it would increase the permitted cogen capacity by ~20%.

<u>**Look Ahead & Wrap-Up**</u>
The meeting ended with a look ahead and reviewing pending action items.

- Workshop #3 will take place in mid-September, and the team will try to schedule the Waste Hauler Meeting on the same day.
- The team will present the following in Workshop #3:
  - Baseline SWEET model
  - Conceptual layouts and details of alternatives for consensus and feedback
  - Air permitting impacts on power production alternatives
  - Grant updates
- WEFTEC is also taking place in early-October. Mike stated that it would be beneficial to walk the floor together with BC to look at potential technologies.
  - **ACTION: BC to identify technologies that would be beneficial to visit at WEFTEC.**

- ACTION: BC to check in with EWA to confirm is any support is needed related to the next board meeting on Oct 11.

Brown AND Caldwell

Energy & Emissions Strategic Plan & Biosolids Management Plan Update

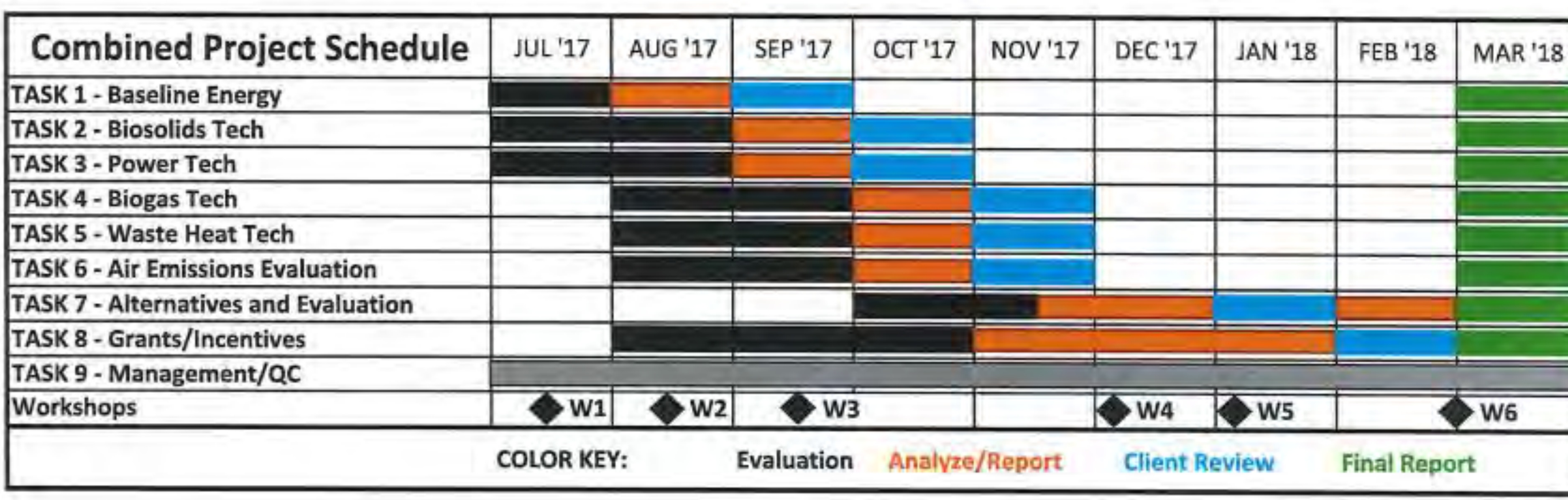
ENCINA WASTEWATER AUTHORITY

Workshop #2 – August 16, 2017

Encina Water Pollution Control Facility

Project Schedule

- Progress On Schedule
- Task 1 Energy Baseline Complete
- Other Tasks (except 7) are Under Way
- Workshop #2 Today



Agenda

- Administrative (20 min)
  - Status of data requests
  - Comments on waste hauler agenda
  - Discussion with Anaergia
- Review Mass Balance and Projected Flows and Loads (45 min)
- Review Fatal Flaw and Screening Criteria (30 min)
- Screen Technologies (1 hr)
- Discussion of Preliminary End to End Alternatives (30 minutes)
- Grants Update (10 min)
- Air Emissions Review (5 min)
- Wrap-Up/Review Action Items (10 min)

New Data Requests

- Trussell food waste capacity report
- O+M costs for the engines (have costs for electricity for the system, but not for gas treatment, upkeep, general maintenance, etc.)
- WAS daily flow data (back-calculated for mass balance)
- FOG TS and VS data (used assumptions from 2016 PMP for mass balance)
- Any air permitting summaries or progress between EWA and Don King

Outstanding Data Requests

- Cogen and solids systems drawings, engine cut sheets
- Dryer system drawings and cut sheets
- Recent air permitting efforts – progress, memos, contact info
- Copies of current air permits (SDAPCD and Title V)
- Energy Management – typical day operating procedure:
  - Cogen strategy
  - Peak period disconnect from utility
  - HSW storage and feed strategy

Waste Hauler Agenda

- Timing: September (coordinate with Workshop 3)
- Attendees:
  - EWA – Scott, Jimmy
  - BC – Adam, Ari
  - WM
  - Republic
  - EDCO
  - LES?
  - Anaergia?
- Goals:
  - Provide background info to haulers about EWA's goals and BEE effort
  - Determine availability of pre-processed food waste, market demand for an EWA initiative to receive more material, tipping fee range for SWEET analysis
  - Gauge interest in a renewable CNG partnership
  - Discuss "next steps" such as letter of intent, future coordination

Other Outstanding Items

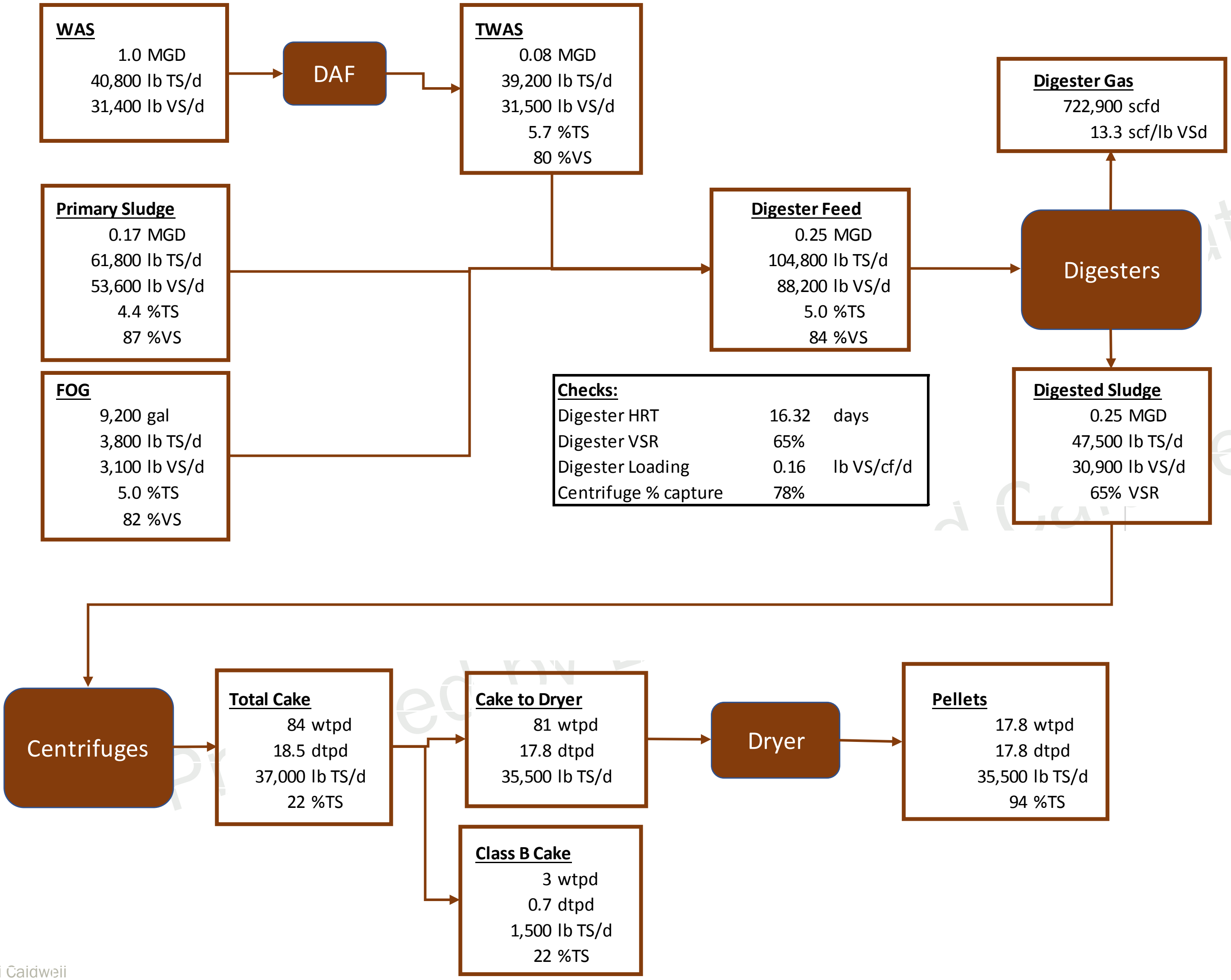
- Discussion with Anaergia
  - Omnivore as an alternative
  - Orex or Biorex for food waste pre-processing
  - Status of food waste receiving project(s) with Republic
  - Capacity at Rialto facility for dried product?

Review of Mass Balance and Projected Flows and Loads

Brown AND Caldwell

Mass Balance

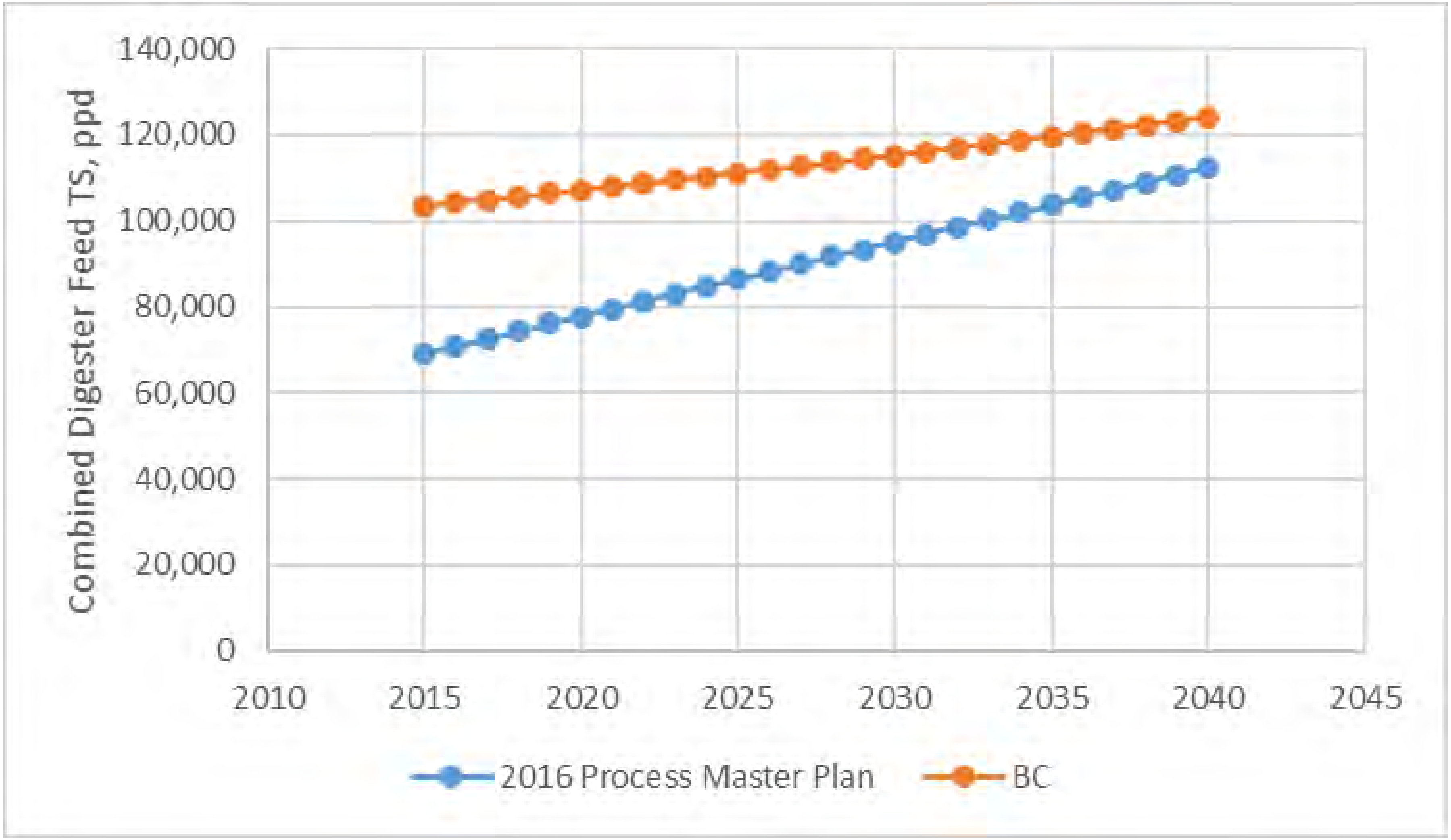
MAY 2015 - JUNE 2017



Mass Balance Assumptions

- TWAS flows that were zero and subsequent loads when TWAS flow was zero were excluded. Assumed percent capture rate for the DAFTs is 95%.
- TWAS flows were taken from DAFT totalizer data and digester feed meters.
- The digester feed flow from July 1, 2016 to June 2017 were subtracted daily to obtain a daily digester feed volume. This was based on the assumption that the flow values were cumulative from a meter reading starting 7/1/16.
- The Class B cake data were averaged with zero data to obtain an annualized daily average.
- FOG data were a daily average of the volumes received. This assumes FOG is fed 24/7/365. Assumes %TS and %VS are 5% and 82%, respectively.
- To calibrate the mass balance as shown, 2,300 lbs TS/d and 1,900 lbs VS/d were added to Primary Sludge.

Solids Mass Balance Comparison



Sludge Production Peaking Factors

	Max Month	Peak 2-Week	Peak Week	Peak Day
Primary Sludge	1.23	1.3	1.4	1.60
WAS	1.23	1.3	1.4	1.60
Combined Sludge	1.23	1.3	1.4	1.60

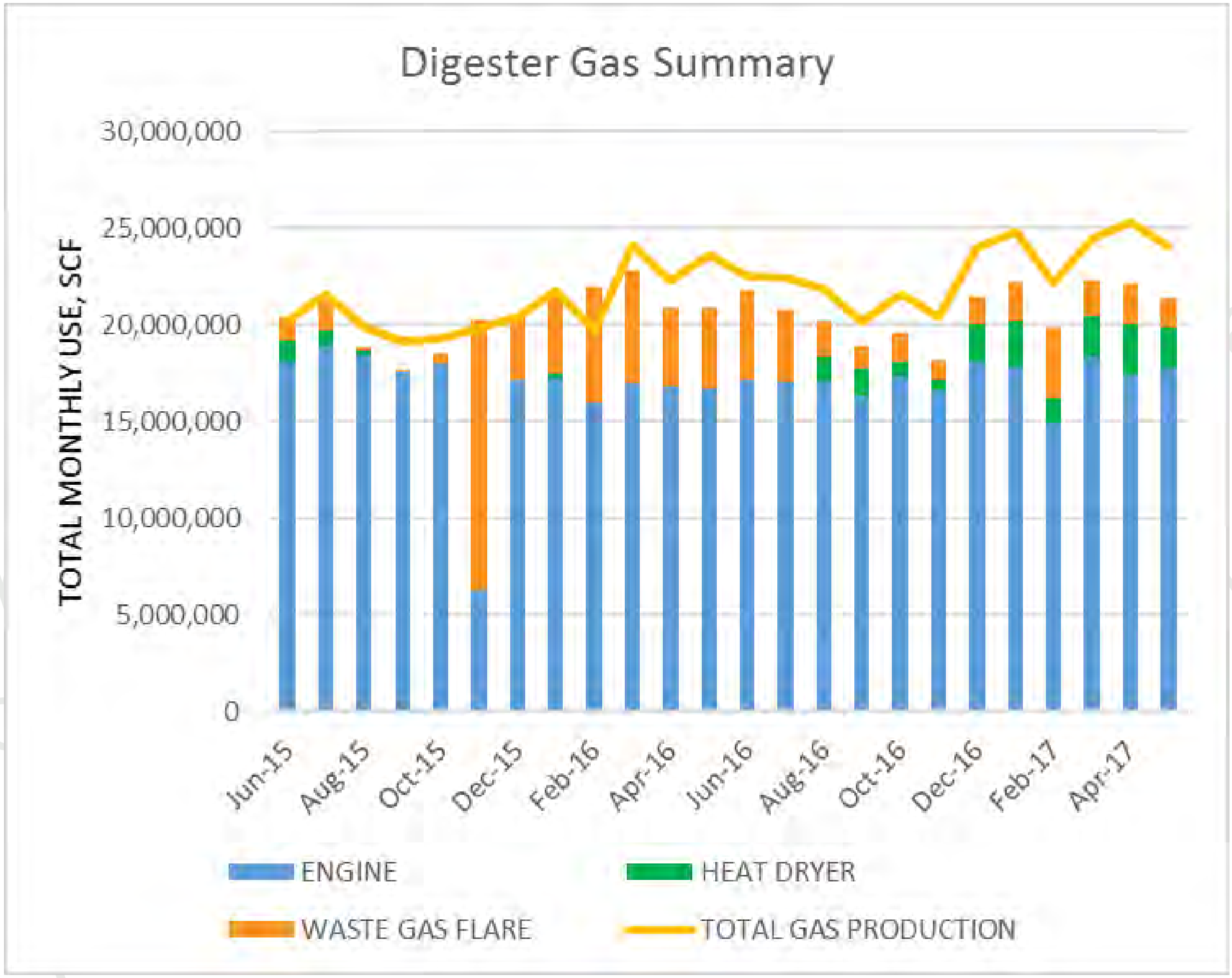
Notes:

- Peaking factors for maximum month and peak day conditions are developed based on 2016 PMP solids projections.
- Peaking factors for maximum 2-week and maximum week conditions are proposed based on historical data.

Power Loads and Gas Usage

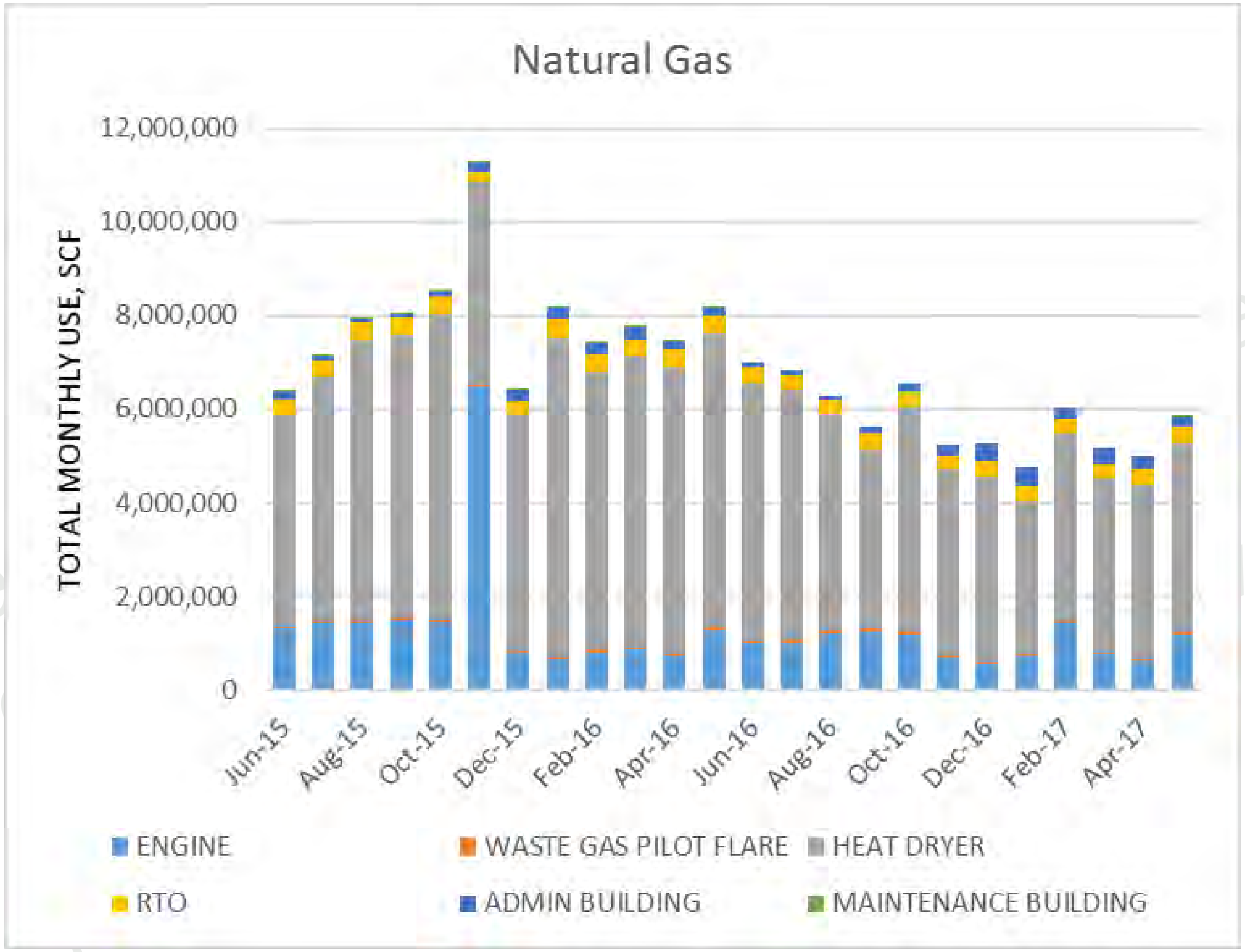
- Power:
  - Monthly production: 1,500 kW (2, 750 kW engines full output – 80% of total electrical demand)
  - Monthly import: 385 kW equivalent (1,390 MWh per year)
- Digester gas:
  - Average production: 1,645,000 therms per year
  - Engines: 1,263,000 therms per year
  - Waste gas: 229,000 therms per year
  - Heat dryer: 57,000 therms per year
- Natural gas: 856,000 therms per year
  - Engines: 156,000 therms/year
  - Other plant use: 700,000 therms/year

Digester Gas Usage Summary – Last 2 years



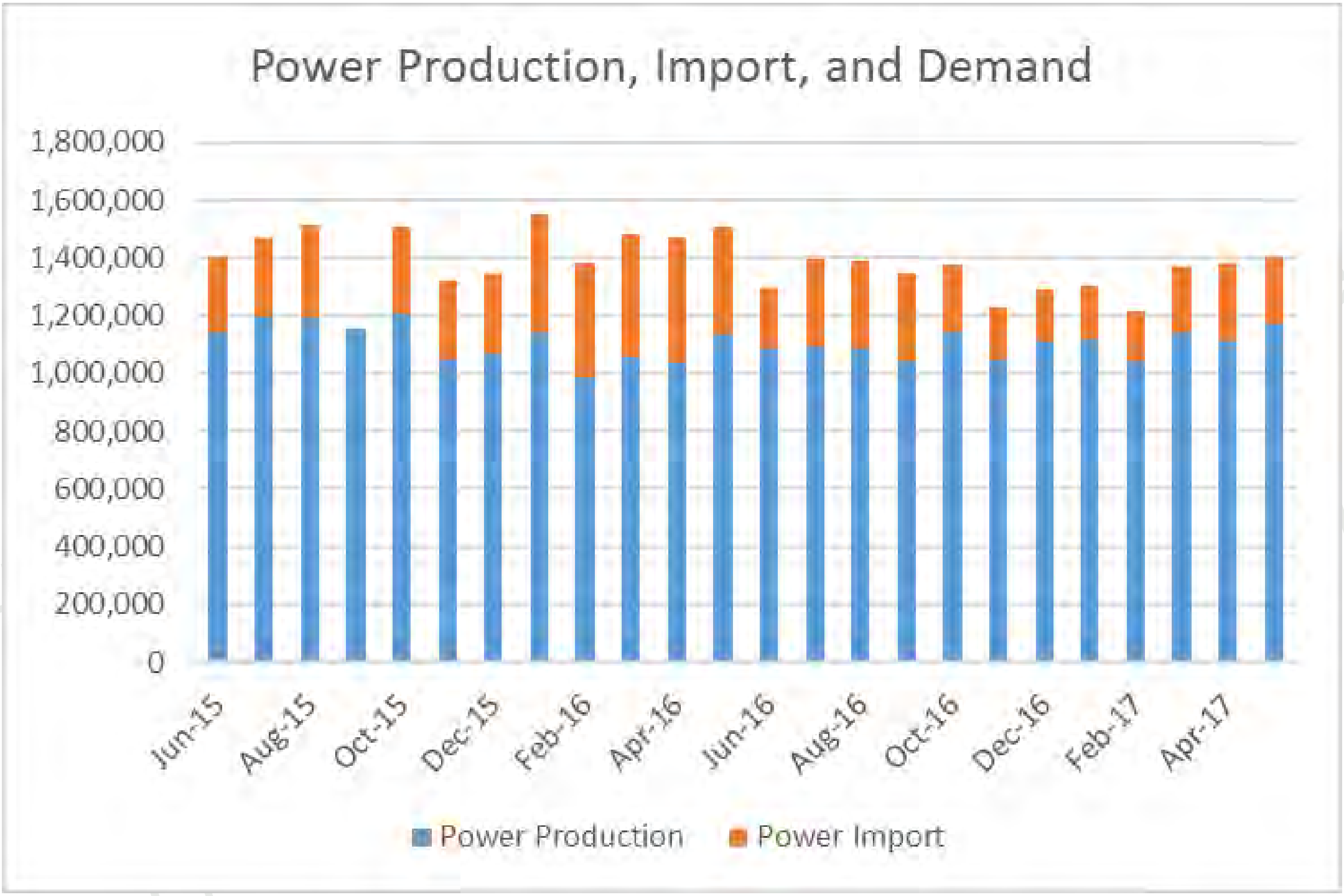
1) What happened November 2015? DG outage?
2) Divergence of "total gas production" from sum of other meters
3) When DG is sent to the heat dryer, what contributes to flaring?
4) Flared gas, over the course of the last year, represents 179 kW of "potential" power production

Natural Gas Usage Summary – Last 2 years



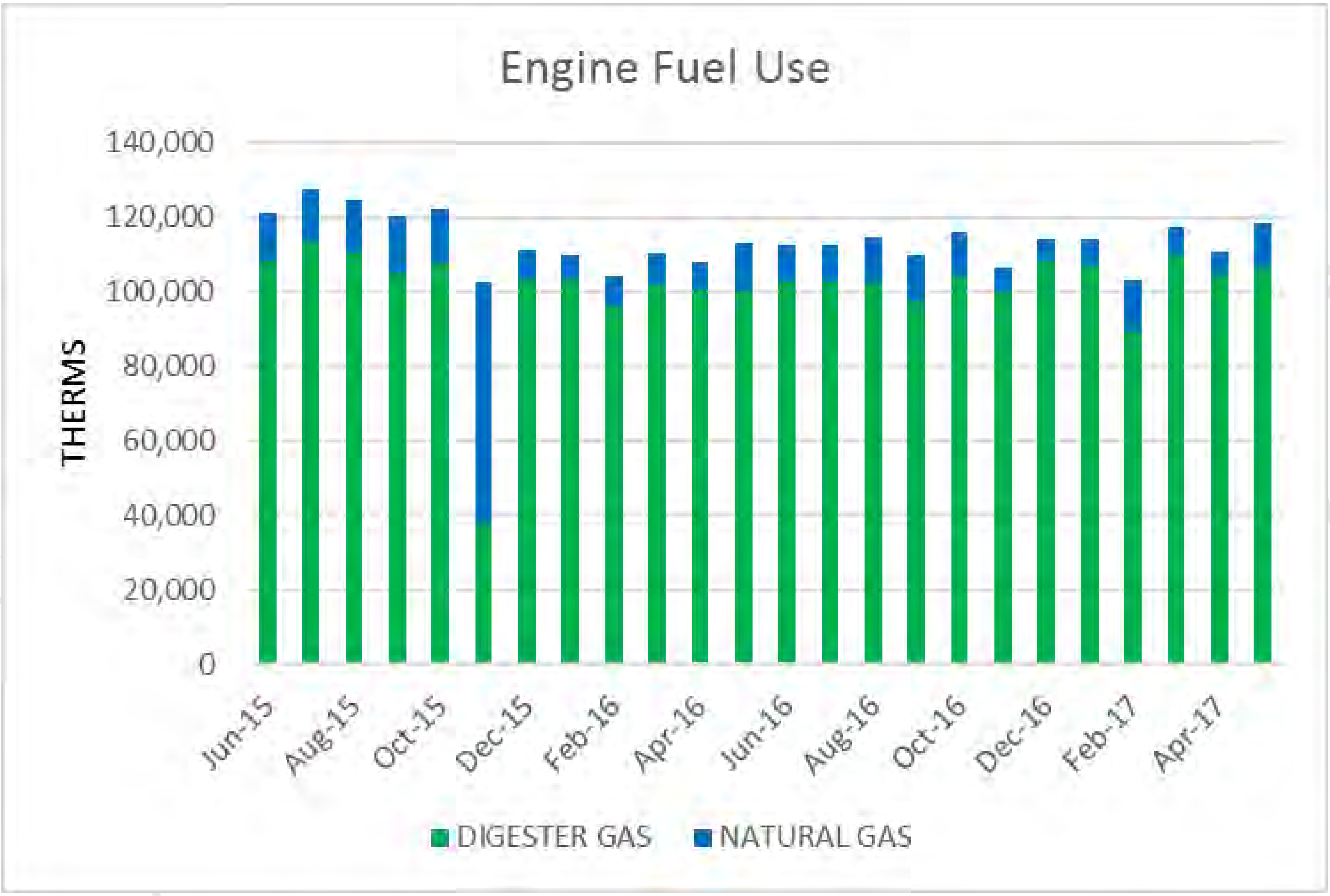
1) What is the NG control strategy to cogen? Why is there NG contribution to cogen in months where DG is being sent to dryer or flare?

Power Production and Import – Last 2 years



1) Consistently operating at 2-engine output
2) Operating a third engine at full output (if DG production increases and/or permit is modified) would result in power export

Engine Fuel Use– Last 2 years



1) Consistent operation
2) What is NG blending strategy?

Screening of Technologies

Fatal Flaw Filter

- Applied uniformly across all technologies
- Four criteria:
  - At least one successful North American installation of technology
  - At least one successful installation in a facility of similar size
  - Available space
  - Compatibility with plant size and any existing equipment

Evaluation Criteria

Criterion	Criterion Description	Scoring Description
End Use Market Compatibility	• Onsite technology directly produces one of the recommended product alternatives. • Alternately, onsite technology product is compatible with product alternatives.	• **Low score** indicates technology product that has not been identified as part of the product list nor compatible with the product list. **High score** indicates technology product that is compatible with Class B cake, Class A cake, Class A THP cake, and dried Class A pellet.
Proven Technology Performance	• Proven and reliable technology with same configuration intended at Encina. • Long successful operating track record.	• **Low score** indicates no successful large scale operating installations in North America or Europe, no successful demonstration scale installations in North America or Europe, and unknown safety or reliability record. • **High score** indicates more than one successful operating installation in North America or Europe, more than one operating installation at a WWTP of at least 40 mgd in North America or Europe, track record duration > 5 years, and vendors in Western USA.
Minimize Life Cycle Costs	• Qualitative metric of program cost. • Capital and O&M costs based on existing Encina data or similar experience at other WWTPs. • Potential revenues from sales. • Product/market geographic proximity.	• **Low score** indicates high capital cost to build onsite facilities, high O&M costs, expensive end use market, and high transportation costs. • **High score** indicates low capital cost to build onsite facilities, low O&M costs, potential product revenue, and product destination within 100 miles.

Evaluation Criteria (cont.)

Criterion	Criterion Description	Scoring Description
Energy/Resource Recovery	• Increases biogas production through advanced digestion. • Supports co-digestion of organic waste. • Recovery of renewable energy. • Beneficial use of biosolids product.	• **Low score** indicates high energy requirement for onsite technology, no increase in biogas production, technology does not recover energy as biogas, no recovery of renewable energy in biosolids, and no biosolids resource recovery. • **High score** indicates a higher biogas production, compatible with co-digestion of organic waste, and biosolids resource recovery.
O&M Impacts	• Impacts to existing plant O&M staff levels. • Complexity of new technology O&M and control systems. • Reliability of new technology (potential downtime). • Minimal impacts to plant safety.	• **Low score** indicates more O&M time required, complex mechanical and control systems required compared with existing plant facilities, potential equipment downtime, and new chemicals or hazards. • **High score** indicates reduction in O&M staff time required, new technology is simple to operate and maintain, reliable with minimal downtime, and no new chemicals or hazards.

Evaluation Criteria (cont.)

Criterion	Criterion Description	Scoring Description
Environmental Impacts	• Impacts to carbon footprint and air permitting.	• **Low score** indicates high carbon footprint for technology, high travel distance to end use, difficult to treat side-streams or impacts to GWRS, and new permitting for environmental regulatory requirements. • **High score** indicates low carbon footprint for technology, low travel distance to end use, minimal side-stream generation or impacts, no additional permitting for environmental regulatory requirements.
Community & Stakeholder Impacts	• Minimize nuisance impacts such as dust, odors, vectors, aesthetics, noise and traffic. • Assess impacts to partner agency issues/values as well as local planning codes and requirements.	• **Low score** indicates nuisance factors for onsite technology are difficult to mitigate. • **High score** indicates nuisance factors can be mitigated at plant site.
Project Site Compatibility	• Assess compatibility of technology with available plant footprint. • Incorporation into existing treatment process. • Ability to accept co-digestion substrates.	• **Low score** indicates lack of site space for new facilities, requires abandonment of existing facilities, and difficult integration with existing plant. • **High score** indicates available footprint for new facilities and maintains space for future facilities, easy of integration with existing processes and facilities.

Evaluation Criteria Weighting

Criterion	Weight Stabilization	Weight Dewatering	Weight Biogas Use and Waste Heat
End Use Market Compatibility	15%	15%	NA
Proven Technology Performance	15%	25%	20%
Minimize Life Cycle Costs	10%	20%	10%
Energy/Resource Recovery	20%	NA	25%
O&M Impacts	10%	15%	10%
Environmental Impacts	10%	5%	15%
Community & Stakeholder Impacts	10%	5%	10%
Project Site Compatibility	10%	15%	10%

Thickening Technologies

- Primary Clarifier (Existing)
- DAFT (Existing)
- Rotary Drum Thickener (RDT)
- Recommendation from prior planning efforts used to evaluate RDTs compared to status quo

Starting with the End in Mind – Market Compatibility

- Class B Cake – Land application (Arizona) or contract composting
- Class A Cake – Land application in CA and AZ (soil blending and land reclamation possible)
- Class A THP Cake – Land application and soil blending (land reclamation possible)
- Class A granules (high quality) – Land application, horticulture, fertilizer blending, soil blending (land reclamation possible)
- Class A granules (low quality) – Land application (land reclamation possible)
- Class A Lystegro – Land application

Options to produce end-use product alternatives

Product Alternatives	Technology Options
Class B Cake	Class B digestion
Class A Cake	Class A digestion (thermophilic or TPAD)
Class A THP Cake	THP/digestion
Class A Dried Granule (high quality)	Class A or B digestion + two dryer trains
Class A Dried Granule (low quality)	Class A or B digestion + maximize existing dryer
Class A Lystegro	Class A or B digestion + Lystek

Stabilization Technologies

- Mesophilic Digestion
- Mesophilic High Solids Digestion
- Staged Digestion
- Acid/Gas Digestion
- Thermophilic Digestion
- Temperature Phased Anaerobic Digestion (TPAD)
- Enzymatic Hydrolysis
- Chemical Hydrolysis
- Lystek
- Thermal Hydrolysis Process (THP) – Traditional CAMBI
- THP – Digestion-Lysis-Digestion (DLD)
- THP – Solid Stream CAMBI

Stabilization Technologies – Fatal Flaw

	Technology Maturity	Successful Operation of Comparable Size	Available Space	Compatibility
Mesophilic Digestion	Pass	Pass	Pass	Pass
Mesophilic with High Solids	Pass	Pass	Pass	Pass
Staged Digestion	Pass	Pass	Fail	Pass
Acid/Gas Phased Digestion	Pass	Pass	Fail	Pass
Thermophilic Digestion	Pass	Pass	Pass	Pass
Temperature Phased Anaerobic Digestion	Pass	Pass	Fail	Pass
Enzymatic Hydrolysis	Fail	Fail	Pass	Pass
Chemical Hydrolysis	Pass	Fail	Pass	Pass
Lystek	Pass	Pass	Pass	Pass
Traditional CAMBI	Pass	Pass	Pass	Pass
THP - DLD	Fail	Fail	Fail	Pass
Solid Stream CAMBI	Fail	Fail	Pass	Pass

Stabilization Technologies - Screening

	Mesophilic Digestion	Mesophilic Digestion with High Solids	Thermophilic Digestion	Lystek	Traditional CAMBI
End Use Market Compatibility	3	3	3	2	5
Proven Technology Performance	5	2	5	2	4
Minimize Life Cycle Costs	3	3	4	2	2
Energy/Resource Recovery	3	4	5	3	4
O&M Impacts	4	3	4	3	3
Environmental Impacts	4	4	4	3	4
Community & Stakeholder Impacts	4	4	4	2	4
Project Site Compatibility	5	3	5	3	2
Weighted Score	**3.80**	**3.25**	**4.30**	**2.50**	**3.65**

Dewatering Technologies

- Centrifuge
- Belt press
- Screw press
- Rotary press
- Volute press
- Bucher press

Dewatering Technologies – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Centrifuges	Pass	Pass	Pass	Pass
Belt Press	Pass	Pass	Pass	Pass
Screw Press	Pass	Pass	Pass	Pass
Rotary Press	Pass	Pass	Pass	Pass
Volute Press	Pass	Pass	Pass	Pass
Bucher Press	Fail	Fail	Pass	Pass

Dewatering Technologies - Screening

	Centrifuges	Belt Press	Screw Press	Rotary Press	Volute Press
End Use Market Compatibility	3	5	4	3	3
Proven Technology Performance	5	5	3	2	2
Minimize Life Cycle Costs	4	4	3	3	3
O&M Impacts	5	5	2	2	2
Environmental Impacts	3	2	3	3	3
Community & Stakeholder Impacts	4	4	4	4	4
Project Site Compatibility	5	4	2	3	3
Weighted Score	**4.35**	**4.45**	**2.90**	**2.65**	**2.65**

Post-Dewatering Technologies

- Thermal drying – high quality granules
- Thermal drying – low quality granules (indirect dryer)
- Gasification
- Pyrolysis
- Partial solar drying
- Deep well injection
- Dehydration
- Incineration

Post-Dewatering Technologies – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Thermal Drying: Low Quality (Indirect Dryer)	Pass	Pass	Pass	Fail
Thermal Drying: High Quality (Drum Dryer)	Pass	Pass	Pass	Pass
Gasification	Fail	Fail	Pass	Pass
Pyrolysis	Fail	Fail	Pass	Pass

Alternative Power Production Technologies

- Internal Combustion Engines
- Digester gas upgrading
  - For pipeline injection
  - For vehicle fueling (CNG)
- Microturbines
- Biosolids Drying – direct use of biogas
- Energy Storage (Batteries)
- Fuel Cells
- Large Scale Solar Photovoltaics (PV)
- Small Scale/Rooftop Solar Photovoltaics
- Wind Turbines
- Direct sale to adjacent power plant

Alternative Power Production – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Internal Combustion Engines	Pass	Pass	Pass	Pass
Digester Upgrading: Pipeline Injection	Pass	Pass	Pass	Pass
Digester Upgrading: Vehicle Fueling (CNG)	Pass	Pass	Pass	Pass
Microturbines	Pass	Pass	Pass	Pass
Biosolids Drying - Direct Use Of Biogas	Pass	Pass	Pass	Pass
Energy Storage	Pass	Pass	Pass	Pass
Fuel Cells	Fail	Fail	Pass	Pass
Large Scale Solar Photovoltaics	Pass	Pass	Pass	Pass
Small Scale/Rooftop Solar Photovoltaics	Pass	Pass	Pass	Pass
Wind Turbines	Pass	Pass	Fail	Fail

Alternative Power Production – Screening

	Internal Combustion Engines - Status Quo	Internal Combustion Engines - With Gas Conditioning	Internal Combustion Engines - With Exhaust Treatment	Digester Upgrading: Pipeline Injection	Digester Upgrading: Vehicle Fueling (CNG)	Micro-turbines	Biosolids Drying - Direct Use Of Biogas	Energy Storage (Batteries)	Small Scale Rooftop PV	Large Scale Photovoltaics
Proven Technology Performance	5	5	4	2	3	4	5	3	5	5
Minimize Life Cycle Costs	3	3	4	4	4	3	3	3	4	4
Energy/Resource Recovery	4	4	5	4	4	4	2	1	5	5
O&M Impacts	3	4	3	4	4	4	3	4	5	5
Environmental Impacts	3	3	4	5	5	5	3	3	5	4
Community & Stakeholder Impacts	4	4	5	5	5	4	3	3	5	5
Project Site Compatibility	5	5	4	4	4	4	5	3	2	2
Weighted Score	**3.95**	**4.05**	**4.25**	**3.85**	**4.05**	**4.05**	**3.35**	**2.60**	**4.60**	**4.45**

Waste Heat Technologies

- Small Scale Steam Turbines
- Thermo/THP
- Absorption and Adsorption Chillers
- Organic Rankine Cycle (ORC)
- Gasification of Biosolids

Waste Heat Technologies – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Small Scale Steam Turbines	Pass	Pass	Pass	Pass
Use For Thermo/THP	Pass	Pass	Pass	Pass
Absorption And Adsorption Chillers	Pass	Pass	Pass	Fail
Organic Rankine Cycle	Fail	Fail	Pass	Pass
Gasification Of Biosolids	Fail	Fail	Pass	Pass

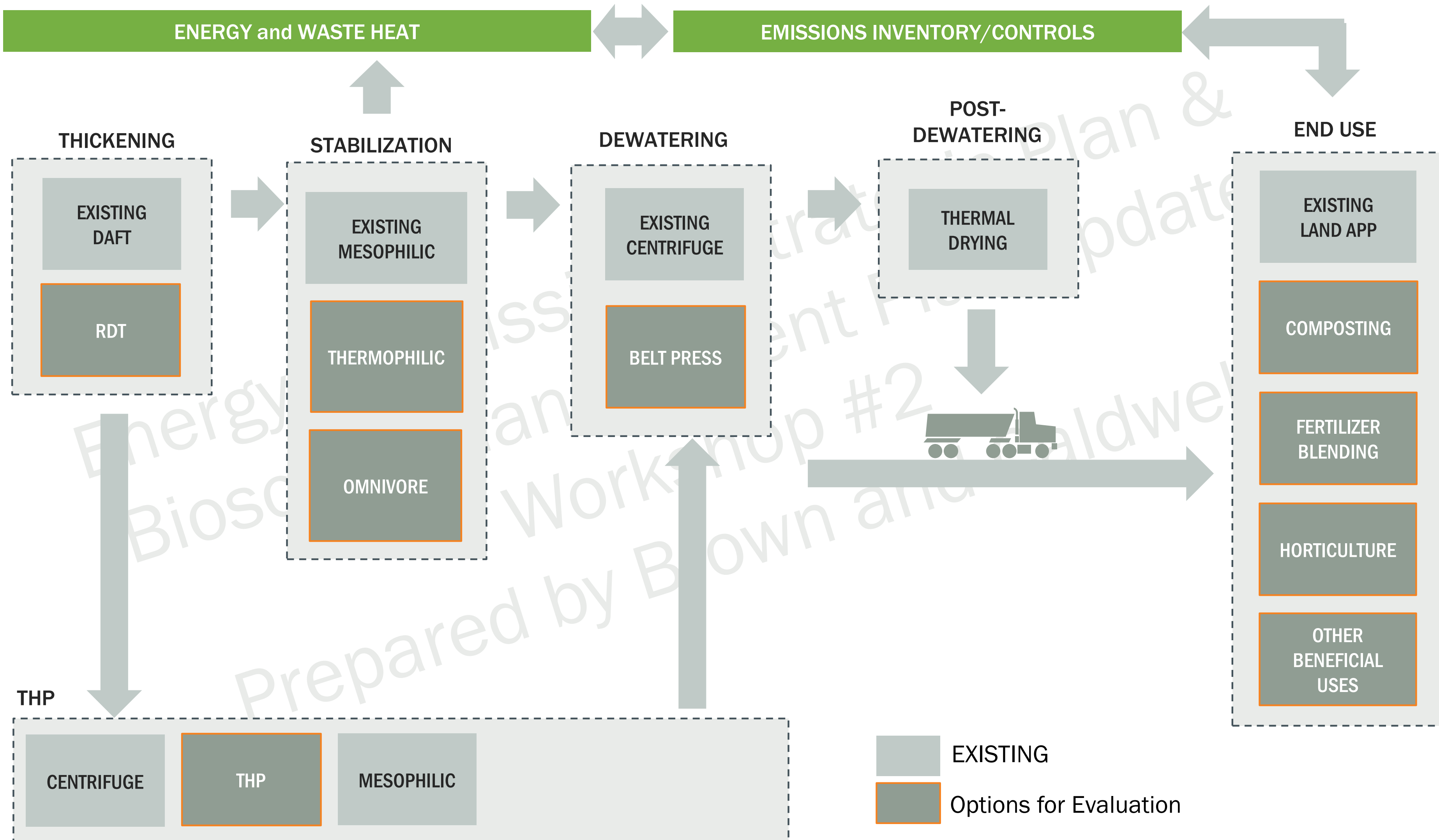
Waste Heat Technologies – Screening

	Small-Scale Steam Turbines	Thermo/THP
Proven Technology Performance	2	5
Minimize Life Cycle Costs	3	5
Energy/Resource Recovery	4	4
O&M Impacts	3	3
Environmental Impacts	3	4
Community & Stakeholder Impacts	3	4
Project Site Compatibility	3	4
Weighted Score	**3.05**	**4.2**

Creation of End to End Alternatives

Brown AND Caldwell

Evaluating Technologies and Markets Together



Initial Alternatives

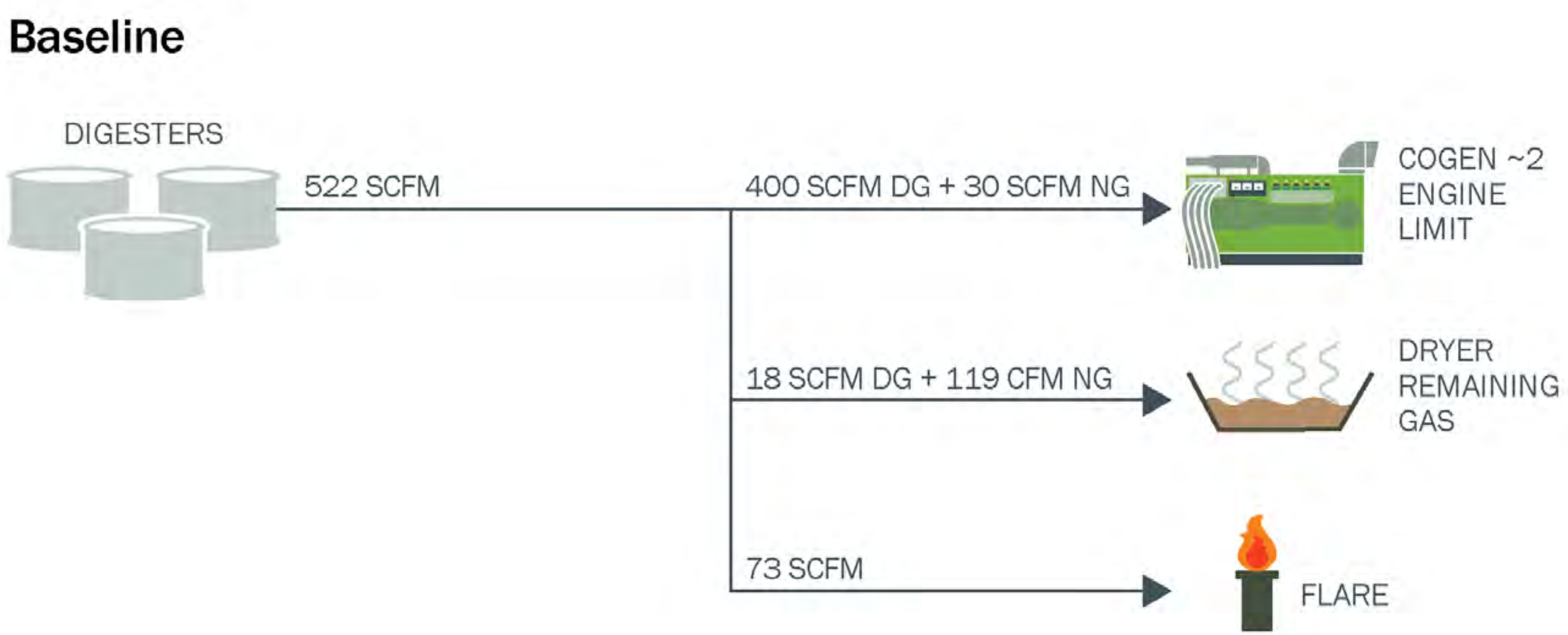
- Meso plus second dryer
- Meso plus Class B hauling
- Thermophilic
  - With and without second dryer
- Cambi (traditional)
  - With and without second dryer

- Additional Layers
  - Thickening
  - Dewatering
  - Energy alternatives
  - End use markets

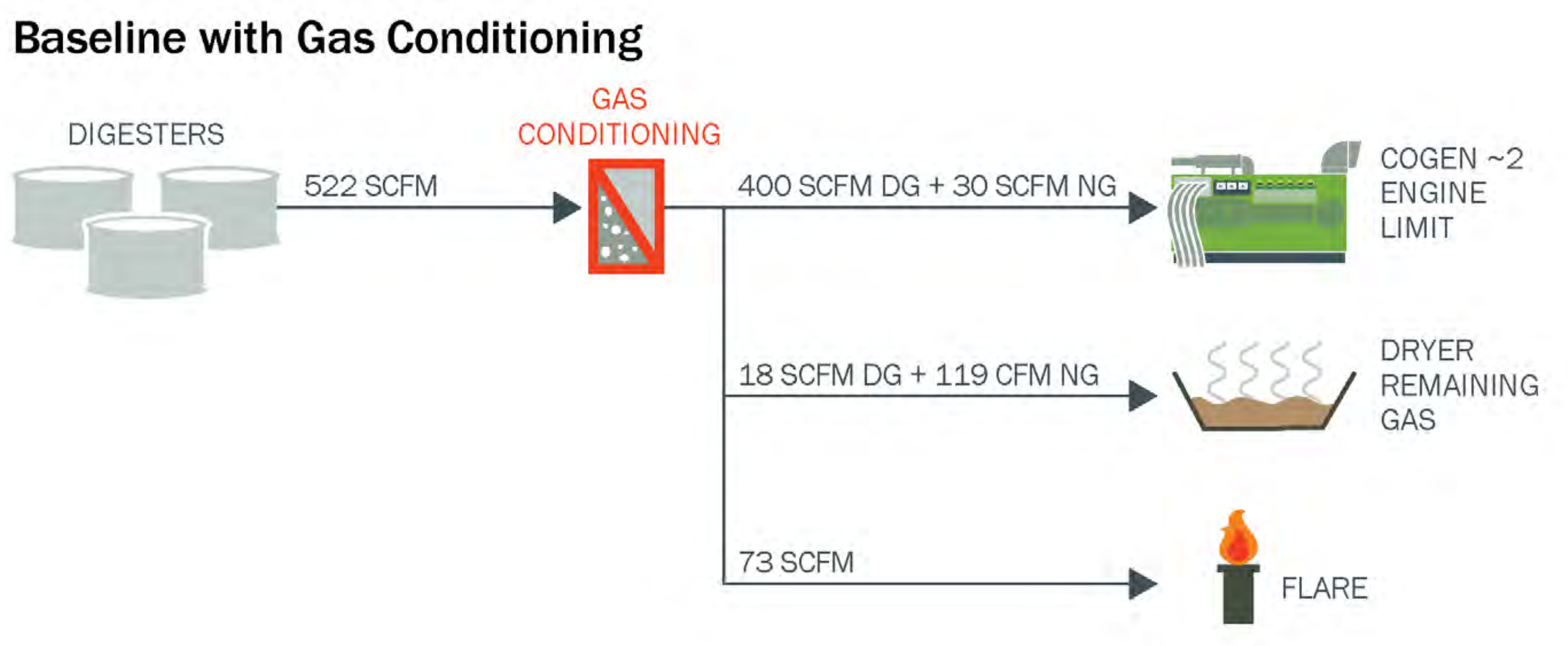
Alternatives: Power Production

- Baseline: Existing cogen + drying
- Baseline + gas conditioning
  - Gas conditioning serves to reduce O&M costs associated with engines and dryer
- Existing cogen + vehicle fuel (via pipeline injection or tube trailer)
  - No permit modification to cogen / no DG to dryer
  - Continue to operate two engines
  - Additional gas routed to vehicle fuel
- Existing cogen + microturbines
  - Includes gas conditioning
  - No permit modification to cogen / no DG to dryer
- Existing cogen + steam boiler/turbine
  - No permit modification to cogen / no DG to dryer
  - Additional gas routed to steam boiler; steam used in small turbine
- New cogen permit, CO catalyst and SCR, gas conditioning
  - Need to consider plant demand as a limit on power production
- Vehicle Fuel (primary use of DG) + existing cogen (natural gas + tail gas)
  - "All in" on vehicle fuel

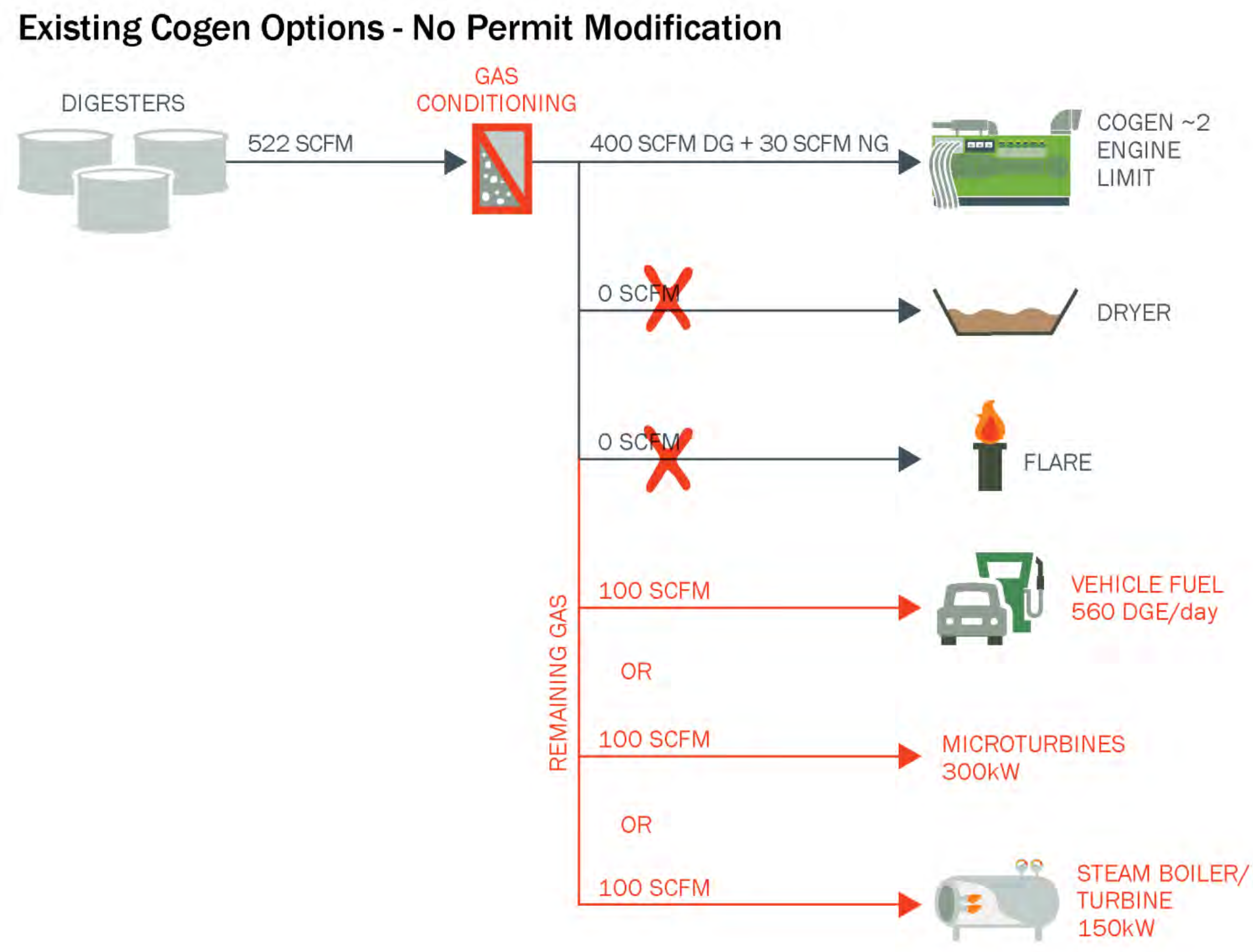
Baseline includes cogeneration (permit limited), dryer and some flaring



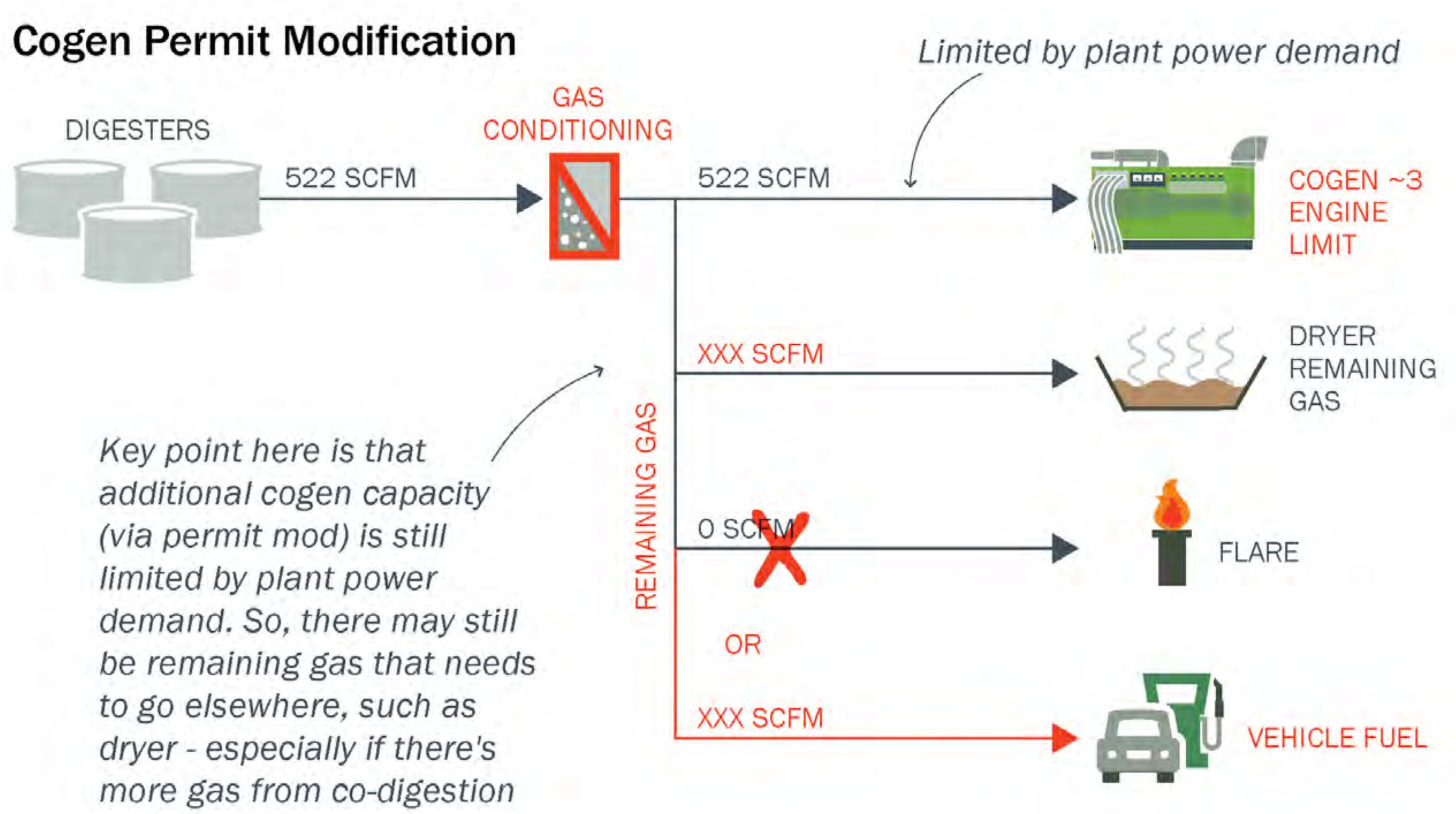
Gas conditioning could reduce engine and dryer O&M costs associated with siloxanes



With the existing permit in place, where else can we send digester gas to get highest value?

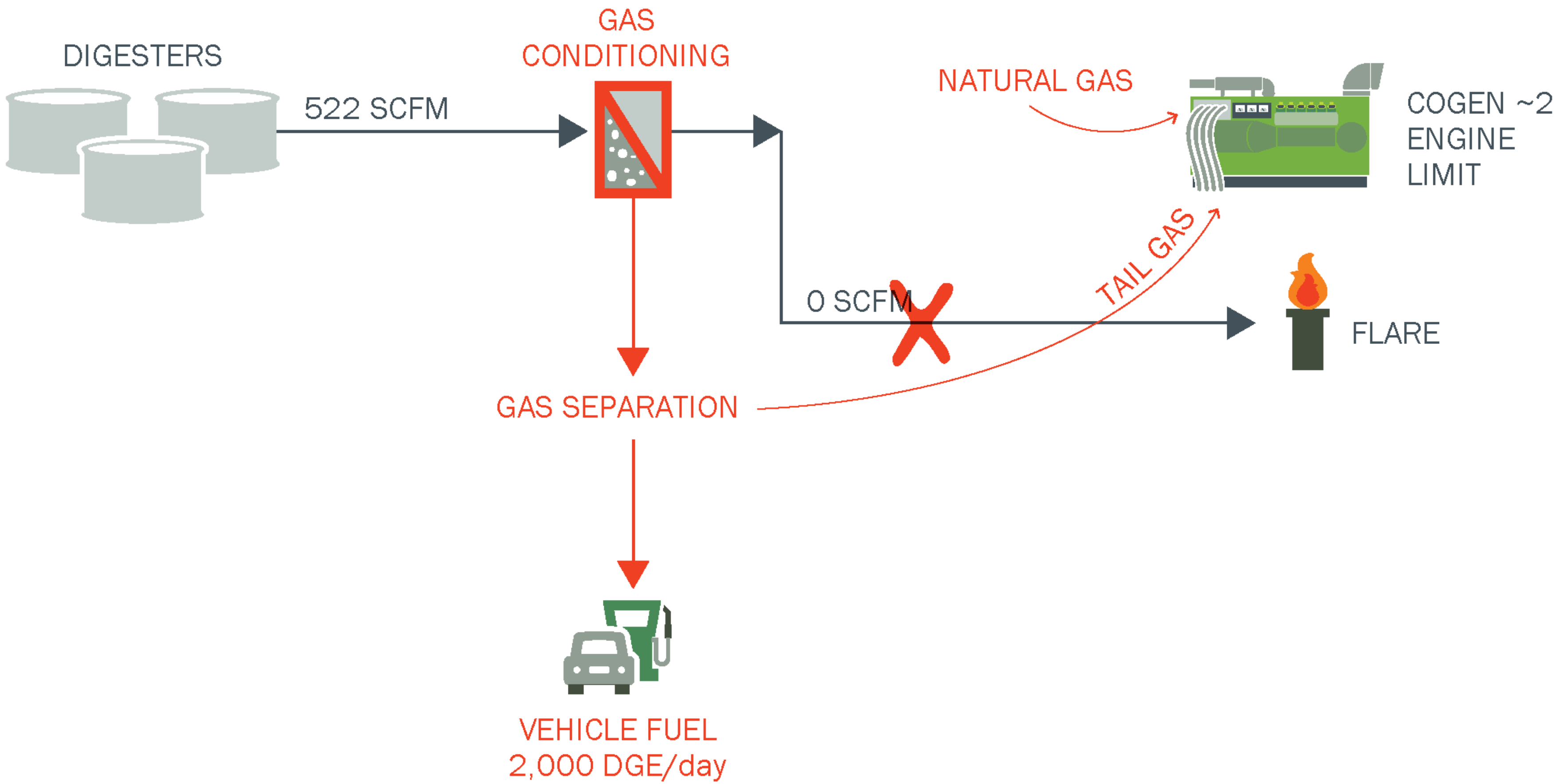


A permit modification allows EWA to meet plant electricity demand, but any additional gas would need to go to a non-generating use



An all-vehicle-fuel option may deliver the best economics

Vehicle Fuel



Alternatives to be presented at next workshop

- Process schematic
- General overview (pros and cons)
- Footprint
- Potential locations

Grant Updates

Self Generation Incentive Program

Program	Self-Generation Incentive Program (SGIP)
Agency	California Energy Commission / administered by SDG&E
Eligible Projects	Self-generation projects such as new engines, microturbines, or steam turbines – increased incentives for renewable/biogas projects; Energy storage / batteries
Funding	Incentives based on anticipated power output – based on fuel availability, not nameplate capacity; 50% paid upfront / 50% paid over 5 years based on performance
Schedule	Funding available each year / first-come, first-served Battery funding decreases as tiers fill up Projects must be operational within 18 months of award
How much are we talking?	~$500k - $1M depending on project size
Recommendation for SWEET Analysis	Don't count on funding to justify project economics
Next steps	Continue to track / pursue if selected alternatives meet criteria

Low-Carbon Fuel Standard

Program	Low-Carbon Fuel Standard (LCFS)
Agency	California Air Resources Board
Eligible Projects	Part of AB 32 scoping plan – projects that reduce the carbon intensity of California's vehicle fuel – i.e. renewable compressed natural gas (CNG vehicle fuel)
Funding	Incentives based on fuel production, market-based values; Paid on a per-gallon basis as the project performs
Schedule	Ongoing program, recently extended through 2030
How much are we talking?	Varies … could equate to ~\$0.50/DGE - \$1.00/DGE depending on market factors
Recommendation for SWEET Analysis	Include in SWEET analysis for vehicle fuel projects; Assume funding only through 2030, use conservative values
Next steps	Continue to track / pursue if vehicle fuel is recommended

Renewable Fuel Standard

Program	Renewable Fuel Standard
Agency	US Environmental Protection Agency
Eligible Projects	Renewable fuel projects– i.e. renewable compressed natural gas (CNG vehicle fuel)
Funding	Incentives based on fuel production, market-based values; Paid on a per-gallon basis as the project performs
Schedule	Ongoing program, not guaranteed beyond 2022
How much are we talking?	A lot of uncertainty: Wastewater digester gas is eligible for highest value of RINs – D3 EPA has recently stated that DG from food waste is a lower value – D5 EPA has the ability to set RIN quotas, which drive supply-and-demand, market-based pricing
Recommendation for SWEET Analysis	Include in SWEET analysis for vehicle fuel projects; Assume funding only through 2022, use conservative values
Next steps	Continue to track / pursue if vehicle fuel is recommended

Organics Grant Program

Program	Organics Grant Program
Agency	Department of Resource Recovery and Recycling (CalRecycle)
Eligible Projects	Projects that serve to divert organics (food waste) from landfill – toward anaerobic digestion or composting; recently issued with a food rescue requirement
Funding	Incentives based on project size and potential tons diverted
Schedule	Recently awarded, not expected to reissue for ~18 months
How much are we talking?	Up to $4M per project
Recommendation for SWEET Analysis	Do not include – too competitive to count on
Next steps	Continue to track / pursue if food waste receiving is recommended

Organics Grant Program - Recent Award

Recommendation:
Staff recommends approval of 10 grant awards, as listed in Table 1 below, for $24,000,000.

Table 1. Organics Grant Program Recommended Award – List A

Applicant	County	Total Award
Anaerobic Digestion Projects		
County Sanitation Districts of Los Angeles County	Los Angeles	$4,000,000
HZIU Kompogas SLO, Inc.	San Luis Obispo	$4,000,000
Rialto Bioenergy Facility, LLC	San Bernardino	$4,000,000
	Subtotal	**$12,000,000**
Compost Projects		
City of San Diego	San Diego	$3,000,000
Mid Valley Recycling, LLC	Fresno	$1,875,000
Salinas Valley Solid Waste Authority	Monterey	$1,341,865
Recology Yuba-Sutter *(partially funded)*	Yuba	$2,783,135
	Subtotal	**$9,000,000**
Rural Compost Projects		
Napa Recycling & Waste Services, LLC	Napa	$541,700
South Lake Refuse Company, LLC	Lake	$1,218,026
West Coast Waste *(partially funded)*	Madera	$1,240,274
	Subtotal	**$3,000,000**
	Grand Total	**$24,000,000**

Organics Grant Program - Recent Award

Table 2. Organics Grant Program Recommended Award – List B

Applicant	County	Total Award Requested*
Anaerobic Digestion Projects		
CR&R Incorporated	Riverside	$4,000,000
Contra Costa Waste Services	Contra Costa	$4,000,000
City of Manteca	San Joaquin	$1,500,000
Santa Barbara County	Santa Barbara	$4,000,000
Subtotal		**$13,500,000**
Compost Projects		
Recology Yuba-Sutter *(partially funded)*	Yuba	$216,865
Agromin OC, LLC	San Bernardino	$600,000
Waste Management of Alameda County, Inc.	Alameda	$3,000,000
GreenWaste Recovery, Inc.	Santa Clara	$1,700,000
Burrtec Waste Industries, Inc.	Riverside	$3,000,000
Arakelian Enterprises Inc. DBA Athens Services	San Bernardino	$3,000,000
Best Way Disposal Company, Inc. DBA Advance Disposal Co.	San Bernardino	$2,481,250
Kern County	Kern	$3,000,000
City of Oceanside	San Diego	$1,178,351
Subtotal		**$18,176,466**
Rural Compost Projects		
West Coast Waste *(partially funded)*	Madera	$161,326
Upper Valley Disposal Service	Napa	$1,250,000
Subtotal		**$1,411,326**
	Grand Total	**$33,087,792**

Heathy Soils Program

Program	Healthy Soils Program
Agency	California Department of Food and Agriculture
Eligible Projects	Demonstration projects that sequester carbon and reduce GHG emissions – groups within CASA
Funding	Incentives based on project size and potential GHG benefit
Schedule	Currently accepting applications through September 19 Annual funding program (AB 32 funds), amounts and criteria may vary
How much are we talking?	Up to $3.75M total
Recommendation for SWEET Analysis	Do not include / ancillary benefit to support end use program
Next steps	Continue to track / connect with CASA Science and Research Group for potential partnerships

Green Project Reserve

Program	Green Project Reserve
Agency	California Water Resources Control Board
Eligible Projects	Projects that improve energy efficiency, renewable energy generation, or recycled water production
Funding	A component of Clean Water State Revolving Funding; Green Project Reserve is a “loan forgiveness” program CWSRF is generally oversubscribed, but GPR is underutilized
Schedule	Ongoing
How much are we talking?	Up to $4M per project, or 50% of project value, whichever is higher
Recommendation for SWEET Analysis	Do not include
Next steps	Something for EWA to keep in mind – if a larger capital project requires funding, consider CWSRF and adding an eligible GPR component

Air Permitting Discussion

Brown AND Caldwell

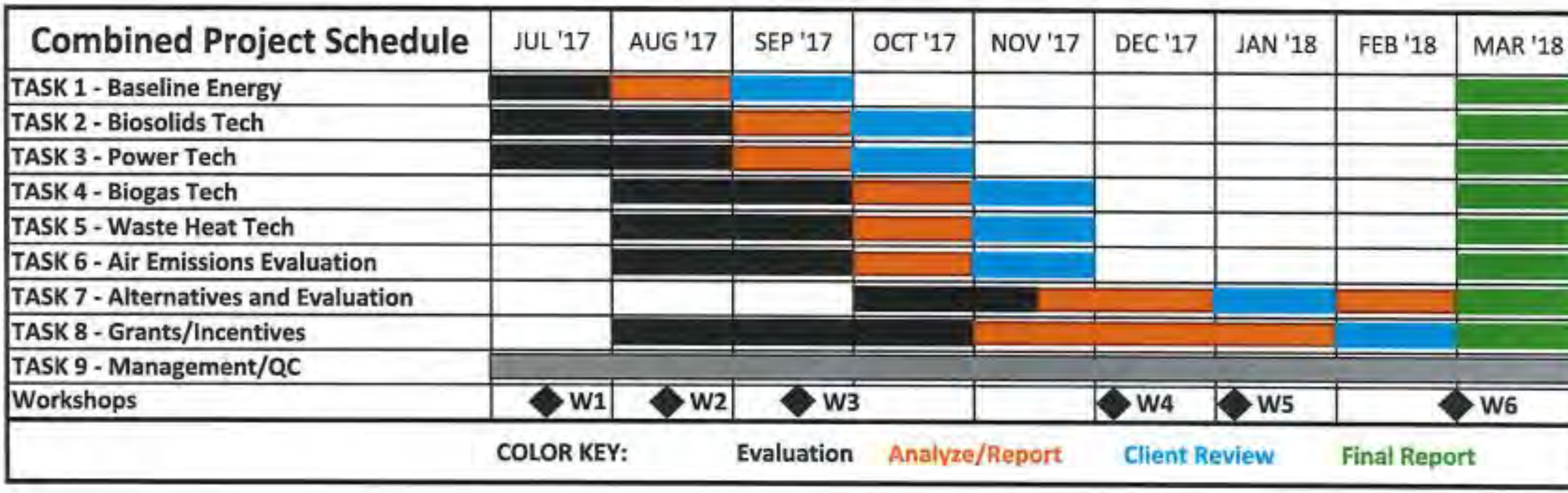
EWA is actively pursuing air permit modification

- EWA (with Don King) will submit a request for permit modification within ~1 week
- Goal is to adjust the CO emission rate from 530 ppm to ~400 ppm, and thereby adjust the fuel input limit aimed at keeping CO emissions below Title V synthetic minor threshold
- If successful, this effort would increase permitted cogen capacity by ~20%
- This increase would allow EWA to meet plant electricity demand with current digester gas flows and cogen system

Look Ahead & Wrap-Up

Project Schedule

- Workshop #3 in mid-September
- Draft Analysis and Reports to Begin



Look Ahead – September Workshop

- Consensus on mass balance/baseline
- Conceptual layouts/details of alternatives for consensus/feedback (example numbers to support including biogas production, food waste that can be imported)
- Air permitting impacts on power production alternatives
- Informational meeting with waste haulers
- Debrief on Anaergia meeting
- Grants update

Wrap-Up

QUESTIONS?

it's about connecting

Brown AND Caldwell : essential ingredients®

Attachment B: SDG&E Distribution Interconnection Handbook and BEE - Electrical Upgrades Required for Rule 21 Interconnection

SDG&E Electric Distribution System Interconnection Handbook

<Revised as of 10/21/2015>

A Sempra Energy utility®

TABLE OF CONTENTS

1 Introduction

1.1 *Purposes*

This handbook has been prepared to provide an overview of the technical requirements to interconnect Generating Facilities (includes all generators located at an interconnection point) to operate in parallel with SDG&E's distribution system. The requirements are necessary to ensure safe and reliable operation of SDG&E's electric system. The handbook shall serve as a guideline to SDG&E personnel and customer generation owners in completing generation to distribution interconnections that conform to SDG&E reliability requirements.

The interconnections include facility additions and modifications on generation and distribution systems necessary to accommodate the interconnection of generation to SDG&E distribution system. For generation interconnection to the transmission system, refer to ***SDG&E Generation Interconnection Handbook,*** which can be found on the SDG&E website, link below.

http://www.sdge.com/generation-interconnection-handbook

1.2 *Applicability and Related Tariffs*

All generators connected to the distribution system must meet the technical requirements of this handbook. The handbook is not intended to supersede

Interconnection Agreements required by SDG&E's Electric Rule 21 and/or the Wholesale Distribution Open Access Tariff (WDAT), particularly the Large Generator Interconnection Agreement (LGIA) and Small Generator Interconnection Agreement (SGIA).

1.3 *Interconnection Agreement Required*

The Owner/Operator must execute an Interconnection Agreement with SDG&E, and receive SDG&E's express written permission before parallel operation of its generating facility with SDG&E's Distribution System. SDG&E shall treat all requests in a non-discriminatory manner and shall not unreasonably withhold its permission for Parallel Operation of Owner/Operator's Generating Facility with SDG&E's Distribution System.

1.4 *Technical Requirement*

The technical requirements are organized in five (5) categories:

- Metering
- Protection and Control

- Operating Requirements
- Operating Procedures
- Energization and Synchronization

2 Metering Requirements

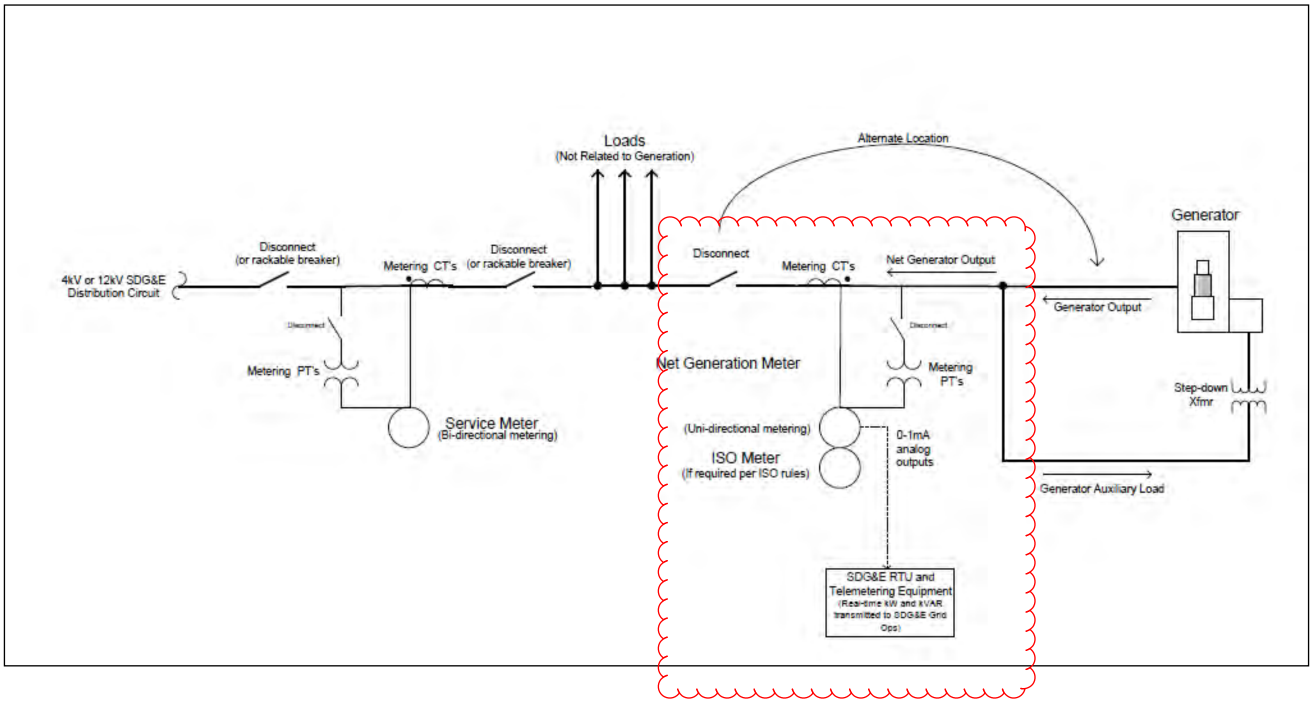
2.1 *Basic Metering Requirements*

- On generating facilities < 1 MW, it is recommended that SDG&E metering be installed to measure net generator output (generator output minus auxiliary loads associated with the generator) per SDG&E metering standards and requirements.
- On generating facilities >= 1MW, SDG&E metering shall be installed to measure net generator output (generator output minus auxiliary loads associated with the generator) in addition to SDG&E telemetering.
- SDG&E metering shall be installed to meter import and export at the SDG&E service point(s) regardless of Generating Facility size.
- If the facility is a generating facility serving only auxiliary load with one SDG&E service point, the SDG&E service point is also considered to be the net generator output point, so no additional net generation output meter is required or recommended.
- For a generating facility that requires CAISO (California Independent System Operator) metering, a CAISO meter(s) shall be installed at the SDG&E service point or at the net-generation point(s) per CAISO requirements and policies.

2.2 *Metering Equipment Layout*

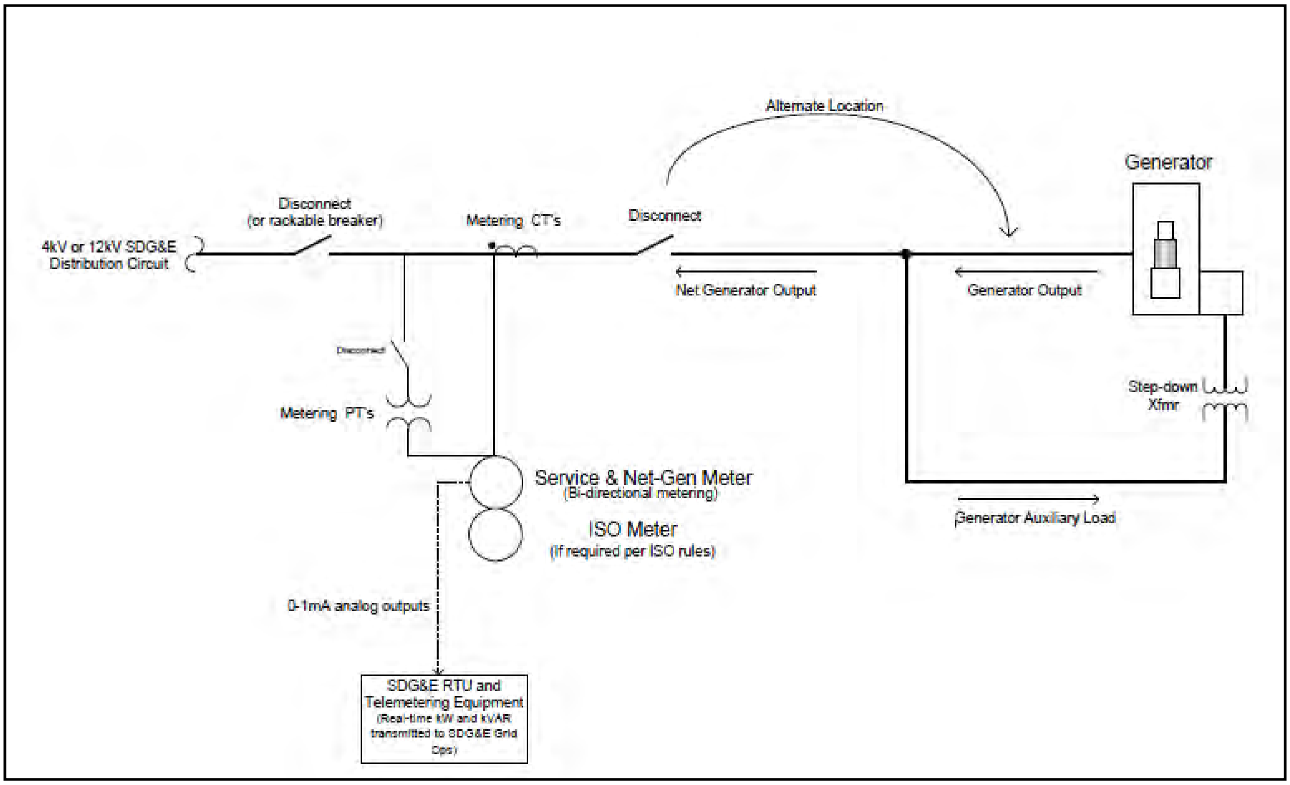
A typical metering layout of a generating facility containing load that is not directly associated with generation is illustrated in Figure 1.

Figure 1: Typical Generation Facility Metering Layout (w/ loads not related to generation)



A typical metering layout of a generating facility with only loads associated with generation is illustrated in Figure 2.

Figure 2: Typical Generation Facility Metering Layout (w/ <u>only</u> loads associated with generation)



2.3 *Metering Sections*

- At all points where SDG&E meters are to be installed, the Owner/Operator shall acquire and install a metering section. The metering section includes cable pull sections, bus bars for metering CT/PT insertion; disconnect switches, a metering panel, a meter socket(s), and accommodations for test switches/test blocks. Please refer to pages 676 and 677 of SDG&E's Electric Service Standards & Guide Manual for a typical metering section.
- Detailed information on all new proposed metering sections for the project shall be provided to SDG&E as part of the review and approval process described in the applicable tariff. This includes (but is not limited to) clearances from the metering section and details of the standing surface of the metering section.
- A set of disconnect switches or a rackable breaker shall be placed directly on the line side of each metering section as well as a set of disconnect switches for the metering PT's (accessible by SDG&E personnel only) per SDG&E service requirements. In addition, a set of disconnect switches shall be placed on the load side of the meter or at the point of generator output.
- Locations of these disconnect switches (or rackable breakers) are illustrated in Figures 1 and 2 above.
- The required disconnect switches (or rackable breakers) shall allow visible verification that separation has occurred.
- Disconnect switches are required to be gang operated.
- Disconnect switches and rack-out breakers must accommodate locking devices to allow SDG&E to lock-out services or net-generation points when necessary.
- Suitable locations shall be selected for all SDG&E metering sections per requirement outlined on page 602 of SDG&E's Electric Service Standards & Guide Manual.
- CAISO meters shall be located on the same metering panel plate as SDG&E meters that serve to meter the same point (e.g. net-generation point, SDG&E service point). Both meters will tap off the same metering PT's/CT's with the enclosure/panel having two sockets and test switches. See page 678 of SDG&E's Electric Service Standards & Guide Manual for a typical layout of this panel configuration.
- Any load that precedes point of service metering must be metered by an SDG&E self-contained meter on the same meter panel as that of the SDG&E meter. Typically, this load consists of customer owned PT's feeding control, protection, and monitoring devices. A typical panel layout showing this self-contained metering is shown on pages 679 and 680 of SDG&E's Electric Service Standards & Guide Manual.
- For self-contained meters, the Owner/Operator is required to acquire and install test blocks that meet SDG&E service requirements.

- The Electric Service Standards & Guide Manual can be found at:

  http://www.sdge.com/electric-service-standards-guide-manual

2.4 *Other Metering Requirements*

- An activated dial-up phone line shall be provided to each SDG&E meter.
- This phone line shall be routed to the associated meter panel with the SDG&E meter where SDG&E can plug an RJ-11 connector to obtain phone service to the meter. The RJ-11 connection point shall be within 12” of the meter socket.
- Monthly costs and maintenance of the phone lines to SDG&E meters are the responsibly of the Owner/Operator.
- At all SDG&E metering locations where voltage potential may be lost (except in the event of a planned or forced SDG&E outage), the Owner/Operator shall supply each SDG&E meter with a 120VAC uninterruptible power supply (UPS).
- A dedicated breaker position in the UPS breaker panel shall be utilized to supply each meter with UPS power and shall be clearly marked as feeding an SDG&E meter.
- The Owner/Operator may request KYZ outputs from any SDG&E meter for a one-time cost. See Figure 3 shown in Section 2.6 of this handbook for a typical KYZ output configuration.

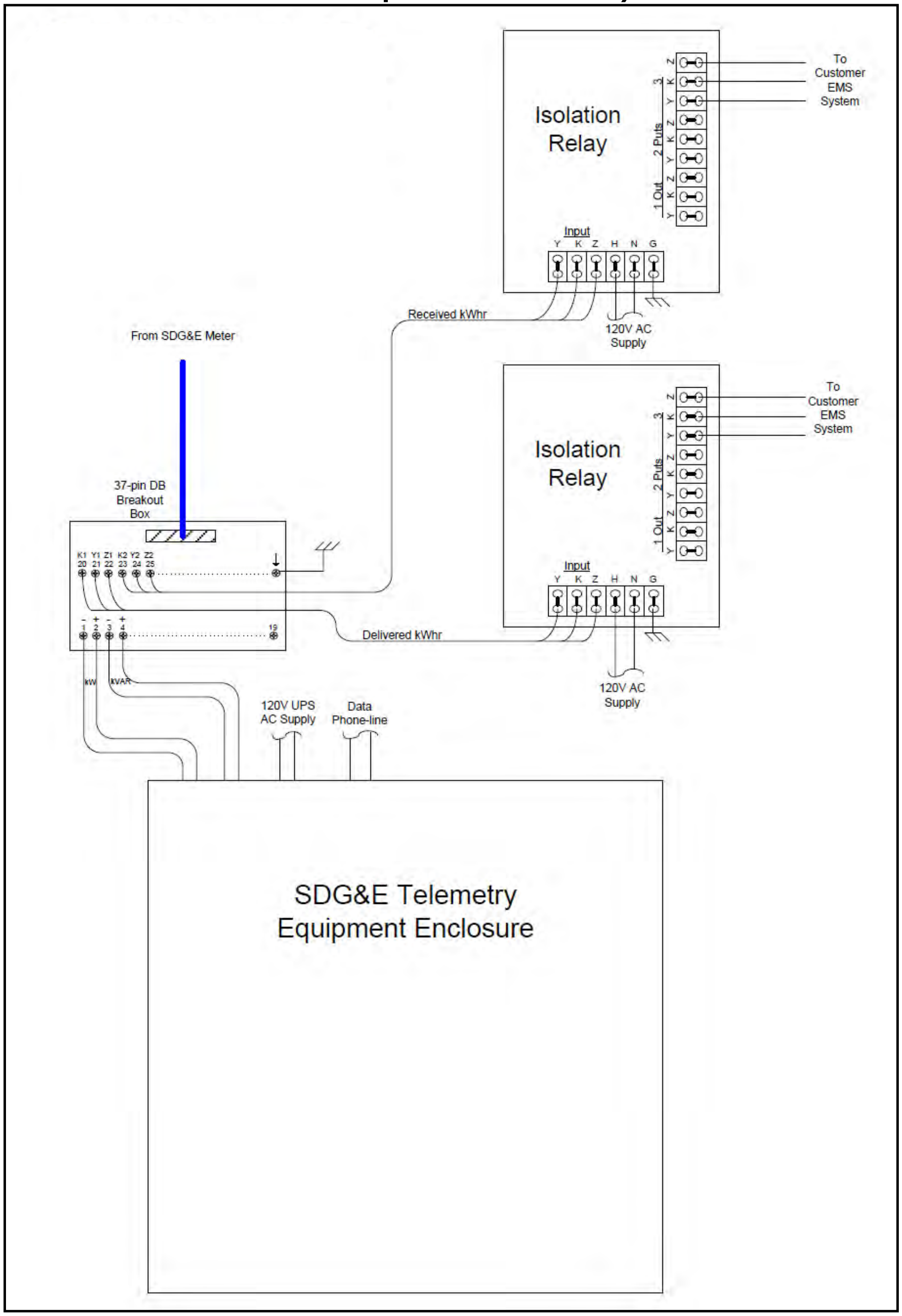
2.5 *Metering Equipment Installation*

- All metering sections shall be installed by the Owner/Operator.
- Upon final approval of the metering sections, layout, and overall facility, SDG&E personnel will provide, install and wire the metering CT’s/PT’s, telemetry equipment (if applicable), and test switches in preparation for the installation of SDG&E meters.
- If a CAISO meter is required, SDG&E will wire all CAISO metering. However, an ISO certified contractor is required to perform installs of CAISO meters per arrangements made by the Owner/Operator with the CAISO.

2.6 *Telemetering Equipment*

- SDG&E telemetering equipment located at net generation output metering points for generators >= 1MW utilize outputs from SDG&E meters located at the same metering points. See Figure 3 below for typical telemetering configuration.

Figure 3: Typical Telemetering Interface with SDG&E Metering (w/ KYZ outputs to customer)



- Telemetering requires a dedicated 120VAC UPS source. The telemetering equipment enclosure should be placed on or close to the meter panel but is not required to be on the meter panel. A suitable conduit can be used to interconnect the telemetering equipment with the SDG&E meter.
- The telemetering requires a high speed dedicated data line to SDG&E's Grid Operations center.
- Costs associated with the set-up requirements of telemetering equipment (e.g., conduit runs, activated data line) are borne by the Owner/Operator. There is a one-time cost to the Owner/Operator for the SDG&E telemetering equipment.

2.7 *Meter Reading/Maintenance/Testing*

- SDG&E will own, install, maintain, read, and test all SDG&E meters, telemetry equipment, metering PT's/CT's, and associated wiring installed at the facility.
- 24hr/7day unrestricted and unescorted access to all metering equipment and metering associated devices shall be provided to SDG&E metering personnel. All locked doors and gates SDG&E metering personnel must pass through to gain access shall each contain a SDG&E Schlage restricted VTQP quad lock supplied and installed by the Owner/Operator. A list of locksmiths authorized by SDG&E to sell Schlage restricted VTQP quad locks is listed on page 005.1 of SDG&E's Electric Service Standards & Guide Manual.
- If required, the Owner/Operator shall be responsible for installing, maintaining, reading, and testing the CAISO meter(s) per CAISO requirements. It is the responsibility of the facility Owner/Operator to comply with all applicable CAISO metering standards and requirements.
- Per SDG&E request, the Owner/Operator of the Generating Facility shall make all necessary arrangements with the CAISO for SDG&E to obtain all 5 min interval data reads from the CAISO meter. SDG&E will in-turn, upon reasonable notification, supply the CAISO with meter data from the SDG&E meter in the event of a CASIO meter failure within a reasonable time-frame, and with the understanding that most SDG&E meters only record IDR data on a 15min basis per SDG&E tariffs.
- The format of these reads must be compatible with SDG&E's meter reading system (MV90) using a Hand-Held Files (HHF) format. SDG&E shall supply the CAISO with meter data in this same HHF format.
- All metering sections and associated equipment are maintained by the Owner/Operator. In the event of a failure or malfunction of this equipment, the Owner/Operator is responsible for all replacements and repairs.
- The metering PT's/CT's, SDG&E meters, and SDG&E telemetry equipment is owned and therefore maintained by SDG&E.
- Repairs and replacements of CAISO meters are the Owner/Operator's responsibility and not the responsibility of SDG&E.

- Upon reasonable advanced notification by SDG&E, the Owner/Operator shall operate disconnect switches and/or rack-out breakers in order for SDG&E to perform maintenance on metering CT/PT's, telemetering equipment, or inspection of the metering section.
- Upon a failure or malfunction of a metering section or SDG&E equipment, the Owner/Operator shall accommodate immediate arrangements with SDG&E to operate disconnects or rack-out breakers.

3 Protection and Control Requirements

3.1 *Purpose*

This section specifies the requirements for protection and control devices for Generating Facilities interconnecting to the SDG&E Distribution System.

The applicable protective standards of this section apply to all Generating Facilities interconnecting to any portion of SDG&E's Distribution System. These standards, which govern the design, construction, inspection and testing of protective devices, have been developed to be consistent with SDG&E's Rule 21, *Interconnection Standards for Non-Utility Owned Generation*, and IEEE 1547, *IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems*.

3.2 *General Interconnection and Protective Function Requirements*

The Protective Functions and requirements of this Section are designed to protect SDG&E's Distribution System and not the Generating Facility. An Owner/Operator shall be solely responsible for providing adequate protection for its Generating Facility and Interconnection Facilities. The Owner/Operator's protective equipment shall not impact the operation of other protective equipment utilized on SDG&E's Distribution System in a manner that would affect SDG&E's capability of providing reliable service to its Customers.

Protective Equipment Required - Generating Facilities operating in parallel with SDG&E's Distribution System shall be equipped with protective devices that will sense abnormal conditions on SDG&E's Distribution System and will: cause the Generating Facility to automatically disconnect from SDG&E's Distribution System, or will prevent the Generating Facility from being connected to SDG&E's Distribution System inappropriately. These protective functions include:

1) Over and under voltage trip functions and over and under frequency trip functions;

2) A voltage and frequency sensing and time-delay function that will prevent the Generating Facility from energizing a de-energized Distribution System circuit, and will prevent the Generating Facility from reconnecting with SDG&E's Distribution System unless SDG&E's Distribution System service voltage and frequency is: a) within the ANSI C84.1-1995 Table 1 Range B Voltage Range of 106V to 127V (on a 120V basis), inclusive, and b) within a frequency range of 59.7 Hz to 60.5 Hz inclusive, and is stable for at least 60 seconds.

3) A function to prevent the Generating Facility from contributing to the formation of an Unintended Island, and cease to energize SDG&E's Distribution System within two seconds of the formation of an Unintended Island.

The Generating Facility shall cease to energize SDG&E's Distribution System for faults on SDG&E's Distribution System circuit to which it is connected (IEEE1547-4.2.1). The Generating Facility shall cease to energize SDG&E's Distribution circuit prior to reclosure by SDG&E's Distribution System equipment (IEEE1547-4.2.2).

Momentary Paralleling Generating Facilities - With SDG&E's approval, the transfer switch or scheme used to transfer the Owner/Operator's loads from SDG&E's Distribution System to Owner/Operator's Generating Facility may be used in lieu of the protective functions required for Parallel Operation.

Suitable Equipment Required - Circuit breakers or other interrupting equipment located at the Point of Common Coupling (PCC) must be Certified or "Listed" (as defined in Article 100, the Definitions Section of the National Electrical Code) as suitable for their intended application. This includes being capable of interrupting the maximum available fault current expected at their location. Owner/Operator's Generating Facility and Interconnection Facilities shall be designed so that the failure of any single device or component shall not potentially compromise the safety and reliability of SDG&E's Distribution System. The Generating Facility paralleling-device shall be capable of withstanding 220% of the Interconnection Facility rated voltage (IEEE1547-4.1.8.3). The Interconnection Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Std C62.41.2-2002 or IEEE Std C37.90.1-2002 as applicable and as described in Rule 21 Section J.3.e (IEEE1547-4.1.8.2).

Visible Disconnect Required - When required by SDG&E's operating practices, the Owner/Operator shall furnish and install a ganged, manually-operated isolating switch (or a comparable device mutually agreed upon by SDG&E and the Owner/Operator) near the Point of Interconnection to isolate the Generating Facility from SDG&E's Distribution System. The device does not have to be rated for load break nor provide over-current protection. The device must:

1) Allow visible verification that separation has been accomplished. (This requirement may be met by opening the enclosure to observe contact separation.)

2) Include markings or signage that clearly indicates open and closed positions.

3) Be capable of being reached quickly and conveniently 24 hours a day by SDG&E personnel for construction, operation, maintenance, inspection, and testing or reading without: a) obstacles, b) a requirement to seek access to climb over or remove obstacles, or c) a requirement to obtain keys, special permission, or security clearances.

4) Be capable of being locked in the open position.

5) Be clearly marked on the submitted single line diagram and its type and location approved by SDG&E prior to installation. If the device is not

adjacent to the PCC, permanent signage must be installed at an SDG&E approved location providing a clear description of the location of the device.

Generating Facilities with Non-Islanding inverters totaling one (1) kilovolt-ampere (kVA) or less are exempt from this requirement.

Drawings Required - Prior to Parallel Operation or Momentary Parallel Operation of the Generating Facility, SDG&E shall approve the Owner/Operator's protective function and control diagrams. Generating Facilities equipped with protective functions and a control scheme previously approved by SDG&E for system-wide application or only Certified Equipment may satisfy this requirement by reference to previously approved drawings and diagrams.

3.3 *Prevention of Interference*

The Owner/Operator shall not operate Generating or Interconnection Facilities that superimpose a voltage or current upon SDG&E's Distribution System, or that interferes with SDG&E operations, service to SDG&E customers, or communication facilities. If such interference occurs, the Owner/Operator must diligently pursue and take corrective action at its own expense after being given notice and reasonable time to do so by SDG&E. If the Owner/Operator does not take corrective action in a timely manner, or continues to operate the facilities causing interference without restriction or limit, SDG&E may, without liability, disconnect the Owner/Operator's facilities from SDG&E's Distribution System, in accordance with Section 3.4 of the Wholesale Open Access Distribution Tariff Small Generator Interconnection Agreement (WDAT SGIA). Below is a link to the WDAT SGIA:

http://www.sdge.com/generation-interconnections/wholesale-generator-transmission-interconnections

To eliminate undesirable interference caused by its operation, each Generating Facility (GF) shall meet the following criteria:

Voltage Regulation - The GF shall not actively regulate the voltage at the PCC while in parallel with SDG&E's Distribution System. The GF shall not cause the service voltage at other customers to go outside the requirements of ANSI C84.1-1995, Range A (IEEE1547-4.1.1).

Operating Voltage Range - The voltage ranges in Table 1 below define protective trip limits for the protective function and are not intended to define or imply a voltage regulation function. Generating Facilities shall cease to energize SDG&E's Distribution System within the prescribed trip time whenever the voltage at the PCC deviates from the allowable voltage operating range. The protective function shall detect and respond to voltage on all phases to which the Generating Facility is connected.

1) **Generating Facilities (30 kVA or less**) - Generating Facilities with a Gross Nameplate Rating of 30 kVA or less shall be capable of operating within the

voltage range normally experienced on SDG&E's Distribution System from 114V to 126V on a 120V base, at the service panel or PCC. The trip settings at the generator terminals may be selected in a manner that minimizes nuisance tripping between 106 volts and 132 volts on a 120-volt base (88%-110% of nominal voltage) to compensate for voltage drop between the generator terminals and the PCC. Voltage may be detected at either the PCC or the Point of Interconnection. However, the normal operating voltage range at the PCC, with the generator on-line, shall stay within +/- 5% of nominal voltage.

2) **Generating Facilities (greater than 30 kVA) -** SDG&E may have specific operating voltage ranges for Generating Facilities with Gross Nameplate Ratings greater than 30 kVA, and may require adjustable operating voltage settings. In the absence of such requirements, the Generating Facility shall operate at a range between 88% and 110% of the applicable interconnection voltage. Voltage shall be detected at either the PCC or the Point of Interconnection, with settings compensated to account for the voltage at the PCC. However, the normal operating voltage range at the PCC, with the generator on-line, shall stay within +/- 5% of nominal voltage.

3) **Voltage Disturbances -** Whenever SDG&E's Distribution System voltage at the Point of Common Coupling varies from and remains outside normal (nominally 120 volts) by the predetermined amounts set forth in Table 1, the Generating Facility's protective functions shall cause the Generator(s) to become isolated from SDG&E's Distribution System.

Table 1: Voltage Trip Settings

Voltage at Generator Terminal or Point of Common Coupling (the ranges below are used to trip the generator during abnormal conditions)		Maximum Trip Time *[1]*	
Assuming 120 V Base	% of Nominal Voltage	# of Cycles (Assuming 60Hz Nominal)	Seconds
Less than 60 Volts	Less than 50%	10 Cycles	0.16 Seconds
Greater than or equal to 60 Volts but less than 106 Volts	Greater than or equal to 50% but less than 88%	120 Cycles	2 Seconds
Greater than 132 Volts but less than or equal to 144 Volts	Greater than 110% but less than or equal to 120%	60 Cycles	1 Second
Greater than 144 Volts	Greater than 120%	10 Cycles	0.16 Seconds

[1] -"Maximum Trip time" refers to the time between the onset of the abnormal condition and the Generating Facility ceasing to energize SDG&E's Distribution System. Protective function sensing equipment and circuits may remain connected to SDG&E's Distribution System to allow sensing of electrical conditions for use by the "reconnect" feature. The purpose of the allowed time delay is to allow a Generating Facility to "ride through" short-term disturbances to avoid nuisance tripping. Set

points shall not be user adjustable (though they may be field adjustable by qualified personnel). For Generating Facilities with a Gross Nameplate Rating greater than 30 kVA, set points shall be field adjustable and different voltage set points and trip times from those in Table 1 may be negotiated with SDG&E.

Paralleling - The Generating Facility shall parallel with SDG&E's Distribution System without causing a voltage fluctuation at the PCC greater than ±5% of the prevailing voltage level of SDG&E's Distribution System, and meet the flicker requirements of this section. (IEEE1547-4.1.3)

Flicker - The Generating Facility shall not create objectionable flicker for other customers on SDG&E's Distribution System. To minimize the adverse voltage effects experienced by other customers (IEEE1547-4.3.2), flicker at the Point of Common Coupling caused by the Generating Facility should not exceed the limits defined by the "Maximum Borderline of Irritation Curve" identified in IEEE 519-1992 (IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems, IEEE STD 519-1992, Institute of Electrical and Electronic Engineers, Piscataway, NJ). This requirement is necessary to minimize the adverse voltage affects experienced by other customers on SDG&E's Distribution System. Generators may be connected and brought up to synchronous speed (as an induction motor) provided these flicker limits are not exceeded.

Integration with SDG&E's Distribution System Grounding - The grounding scheme of the Generating Facility interconnection shall not cause overvoltages that exceed the rating of the equipment connected to SDG&E's Distribution System, and shall not disrupt the coordination of the ground fault protection on the SDG&E's Distribution System (IEEE1547-4.1.2) (See Section I.3.h). The gas standard must be followed where electrical equipment is in the vicinity of the gas meter assembly. Any electrical connection to SDG&E's gas equipment is a violation of the Code and is unsafe. Electric bonding to SDG&E's gas service pipes, gas riser, or gas meter assembly is not permitted (Gas Standard page 1003).

Frequency - SDG&E controls system frequency, and the Generating Facility shall operate in synchronism with the SDG&E's Distribution System. Whenever SDG&E's Distribution System frequency at the Point of Common Coupling varies from and remains outside normal (nominally 60 Hz) by the predetermined amounts set forth in Table 2 below, the Generating Facility's protective functions shall cease to energize SDG&E's Distribution System within the stated maximum trip time.

Table 2: Frequency Trip Settings

<table>
<tr><th>Generating Facility Rating:</th><th>Frequency Rating
(60Hz Nominal)</th><th>Maximum Trip Time [1]
(Assuming 60 Cycles per Second)</th></tr>
<tr><td rowspan="2">Less or equal to 30kW</td><td>Less than 59.3 Hz</td><td>10 Cycles</td></tr>
<tr><td>Greater than 60.5 Hz</td><td>10 Cycles</td></tr>
<tr><td rowspan="3">Greater than 30kW</td><td>Less than 57.0 Hz</td><td>10 cycles</td></tr>
<tr><td>Less than an adjustable value between 59.8 Hz and 57 Hz but greater than 57 Hz. [2]</td><td>Adjustable between 10 and 18,000 Cycles. [2, 3]</td></tr>
<tr><td>Greater than 60.5 Hz</td><td>10 Cycles</td></tr>
</table>

[1] -"Maximum Trip time" refers to the time between the onset of the abnormal condition and the Generating Facility ceasing to energize SDG&E's Distribution System. Protective function sensing equipment and circuits may remain connected to SDG&E's Distribution System to allow sensing of electrical conditions for use by the "reconnect" feature. The purpose of the allowed time delay is to allow a Generating Facility to "ride through" short-term disturbances to avoid nuisance tripping. Set points shall not be user adjustable (though they may be field adjustable by qualified personnel). For Generating Facilities with a Gross Nameplate Rating greater than 30 kVA, set points shall be field adjustable and different voltage set points and trip times from those in Table 2 may be negotiated with SDG&E.

[2] - Unless otherwise required by SDG&E, a trip frequency of 59.3 Hz and a maximum trip time of 10 cycles shall be used.

[3] - When a 10 cycle Maximum trip time is used, a second under frequency trip setting is not required.

Harmonics - When the Generating Facility is serving balanced linear loads, harmonic current injection into SDG&E's Distribution System at the PCC shall not exceed the limits stated below in Table 3 below. The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in SDG&E's Distribution System without the Generating Facility connected (IEEE1547-4.3.3). The harmonic distortion of a Generating Facility located at a Customer's site shall be evaluated using the same criteria as for the Host Loads.

Table 3: Maximum harmonic current distortion in percent of current (I) *[1,2]*

Individual harmonic order, h (odd harmonics) *[1]*	h < 11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h	Total demand distortion (TDD)
Max Distortion (%)	4.0	2.0	1.5	0.6	0.3	5.0

[1] - Even harmonics are limited to 25% of the odd harmonic limits above.

Direct Current Injection - Generating Facilities should not inject direct current greater than 0.5% of rated output current into SDG&E's Distribution System.

Power Factor - Each Generator in a Generating Facility shall be capable of operating at some point within a power factor range from 0.90 leading to 0.90 lagging. Operation outside this range is acceptable provided the reactive power of the Generating Facility is used to meet the reactive power needs of the Host Loads, or that reactive power is otherwise provided under tariff by SDG&E. The Owner/Operator shall notify SDG&E if it is using the Generating Facility for power factor correction. Unless otherwise agreed upon by the Owner/Operator and SDG&E, Generating Facilities shall automatically regulate power factor, not voltage, while operating in parallel with SDG&E's Distribution System.

3.4 *Technology Specific Requirements*

Three-Phase Synchronous Generators - For three-phase Generators, the Generating Facility circuit breakers shall be three-phase devices with electronic or electromechanical control. The Owner/Operator shall be responsible for properly synchronizing its Generating Facility with SDG&E's Distribution System by means of either manual or automatic synchronizing equipment. Automatic synchronizing is required for all synchronous Generators that have a Short Circuit Contribution Ratio (SCCR) exceeding 0.05. Loss of synchronism protection is not required except as may be necessary to meet flicker requirements (IEEE1547-4.2.5). Unless otherwise agreed upon by the Owner/Operator and SDG&E, synchronous Generators shall automatically regulate power factor, not voltage, while operating in parallel with SDG&E's Distribution System. A power system stabilization function is specifically not required for Generating Facilities under 10 MW Net Nameplate Rating.

Induction Generators - Induction Generators (except self-excited Induction Generators) do not require a synchronizing function. Starting or rapid load fluctuations on induction generators can adversely impact SDG&E's Distribution System's voltage. Corrective step-switched capacitors or other techniques may be necessary and may cause undesirable ferro-resonance. When these counter measures (e.g., additional capacitors) are installed on the Owner/Operator's side of the Point of Common Coupling, SDG&E must review these measures. Additional equipment may be required as determined in an interconnection review or an Interconnection Study.

Inverters - Utility-interactive inverters do not require separate synchronizing equipment. Non-utility-interactive or "stand-alone" inverters shall not be used for Parallel Operation with SDG&E's Distribution System.

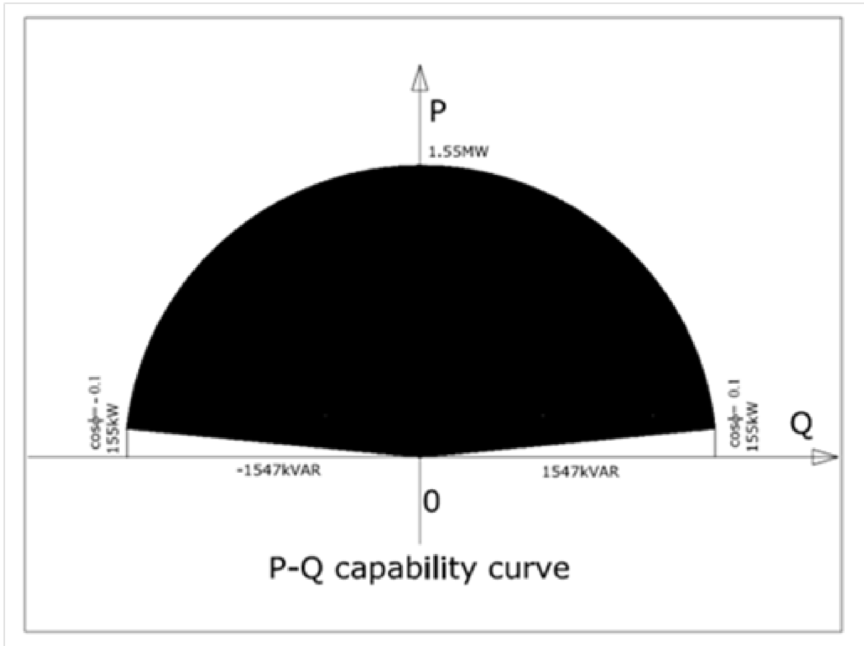
Single-Phase Generators - For single-phase Generators connected to a shared single-phase secondary system, the maximum Net Nameplate Rating of the Generating Facilities shall be 20 kVA. Generators connected to a center-tapped neutral 240-volt service must be installed such that no more than 6 kVA of imbalanced power is applied to the two "legs" of the 240-volt service. For Dedicated Distribution Transformer services, the maximum Net Nameplate Rating of a single-phase Generating Facility shall be the transformer nameplate rating.

3.5 *Inverter Specifications*

Reactive Power - The inverter shall be capable of operating in the following reactive power modes:

- Dynamic power factor: Inverter shall be capable of operating dynamically at a minimum power factor range of +/- .85 PF for larger systems (>15 kW), +/- 0.90 PF for smaller systems (≤15 kW), and a preferred power factor range of +/- 0.10 PF. Figure 4 below illustrates the preferred power factor range of +/- 0.10 PF.

Figure 4: P-Q Capability Curve

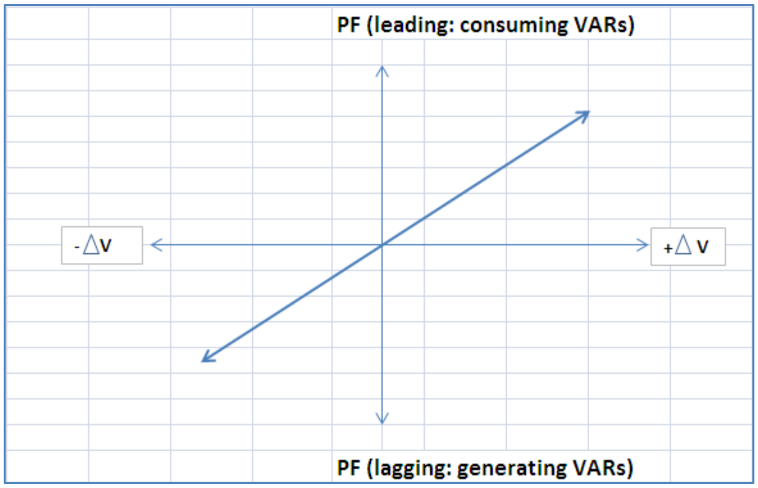


- Dynamic VAR output or input:
  - Inverter shall autonomously prevent line voltage changes from exceeding 2% at the point of common coupling (PCC) due to a loss of generation, or due to an increase in generation output. Inverter output shall not cause the line voltage at the point of common coupling to go outside the requirements of the latest version of ANSI C84.1, Range A.
  - Dynamic VAR output/input function shall not operate within a total deadband of 2% (i.e. a range of +/-1%) of line voltage at the PCC.
- Autonomous operations described above may be superseded by an external signal issued by distribution system operator.

The reactive power output of the inverter must be dynamic and adjustable. It must be possible to provide the prescribed reactive power compensation within the following time constraints:

- Within 10 seconds if reactive power setting is prescribed by autonomous control
- Within 5 seconds if reactive power setting is prescribed by external signal which will supersede autonomous settings.
- No change in reactive compensation shall occur unless the voltage changes outside the deadband range of 2% (+/-1%)

The inverter shall consume reactive power in response to an increase in line voltage, and generate reactive power in response to a decrease in line voltage. An example of the desired correlation between reactive power output and changes in line voltage is shown below.

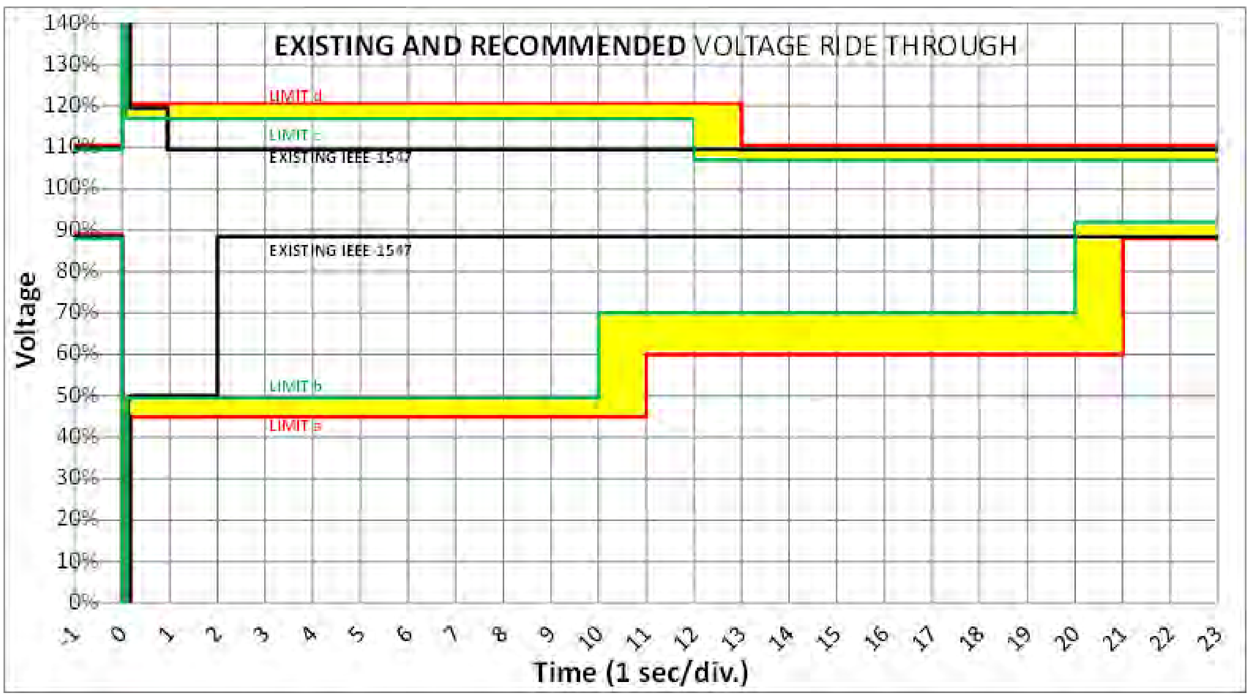


Low Voltage Ride-Through:

Inverters shall stay connected to the electric grid, and shall disconnect from the electric grid during a high or low voltage event, in compliance with the parameters shown in the following table and graph:

Table 4: Low Voltage Ride-Through Percent of Nominal

Voltage Level	Stay Connected Until		Voltage level	Disconnect by
>1.17	0.1 sec		>1.2	0.16
1.07-1.17	12 sec.		1.1 - 1.2	13 sec
0.92-1.07	Indefinite		0.6 – 0.88	21 sec
0.7 – 0.92	20 sec		0.45 – 0.6	11 sec
0.5 – 0.7	10 sec		0 – 0.45	0.16 sec
0 – 0.5	0.1 sec			



Randomization of Inverter Disconnect and Reconnect

If voltage limits are exceeded and inverter disconnection is imminent, disconnection shall employ timing randomization so that multiple inverters do not disconnect simultaneously for the same system voltage disturbance. And after such disconnection, inverters shall reconnect using timing randomization to avoid multiple inverters connecting simultaneously after a system disturbance. The randomization of timing for disconnection and reconnection scenarios shall be:

- Disconnection: If voltage limits are exceeded, inverters shall disconnect at a random time during a window of an additional 0 to 10% beyond the elapsed time from initial fault.
- Reconnection: After an inverter has disconnected due to a system disturbance, it will reconnect at a random time during a window of an additional 0 to 10 seconds beyond the earliest allowable reconnection time.

Extended Frequency Ride-Through:

Inverters shall accommodate, at a minimum, underfrequency and overfrequency operation in compliance with the WECC Off Nominal Frequency Load Shedding Plan, as provided in the table below. In general the inverter would not trip off line at any frequency greater than 57 Hz or less than 60.3 Hz.

WECC Off Nominal Frequency Load Shedding Limits

Underfrequency Limit	Overfrequency Limit	Minimum Time*
>59.4 Hz	< 60.6 Hz	N/A (continuous operation)
≤59.4 Hz	≥60.6 Hz	3 minutes
≤58.4 Hz	≥61.6 Hz	30 seconds
≤57.8 Hz		7.5 seconds
≤57.3 Hz		45 cycles
≤57.0 Hz	≥61.7 Hz	Instantaneous trip

* Minimum Time is the time the inverter should stay interconnected with the PV generator power being supplied to the grid.

Communications:

Inverters will have communications capabilities and security control mechnanism that will comply with all applicable System Requirements (SRs) of standard ISA 99.03.03 for Security for Industrial Automation and Control Systems: System Security Requirements and Security Assurance Levels, Draft 2, Edit 30, published September 2010. It is also desirable (but not required) that the inverter and its associated computing components shall be ISA-099 certified/accredited.

3.6 *Supplemental Generating Facility Requirements*

Fault Detection - A Generating Facility with an SCCR exceeding 0.1 or one that does not cease to energize SDG&E's Distribution System within two seconds of the formation of an Unintended Island shall be equipped with protective functions designed to detect Distribution System faults, both line-to-line and line-to-ground, and shall cease to energize SDG&E's Distribution System within two seconds of the initiation of a fault.

Will have to implement directional overcurrent and line ground fault detection in the existing relays. Requires replacement of existing open delta VTs with wye-wye VTs.

Transfer Trip - For a Generating Facility that cannot detect Distribution System faults (both line-to-line and line-to-ground) or the formation of an Unintended Island, the facility must cease to energize SDG&E's Distribution System within two seconds. SDG&E may require a Transfer Trip system or an equivalent Protective Function.

Reclose Blocking - Where the aggregate Generating Facility capacity exceeds 15% of the maximum rating of any automatic reclosing device, SDG&E may require additional protective functions, including, but not limited to, reclose-blocking on some of the automatic reclosing devices.

Unknown if required until SDG&E performs interconnection study.

4 Operating Requirements

4.1 *Generator Step-up Transformer*

The available voltage taps of a Generating Unit's step-up transformer must be reviewed by SDG&E for their suitability with SDG&E's system. The Generator is to request this review before acquiring the transformer.

SDG&E shall determine which voltage taps would be suitable for a step-up transformer for the Generator's proposed project. Suitable taps are required to give the transformer the essential capacity for the generator to:

- Deliver maximum reactive power to SDG&E's system at the point of interconnection (generator operating at 90 percent lagging power factor) and,
- Absorb maximum reactive power from SDG&E's system (generator operating at 95 percent leading power factor).

The Generating Unit's transformer, with correct voltage taps, helps maintain a specified voltage profile on SDG&E's system for varying operating conditions. Actual voltage tap settings can be different for transformers connected at the same voltage level, depending upon their geographic location.

4.2 *Power Quality Requirements*

Voltage Fluctuation Limits - A generator connected to the SDG&E system must not cause harmful voltage fluctuations or interference with service and communication facilities. Any generating facility that does so is subject to being disconnected from the SDG&E system until the condition has been corrected.

Harmonics Limits - All generators shall comply with the voltage and current harmonic limits specified in IEEE Standard 519-1992, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

- The harmonic content of the voltage and current waveforms in the SDG&E system must be restricted to levels which do not cause interference or equipment-operating problems for SDG&E or its customers.
- Many methods may be used to restrict harmonics. The preferred method is to install a transformer with at least one delta connection between the generator and the SDG&E system. This method significantly limits the amount of voltage and current harmonics entering the SDG&E system. Generation system configuration with a wye-grounded generator and a two-winding (both wye-grounded) transformer shall not be allowed.
- When the Generating Facility is serving balanced linear loads, harmonic current injection into SDG&E's Distribution System at the PCC shall not exceed the limits stated in Table 3 shown in Section 3.3 of this handbook. The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in SDG&E's Distribution System

without the Generating Facility connected (IEEE 1547-4.3.3). The harmonic distortion of a Generating Facility located at a Customer's site shall be evaluated using the same criteria as for the Host Loads.

4.3 *Under-frequency Operation*

SDG&E controls system frequency, and the Generating Facility shall operate in synchronism with SDG&E's Distribution System. Whenever SDG&E's Distribution System frequency at the PCC varies from and remains outside of the normal (nominally 60 Hz) by the predetermined amounts set forth in Table 2 shown in Section3.3, the Generating Facility's Protective Functions shall cease to energize SDG&E's Distribution System within the stated maximum trip time.

5 Operating Procedures

5.1 *CVR Standards*

In 1977, the CPUC mandated the Conservation Voltage Reduction (CVR) standards. Approximately 95% of SDG&E substations are CVR and the remaining are NON-CVR. For CVR substations, the voltage maximum limit is 12.3kV and the adjustable voltage range shall be 11.9kV to 12.3kV. For NON-CVR substations, the voltage maximum limit is 12.6kV and the adjustable voltage range shall be 12.1kV to 12.6kV. The specific voltage set point will be provided to the interconnect customer after completion of load flow modeling with the generator on the distribution circuit.

5.2 *Voltage Control Operation and Other Service Requirements*

The Generating facility operator shall operate any voltage control (i.e., generator controls, shunt capacitors) at the direction of the SDG&E Designated Control Center and in accordance with applicable provisions of applicable agreements, applicable tariff(s), CAISO requirements if required and other electric service schedules. The facility operator shall insure the orders are understood and passed on to subsequent shift operator as appropriate to insure that any relief or backup operator is aware of the current SDG&E voltage instruction. The Generator is responsible for the safe operation and interruption and de-energization of the customer-owned voltage control devices when required.

Whenever primary relays or protective devices are out of service, backup or secondary relays must be available to clear faults. When restoring any relays that have been out of service, the Generator's designated representative shall verify that the contacts of any such relays, which are normally open, are in fact open. The Generator must ensure that relays do not have standing trip output.

5.3 *Unusual or System Emergency Conditions*

SDG&E is responsible for complying with all directions from the CAISO regarding management and alleviation of the System Emergency, unless such compliance would impair the Health and Safety of personnel or the general public. As directed by the CAISO, SDG&E will be responsible for communicating with Generating Facilities regarding emergencies. Unusual operating conditions or other factors that have affected or may affect SDG&E's electric system (e.g., abnormal voltages or loading or unbalanced loading) must be reported to the SDG&E Designated Control Center as soon as possible. Conditions imperiling life or property shall be reported to the SDG&E Designated Control Center immediately.

6 Energization and Synchronization Requirements

6.1 *Purpose*

The following is SDG&E's procedure for performing pre-parallel inspections and preparing to energize and synchronize the generator to SDG&E's Distribution System. All time requirements must be met for SDG&E to provide the Generating Units with timely service.

Any inspections required by local government agencies must be completed and permits signed off prior to the pre-parallel date. Failure to meet the succeeding requirements within the timeframes specified may result in a delay to successful operations parallel to the SDG&E system.

6.2 *Design Review and Interconnection Facilities Inspection*

SDG&E shall have the right to review the design of an Owner/Operator's Generating and Interconnection Facilities and to inspect an Owner/Operator's Generating and/or Interconnection Facilities prior to the commencement of Parallel Operation with SDG&E's Distribution System. SDG&E may require an Owner/Operator to make modifications as necessary to comply with the requirements of this Handbook. SDG&E's review and authorization for Parallel Operation shall not be construed as confirming or endorsing the Owner/Operator's design, nor as warranting the Generating and/or Interconnection Facility's safety, durability or reliability. SDG&E shall not, by reason of such review or lack of review, be responsible for the strength, adequacy, or capacity of such equipment.

6.3 *Pre-parallel Testing*

Commissioning Testing, where required, will be performed on-site to verify protective settings and functionality. Upon initial Parallel Operation of a Generating Facility, or any time interface hardware or software is changed that may affect the functions listed below, a Commissioning Test must be performed. An individual qualified in testing protective equipment (professional engineer, factory-certified technician, or licensed electrician with experience in testing protective equipment) must perform Commissioning Testing in accordance with the manufacturer's recommended test procedure to verify the settings and requirements per this handbook.

SDG&E may require that a written commissioning test procedure be submitted at least 10 working days prior to the performance of the commissioning test. SDG&E has the right to witness Commissioning Tests. SDG&E may also require written Certification by the installer describing which tests were performed and their results. Protective Functions to be tested during commissioning, particularly with respect to non-Certified Equipment, may consist of the following:

- Over and under voltage
- Over and under frequency

- Anti-Islanding Function (if applicable)
- Non-Export Function (if applicable)
- Inability to energize dead line
- Time delay on restart after utility source is stable
- Utility system fault detection (if used)
- Synchronizing controls (if applicable)
- Other Interconnection Protective Functions that may be required as part of the Interconnection Agreement

Commissioning Test shall include visual inspections of the interconnection equipment and protective settings to confirm compliance with the interconnection requirements.

Other checks and tests that may need to be performed include:

- Verifying final Protective Function settings
- Trip test
- In-service test

6.3.1 Certified Equipment

Generating Facilities qualifying for Simplified Interconnection must incorporate Certified Equipment that has, at a minimum, passed the Type Tests and Production Tests described in this handbook and are judged to have little or no potential impact on SDG&E's Distribution System. For such Generating Facilities, it is necessary to perform the following tests:

1) Protective function settings that have been changed after Production Testing will require field verification. Tests shall be performed using injected secondary frequencies, voltages and currents, applied waveforms, a test connection using a Generator to simulate abnormal utility voltage or frequency, or varying the set points to show that the device trips at the measured (actual) utility voltage or frequency.

2) The Non-Islanding Function will be checked by operating a load break disconnect switch to verify the Interconnection equipment ceases to energize SDG&E's Distribution System and does not re-energize it for the required time delay after the switch is closed.

3) The Non-Exporting Function shall be checked using secondary injection techniques. This function may also be tested by adjusting the Generating

Facility output and local loads to verify that the applicable Non-Exporting criteria (i.e., reverse power or under power) are met.

The Supplemental Review or an Interconnection Study may impose additional components or additional testing.

6.3.2 Non-Certified Equipment

Non-Certified Equipment shall be subjected to the appropriate tests described in Rule 21 under Type Testing (Section J.3.) as well as those described in Certified Equipment Commissioning Tests (Section J.5.c.). With SDG&E's approval, these tests may be performed in the factory, in the field as part of commissioning, or a combination of both. SDG&E, at its discretion, may also approve a reduced set of tests for a particular Generating Facility or, for example, if it determines it has sufficient experience with the equipment.

6.3.3 Verification of Settings

At the completion of Commissioning testing, the Owner/Operator shall confirm all devices are set to SDG&E-approved settings. Verification shall be documented in the Commissioning Test Certification.

6.4 *Requirements for Commercial (Parallel) Operation*

An Owner/Operator's Generating Facility and Interconnection Facilities shall be reasonably accessible to SDG&E personnel as necessary for SDG&E to perform its duties and exercise its rights under its tariffs approved by the Commission, and any Interconnection Agreement between SDG&E and the Owner/Operator.

An Owner/Operator shall operate and maintain its Generating Facility and Interconnection Facilities in accordance with Prudent Electrical Practices and shall maintain compliance with this Handbook.

SDG&E may limit the operation, disconnect, or require the disconnection of an Owner/Operator's Generating Facility from SDG&E's Distribution System at any time, with or without notice, in the event of an Emergency, or to correct Unsafe Operating Conditions. SDG&E may also limit the operation, disconnect, or require the disconnection of an Owner/Operator's Generating Facility from SDG&E's Distribution System upon the provision of reasonable written notice: 1) to allow for routine maintenance, repairs or modifications to SDG&E's Distribution System; 2) upon SDG&E's determination that a Owner/Operator's Generating Facility is not in compliance with this Handbook and any applicable tariffs or rules that apply to the interconnection; or 3) upon termination of the Interconnection Agreement. Upon the Owner/Operator's written request, SDG&E shall provide a written explanation of the reason for such curtailment or disconnection.

6.4.1 Trip Tests

Interconnection Protective Functions and devices (e.g., reverse power relays) that have not previously been tested as part of the Interconnection Facilities with their associated interrupting devices (e.g. contactor or circuit breaker) shall be trip tested during commissioning. The trip test shall be adequate to prove that the associated interrupting devices open when the protective devices operate. Interlocking circuits between Protective Function devices or between interrupting devices shall be similarly tested unless they are part of a system that has been tested and approved during manufacturing.

6.4.2 In-service Tests

Interconnection Protective Functions and devices that have not previously been tested as part of the Interconnection Facilities with their associated instrument transformers or that are wired in the field shall be given an in-service test during commissioning. This test will verify proper wiring, polarity, CT/PT ratios, and proper operation of the measuring circuits. The in-service test shall be made with the power system energized and carrying a known level of current. A measurement of the magnitude and phase angle of each Alternating Current (AC) voltage and current connected to the protective device shall be made and the results shall be compared to expected values. For protective devices with built-in Metering Functions that report current and voltage magnitudes and phase angles, or magnitudes of current, voltage, and real and reactive power, the metered values may be used for in-service testing. Otherwise, portable ammeters, voltmeters, and phase-angle meters shall be used.

6.4.3 Periodic Testing

Periodic Testing of Interconnection-related Protective Functions shall be performed as specified by the manufacturer, or at least every four years. All periodic tests prescribed by the manufacturer shall be performed. The Owner/Operator shall maintain periodic test reports or a log for inspection by SDG&E. Periodic Testing conforming to SDG&E test intervals for the particular Line Section may be specified by SDG&E under special circumstances, such as high fire hazard areas. Batteries used to activate any Protective Function shall be checked and logged once per month for proper voltage. Once every four years, these batteries must be replaced or a discharge test must be performed.

7 Attachments

7.1 *Tariffs*

SDG&E offers open access, wholesale distribution service to eligible customers, under the rates, terms and conditions set forth by the CPUC, California Public Utilities Commission. Below is the link to the SDG&E Wholesale Distribution Open Access Tariff (WDAT) outlining integration of Distribution SGIP, Small Generator Interconnection Procedures, and Distribution LGIP, Large Generator Interconnection Procedures, to the WDAT.

http://www.sdge.com/rates-regulations/tariff-information/open-access-ferc-tariffs

7.2 *Interconnection Applications*

For an interconnection to the distribution system for a project that *does not* intend to resell the power generated back to the market, a Rule 21 Interconnection Application is required to be completed and issued to SDG&E. Upon receipt of the application, SDG&E will review the request as outlined in Rule 21. Below is an internet link to the application document and other information about interconnection.

http://www.sdge.com/rates-regulations/tariff-information/open-access-ferc-tariffs

For an interconnection to the distribution system that intends to resell the power generated back to the market and the project is no larger than 20 MW in size, a Small Generation Interconnection Procedures (SGIP) Interconnection Application from SDG&E's Wholesale Distribution Open Access Tariff (WDAT) is required to be completed and submitted to SDG&E. Upon receipt of the application, SDG&E will review the request as outlined in the SGIP WDAT tariff.

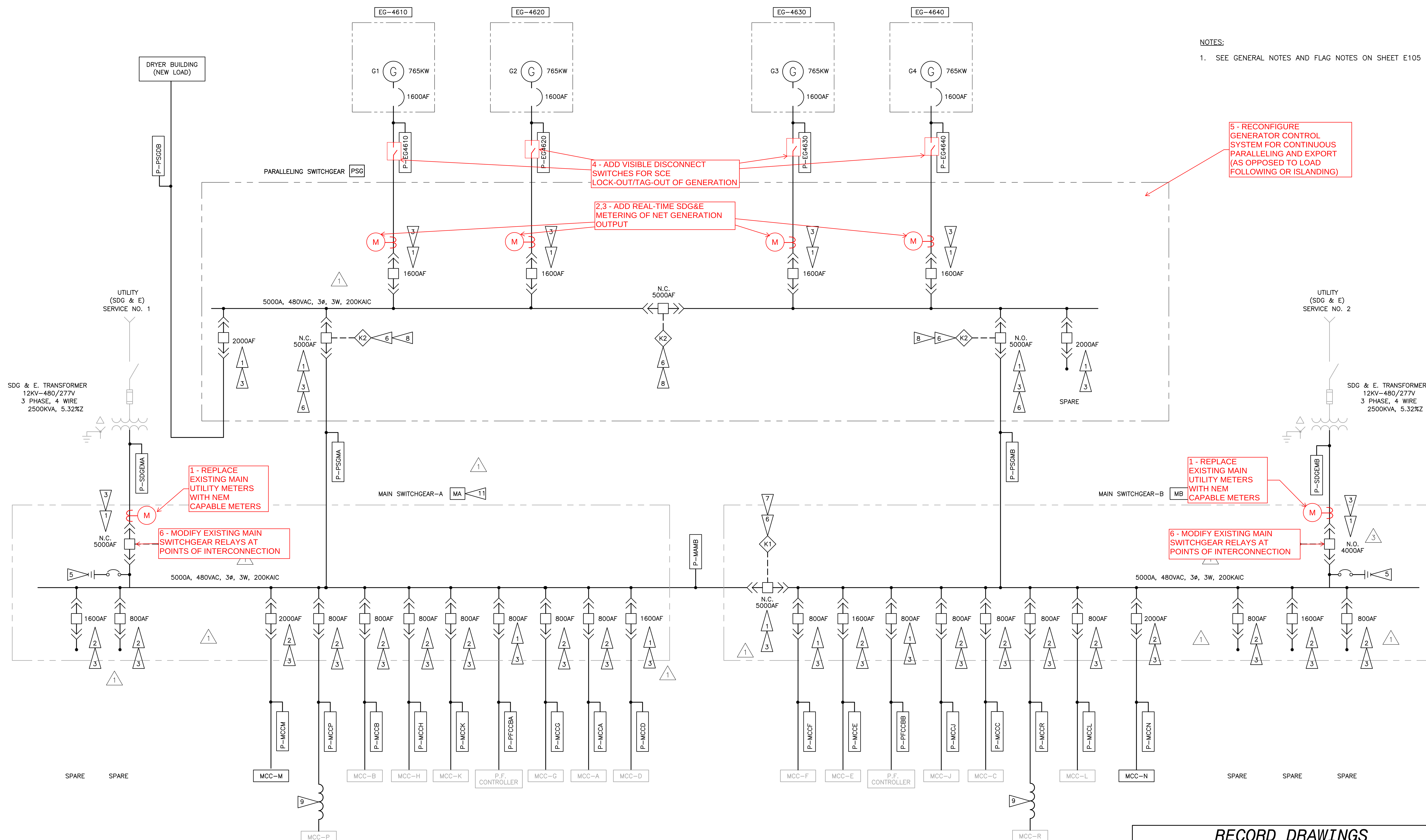
For an interconnection to the distribution system for a project that intends to resell the power generated back to the market and is larger than 20 MW in size, a Large Generation Interconnection Procedures (LGIP) Interconnection Application from SDG&E's Wholesale Distribution Open Access Tariff (WDAT) is required to be completed and submitted to SDG&E. Upon receipt of the application, SDG&E will review the request as outlined in the LGIP WDAT tariff.

Below, and as shown in section 7.1, is an internet link that contains the WDAT application documents and summaries as well as other information about generation interconnections to SDG&E's system.

http://www.sdge.com/rates-regulations/tariff-information/open-access-ferc-tariffs

NOTES:

1. SEE GENERAL NOTES AND FLAG NOTES ON SHEET E105



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REV. NO.	DATE	DRWN	CHKD	REMARKS
3	6/2009	CLM	PAB	CONFORMED TO CONSTRUCTION RECORDS
2	7/24/06	PJR		CONFORMED
1	6/9/06	DIS		ADDENDUM NO. 5

DESIGNED BY: PC
DRAWN BY: LAJ, EPM
SHEET CHK'D BY: PJG
CROSS CHK'D BY:
APPROVED BY:
DATE: MARCH 13, 2007

CDM Camp Dresser & McKee Inc.
consulting engineering construction operations

THIS DRAWING WAS ORIGINALLY APPROVED FOR CONSTRUCTION BY PAUL CRIVELL ON 7/24/06 AND SEALED BY PAUL CRIVELL A LICENSED PROFESSIONAL ENGINEER IN THE STATE OF CALIFORNIA NO. 17890

VERIFY SCALE
THIS BAR IS ONE INCH LONG AT FULL SCALE

ENCINA WASTEWATER AUTHORITY
CARLSBAD, CALIFORNIA
ENCINA WATER POLLUTION CONTROL FACILITY
PHASE V EXPANSION PROJECT
ENERGY MANAGEMENT FACILITIES IMPROVEMENT

SINGLE LINE DIAGRAM
SWITCHGEAR

PROJECT NO. 28480-44235
FILE NAME: ESLDSE104

E104

SHEET 56 OF 127

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LAST PRINTED: 9/10/2009 5:13 PM LAST SAVED: 9/10/2009 5:09 PM

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Technical Memorandum

FINAL

Prepared for: Encina Wastewater Authority

Project title: Biosolids, Energy, and Emissions

Project no.: 150871.004

Technical Memorandum 4

Subject: Technology Evaluations for Biogas Production

Date: February 14, 2018

To: Scott McClelland, Assistant General Manager

From: Scott Lacy, Project Manager

Prepared by: ______________________
Alison C. Nojima, P.E., California License C 84933

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Nancy Andrews

Limitations:

Acknowledgements

Significant contributions to this technical memorandum were made by:

- Tracy Chouinard, Ph.D.
- Yinan Qi, Ph.D.
- William Pevec, Staff Engineer

Table of Contents

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List of Abbreviations

°C	degree(s) Celsius
BC	Brown and Caldwell
BEE	Biosolids Energy and Emissions
CCR	California Code of Regulations
CH_4	methane
cm	centimeter(s)
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
d	day(s)
DG	digester gas
DGE	diesel gallon equivalent
EWA	Encina Wastewater Authority
EWPCF	Encina Water Pollution Control Facility
FOG	fats, oil, and grease
ft^3	cubic foot/feet
GHG	greenhouse gas
gpd	gallon(s) per day
H_2S	hydrogen sulfide
HLR	hydraulic loading rate
HSW	high-strength waste
IC	internal combustion
kHz	kilohertz
kV	kilovolt(s)
kW	kilowatt(s)
L	liter(s)
LACSD	Sanitation Districts of Los Angeles County
lb	pound(s)
lb-VS/day	pounds per volatile solids per day
lb-VS/ft^3	pounds per volatile solids per cubic feet
LCFS	Low Carbon Fuel Standard
mg	milligram(s)
MG	million gallons
mgd	million gallons per day
N	nitrogen
N/A	not applicable
NG	natural gas
NH_3	ammonia
NH_{4+}	ammonium
NO_x	nitrogen oxides
OLR	organic loading rate
O&M	operations and maintenance
$PM_{2.5}$	particulate matter with a diameter of less than 2.5 micrometers
PM_{10}	particulate matter with a diameter of less than 10 micrometers
PMP	Process Master Plan
ppbv	parts per billion by volume
ppmb	parts per million by volume
RIN	Renewable Identification Number
SB	Senate Bill
scfd	standard cubic foot/feet per day
scfm	standard cubic foot/feet per minute
SCR	selective catalytic reduction
SJSCRWF	San José-Santa Clara Regional Wastewater Facility
SO_x	sulfur oxides
SSO	source-separated organics
SWEET	Solids Water Energy Evaluation Tool
THP	thermal hydrolysis process
TM	technical memorandum
TS	total solids
TWAS	thickened waste activated sludge
VOC	volatile organic compound
VS	volatile solids
WAS	waste activated sludge
WM	Waste Management
WWTP	wastewater treatment plant

Executive Summary

The Encina Water Pollution Control Facility (EWPCF) operates an Alternative Fuels Receiving Facility to accept high-strength waste (HSW) that is co-digested with municipal solids to increase biogas production. This Technical Memorandum (TM) 4 provides an evaluation of enhancements to the biogas train including alternative technologies for increasing biogas production, increasing the utilization and recovery of the biogas, and improving the treatment and management of the biogas. Biogas train enhancements include biogas treatment (conditioning), biogas storage, and waste activated sludge (WAS) pretreatment to improve volatile solids reduction and increase biogas production. Screening and ranking of technologies was performed in a workshop on August 16, 2017, with Encina Wastewater Authority (EWA) staff. The technologies that passed the fatal-flaw filter are summarized in Table ES-1. Technologies that did not pass the fatal-flaw filter were eliminated. Those technologies that passed the fatal-flaw filter moved on and were assessed using evaluation criteria developed to reflect EWA's values and goals for the project, which are summarized in Table 2-3.

Table ES-1. Biogas Train Enhancements

Gas Treatment Technology	Gas Storage Technology	WAS Pretreatment Technology
Gas conditioning	Piston-type gas holder	WAS-only Cambi THP
Gas conditioning + exhaust treatment	Dual-membrane gas storage	
Biogas upgrading		

THP = thermal hydrolysis process

In addition, the Brown and Caldwell (BC) team evaluated the possibility of increasing co-digestion of HSW at EWPCF to increase biogas production for use in the alternative power production technologies.

Section 1: Introduction

EWA has undertaken a Biosolids Energy and Emissions (BEE) Plan, which will serve to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed Process Master Plan (PMP). The BEE Plan has several goals:

- Provide a comprehensive analysis of all project elements, including biosolids treatment, gas use, energy generation, and waste heat
- Address capacity limitations in the solids-handling process at EWPCF
- Assess which alternative is likely to be the most cost-effective and sustainable solution for EWA
- Move EWPCF toward greater energy independence
- Reduce greenhouse gas (GHG) emissions

The purpose of TM 4 is to document the technology screening for co-digestion opportunities, sludge pretreatment technologies, and biogas treatment and storage alternatives. This TM does not provide an alternatives analysis, but provides insight to the methodology and rationale that were used to select alternatives that will move forward for further analysis in the Solids Water Energy Evaluation Tool (SWEET) model development.

1.1 TM 4 Purpose and Scope

TM 4 summarizes the methodology for screening and evaluating biogas train enhancements, the technologies evaluated, and how these alternatives were ranked to determine which would move forward in the SWEET analysis. Biogas train enhancements generally fall into three categories: gas treatment, gas storage, and increased gas production. Those alternatives for gas treatment and storage are necessarily linked to the alternative power production options selected under Task 3 and summarized in TM 3. Co-digestion is compatible with the stabilization alternatives selected under Task 2 and summarized in TM 2, but a range of co-digestion possibilities were explored under Task 4 and are described herein. Recommended technologies and co-digestion operating schemes selected under this task will be advanced for further analysis and will be combined with the solids-handling and waste heat alternatives developed under Tasks 2, 3, and 5. Screening and ranking of technologies was performed in a workshop on September 19, 2017, with EWA staff. Meeting minutes from this workshop are provided as Attachment A.

1.2 Background Information

This TM is based on the conclusions developed in TM 1, which addressed the baseline energy profiles and projections, established a mass balance for the solids-handling system, and evaluated sludge flows and loads projections performed under the PMP. Where preliminary calculations were performed, the baseline data were used in evaluation. As described in Section 1.1, screening and evaluation of solids-processing technologies is described in TM 2, while screening and evaluation of alternative power production technologies is described in TM 3. Only those alternatives for biogas train enhancement that are compatible with technologies selected under Tasks 2 and 3 were evaluated under Task 4.

Additional information regarding EWA's experience with co-digestion is included in a TM written by Trussel Tech (Attachment B) that summarizes EWA's experience with alternative fuels codigestion to date, includes a literature review of alternative fuels codigestion, and presents process monitoring recommendations (Noelte 2017).

Section 2: Identification and Screening of Technologies for Gas Treatment

This section describes potential gas treatment technologies, including gas treatment for internal-combustion (IC) engines and biogas upgrading for pipeline injection or vehicle fuel, followed by a fatal-flaw screening of gas treatment and rankings of gas treatment technologies.

2.1 Gas Treatment for Internal-Combustion Engines

Four 750-kilowatt (kW) IC engines are currently operated on raw biogas; however, EWPCF typically only runs two engines at a time due to air permit restrictions (discussed in TM 6). When excess biogas is available, it can be sent to the thermal dryer, where it is blended with natural gas (NG). This section discusses gas treatment options that could improve IC engine lifespan and reduce the frequency of maintenance activities for both the engines and thermal dryer.

2.1.1 Gas Conditioning

Biogas typically contains methane (CH_4), carbon dioxide (CO_2), water vapor, hydrogen sulfide (H_2S), ammonia (NH_3), nitrogen (N), volatile organic compounds (VOCs), siloxanes, and trace amounts of other components. Some of these compounds can harm an IC engine and must be removed before combustion. For example, H_2S can cause engine corrosion, and siloxanes oxidize during combustion to form silica particles that can damage an engine. Additionally, the combustion of some compounds, such as H_2S, produces harmful and regulated air pollutants.

Gas treatment system design is driven by raw biogas flowrate, raw biogas quality, and post-treatment requirements. Post treatment requirements are dependent on fuel end use (IC engines, IC engines combined with exhaust treatment, pipeline injection, and direct vehicle fueling); however, all options require low H_2S and siloxane concentrations and minimal water content. Raw biogas quality characteristics at EWPCF are presented in Table 2-1. Components included in the table are H_2S and three of the most common siloxane species (D3, D4, and D5). The data presented in Table 2-1 are from two gas samples taken in 2011 and 2012.

Table 2-1. Raw Biogas Quality at EWPCF

Sample Date	H_2S (ppmv)	D3 Siloxanes (ppbv)	D4 Siloxanes (ppbv)	D5 Siloxanes (ppbv)
December 15, 2011	139	18.4	115	734
January 23, 2012	125	20.5	433	4,480
Average	132	19.5	274	2,607

ppbv = parts per billion by volume; ppmv = parts per million by volume.

The H_2S concentrations are relatively low for biogas, but the observed concentrations still exceed most IC engine inlet specifications, the recommended value for compressed NG (CNG) vehicle fuel (SAE J1616), or the California Rule 30 H_2S limit for pipeline injection. Additionally, even though total siloxane concentrations are relatively moderate for biogas, the raw biogas does not meet most IC engine fuel specifications, siloxane inlet requirements for selective catalytic reduction (SCR), or the California Rule 30 siloxane limit for pipeline injection.

It should also be noted that modifications to upstream biogas-producing systems may alter raw biogas quality. For example, thermophilic digestion may increase siloxane concentrations, and additional high strength waste quantities may increase H_2S and NH_3 concentrations. If a Cambi thermal hydrolysis processing system is added upstream, significant concentrations of NH_3 may be present in the biogas.

A biogas conditioning system should be designed to meet all the fuel quality requirements for the selected alternative for biogas utilization; partial biogas treatment is not recommended. Typically, biogas conditioning systems include H_2S, moisture, and siloxane removal and compression. Gas conditioning systems can either be engineered in separate components or provided as a whole system by a single equipment vendor, such as Unison Solutions or DMT Clear Gas Solutions. Individually specifying components often allows the design engineer to provide a more flexible layout that can be tailored to space requirements and maintenance access. Packaged systems can be desirable since treatment steps are highly codependent. Figure 2-1 shows an example of a gas conditioning system located at the Santa Rosa Laguna Treatment Plant. A process flow diagram for a sample gas conditioning system is presented in Figure 2-2.

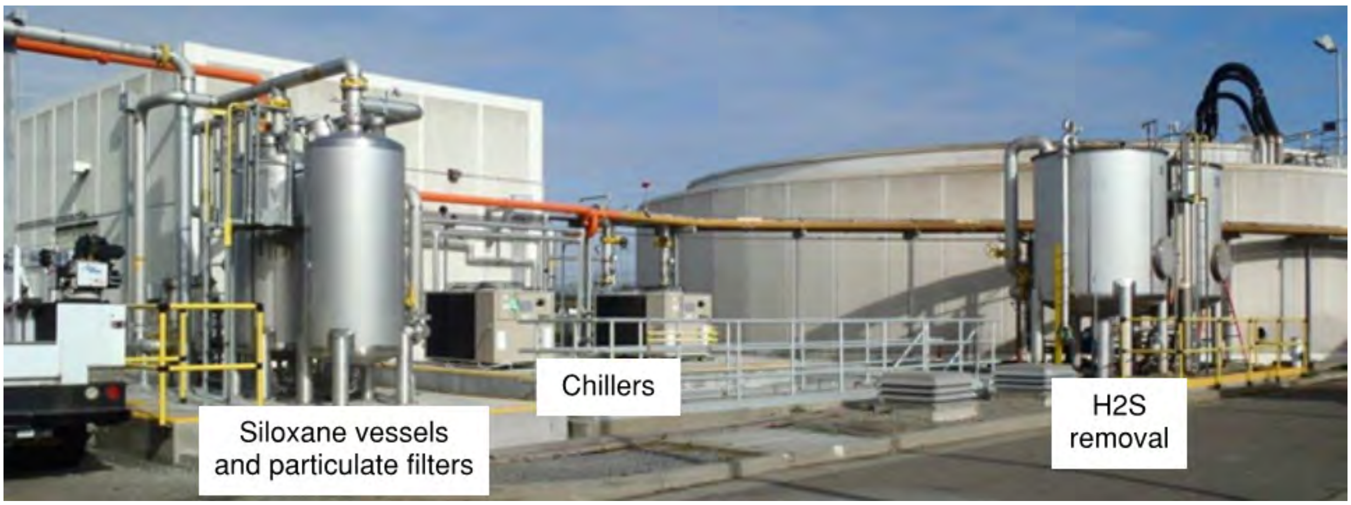

Figure 2-1. Gas conditioning system at the Santa Rosa Laguna Treatment Plant, including H_2S removal vessels, siloxane removal vessels, and chillers

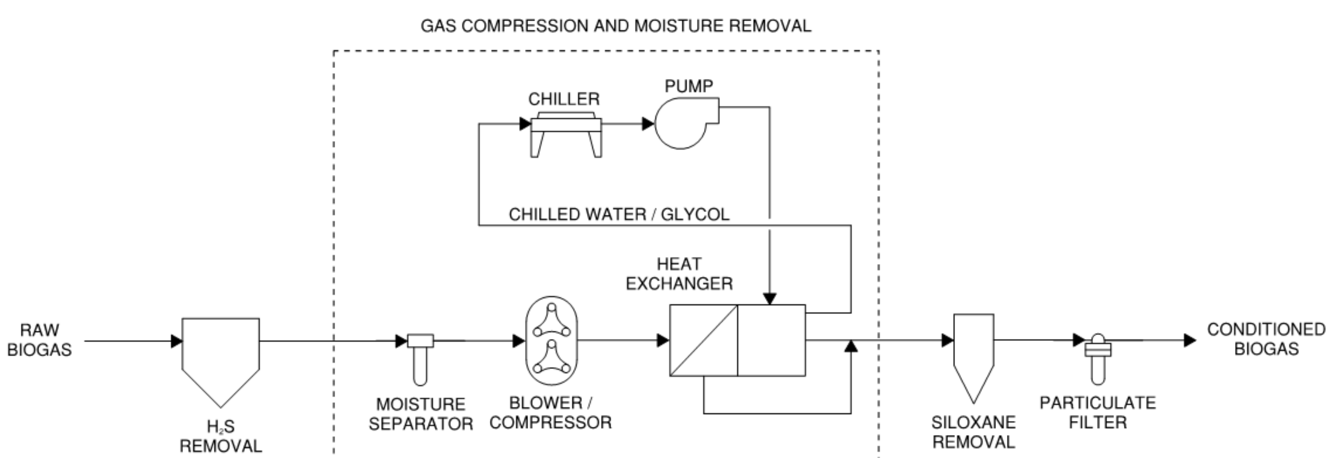

Figure 2-2. Process flow diagram for a typical gas conditioning system. Configurations may vary, depending on equipment suppliers and treatment needs.

H_2S removal is typically the first step in a biogas conditioning system. H_2S is removed using an iron-oxide media, which operates best at ambient temperatures and high moisture content (saturated gas). Thus, raw biogas can be sent through H_2S removal vessels before moisture removal or compression. Multiple types of H_2S removal media are currently available, including iron sponge, SulfaTreat, and granular iron hydroxide. H_2S removal media must be replaced regularly, which incurs additional operating and maintenance costs. Lifespan and maintenance requirements vary among the different media types. H_2S removal systems are sized based on biogas flow rate and the biogas H_2S concentration. At least two vessels are recommended so that one vessel can be taken offline during media removal or maintenance. Multiple vessels may be placed in series to treat biogas with high H_2S concentrations.

NH_3 removal may be required if significant quantities of NH_3 are detected consistently in the biogas. In this case, NH_3 removal vessels would be placed downstream of the H_2S removal vessels. NH_3 concentrations are often not high enough to warrant specialized removal vessels, and NH_3 can be effectively removed via carbon adsorption in the downstream siloxane removal vessels. NH_3 in the biogas increases nitrogen oxide (NO_x) emissions in IC engines. After passing through the H_2S removal vessels, the biogas pressure must be increased and moisture must be removed because siloxane removal systems require a dry gas. Gas pressure must also meet the inlet requirements of the selected utilization alternative. Water is removed from the wet biogas through a moisture removal system that cools the biogas to condense water vapor; liquid water can then be drained and mist can be removed through a moisture separator. Gas pressure can be increased with blowers or compressors, depending on the desired outlet pressure. Compression increases the biogas temperature above the allowable inlet temperature for the downstream activated carbon media. A gas cooling heat exchanger is required after the pressure is boosted; the cooled biogas must then be reheated slightly before entering the siloxane removal system. The reheat step aims to return the biogas to ambient temperature and raise the temperature approximately 20 degrees Fahrenheit above the dew point to prevent condensation. Cooling and reheating can be achieved through a series of heat exchangers or via a single dual-core heat exchanger.

The most common siloxane removal method is adsorption via activated carbon media, which has microscopic pore spaces and a resulting high surface area to particle size ratio. This high ratio makes activated carbon an effective media for adsorbing molecular contaminants. The media typically becomes exhausted after 3 to 6 months and must be replaced regularly, incurring additional operating and maintenance costs. Like H_2S removal, at least two vessels are recommended so that one vessel can be taken offline during media removal or maintenance. Multiple vessels may be placed in series to treat biogas with high siloxane concentrations and to avoid siloxane breakthrough that can harm downstream equipment. Particulate filters are usually installed downstream to capture any activated carbon particles that become suspended in the biogas.

2.1.2 Gas Conditioning and Exhaust Treatment

If modifications to the existing IC engine operation are made, such as increased fuel usage or output above the current air permit limitations, an oxidation catalyst may be required to meet regulatory exhaust limits for carbon monoxide, which are discussed in greater detail in TM 6.A survey of several leading manufacturers of exhaust treatment equipment indicates that to meet exhaust emission requirements, biogas fuel must be treated prior to combustion to limit sulfur species to no more than 20 ppmv and siloxanes to no more than 20 ppbv or non-detect limits. These values are much lower than the raw biogas concentrations presented in Table 2-1.

Prior to reviewing the air permit, SCR systems to meet NO_x limits were previously considered; however, they are not necessary to meet the permit requirements. In addition, installing an SCR system for exhaust treatment would be cost prohibitive as the Power Building would need to be replaced due to space constraints and a relatively large footprint. On the fatal flaw criteria of compatibility and available space, SCR exhaust treatment fails the fatal flaw filter and will not be carried forward as an alternative.

2.2 Biogas Upgrades for Pipeline Injection or Vehicle Fuel

Biogas upgrading produces biomethane, a renewable NG substitute, which can be used as vehicle fuel in place of CNG or can be injected into a utility NG pipeline. These two biomethane end uses are described further in TM 3. Biogas upgrading first involves gas compression and gas conditioning to remove moisture, H_2S, and siloxanes from the raw biogas, similar to conventional gas conditioning processes described in Section 2.1.1. After contaminants are removed from the gas, the gas goes through a separation process to remove CO_2. The resulting product is a CH_4-rich process gas commonly referred to as biomethane, or renewable NG. Separation systems can be designed to achieve various levels of biomethane purity, up to 99+ percent CH_4. The CO_2 leaves the system in a CH_4-lean tail gas consisting of primarily CO_2 with up to 30 percent of the total biogas CH_4 depending on the gas separation technology used. Tail gas is typically wasted using a flare or thermal oxidizers and may require a supplemental NG feed to help the tail gas combust.

Several biogas separation technologies are available, including membranes, pressure swing adsorption, and water solvents. Figure 2-3 shows an example biogas upgrading system provided by Unison Solutions that utilizes membrane separation. Other typical biogas separation technology manufacturers include Air Liquide, Guild Associates, Greenlane Biogas, and DMT Clear Gas Solutions. These manufacturers typically supply flange-to-flange packaged solutions and design and fabricate the systems in-house. For one of these flange-to-flange systems, the client and design engineer provide a performance specification in which the inlet gas and desired product gas characteristics are described. At EWPCF, a biogas upgrading system specification in a pipeline injection application would include the product gas requirements to meet the standards of California Rule 30. EWA and BC have identified a San Diego Gas & Electric NG pipeline that runs to the north of the plant to potentially tie into if a pipeline injection alternative is selected. TM 3 provides more information on product gas requirements for pipeline injection and direct vehicle fueling.

Figure 2-3. Biogas upgrading system at San Mateo WWTP (California) using Unison's BioCNG system, which includes H_2S removal, moisture removal, compression, siloxane removal, and membrane separation

2.3 Fatal-Flaw Screening and Evaluation of Gas Treatment

The power production alternatives presented in Section 2 were first screened using four fatal-flaw criteria, which were applied uniformly across all technologies. The four criteria developed in conjunction with EWA staff include the following:

- **At least one successful North American installation of technology:** There must be at least one full-scale installation of the technology at a wastewater treatment plant (WWTP) in North America.
- **At least one successful installation and operation in a facility of similar size:** The technology should be sufficiently developed that it is applicable at a facility of comparable size to EWPCF to ensure compatibility.
- **Available space:** The technology must be accommodated within the limited available footprint at EWPCF.
- **Compatibility with plant site and any existing equipment:** The technology must be capable of being integrated into the existing EWPCF infrastructure.

For an alternative to be considered for the ranking process, the alternative must pass all four fatal-flaw criteria. The results of the fatal flaw screening exercise are presented in Table 2-2 and discussed in Section 2.3.

Table 2-2. Gas Treatment Fatal-Flaw Evaluation

Technology	Technology Maturity	Successful Operation	Available Space	Compatibility
Gas conditioning	Pass	Pass	Pass	Pass
Gas conditioning + exhaust treatment	Pass	Pass	Fail	Fail
Biogas upgrading	Pass	Pass	Pass	Pass

Alternatives that passed the fatal-flaw filter were further evaluated and ranked based on both economic and non-economic screening criteria. The BC team worked with EWA staff to develop a series of evaluation criteria that reflect the project goals, EWA's values, and EWA's general operational practices. Criteria weights were assigned in Workshop 2 with EWA staff. Criteria and weightings are presented in Table 2-3.

Table 2-3. Criteria and Weight for Technology Screening

Criterion	Description	Scoring Description	Weight
Proven technology performance	Proven and reliable technology with same configuration intended at Encina Long successful operating track record	Low score indicates no successful large-scale operating installations in North America or Europe, no successful demonstration-scale installations in North America or Europe, and unknown safety or reliability record High score indicates more than one successful operating installation in North America or Europe, more than one operating installation at a WWTP of at least 40 mgd in North America or Europe, track record duration > 5 years, and vendors in western United States	20%
Minimize life-cycle costs	Qualitative metric of program cost Capital and O&M costs based on existing EWA data or similar experience at other WWTPs Potential revenues from sales	Low score indicates high capital cost to build onsite facilities, high O&M costs, and low energy recovery efficiency High score indicates low capital cost to build onsite facilities, low O&M costs, and potential revenue	10%

Brown AND Caldwell

Table 2-3. Criteria and Weight for Technology Screening			
Criterion	Description	Scoring Description	Weight
Energy/resource recovery	Recovery of renewable energy	Low score indicates high energy requirement for onsite technology, technology does not recover energy as biogas, and low-efficiency recovery of renewable energy High score indicates a higher electrical efficiency	25%
O&M impacts	Impacts to existing plant O&M staff levels Complexity of new technology O&M and control systems Reliability of new technology (potential downtime) Minimal impacts to plant safety	Low score indicates more O&M time required, complex mechanical and control systems required compared with existing plant facilities, potential equipment downtime, and newer hazards High score indicates reduction in O&M staff time required, new technology is simple to operate and maintain, reliable with minimal downtime, and no new hazards	10%
Environmental impacts	Impacts to carbon footprint and air permitting	Low score indicates high carbon footprint for technology, and new permitting for environmental regulatory requirements High score indicates low carbon footprint for technology, reduced pollutant emissions, and no additional permitting for environmental regulatory requirements	15%
Community and stakeholder impacts	Minimize nuisance impacts such as dust, odors, vectors, aesthetics, noise, and traffic Assess impacts to partner agency issues/values as well as local planning codes and requirements	Low score indicates nuisance factors for onsite technology are difficult to mitigate High score indicates nuisance factors can be mitigated at plant site	10%
Project site compatibility	Assess compatibility of technology with available plant footprint Incorporation into existing treatment process	Low score indicates lack of site space for new facilities, requires abandonment of existing facilities, and difficult integration with existing plant High score indicates available footprint for new facilities and maintains space for future facilities, ease of integration with existing processes and facilities	10%

Table 2-4 shows the scoring results for the gas treatment technologies that passed the fatal-flaw filter. The scores for each alternative were also developed with EWA staff in Workshop 2. All alternatives passed the fatal-flaw filter. The rationale behind the scoring for each technology area is described below.

Table 2-4. Gas Treatment Technologies Scoring Evaluation			
Criterion	Gas Conditioning	Gas Conditioning + Exhaust Treatment	Biogas Upgrading
Proven technology performance	5	4	2
Minimize life-cycle costs	3	4	4
Energy/resource recovery	4	5	4
O&M impacts	4	3	4
Environmental impacts	3	4	5
Community and stakeholder impacts	4	5	5
Project site compatibility	5	4	4
Weighted score	4.05	4.25	3.85

Biogas upgrading is still considered an emerging technology and has fewer large-scale installations and less established equipment manufacturers. Biogas upgrading alternatives can bring in potential revenue from Low Carbon Fuel Standard (LCFS) and Renewable Identification Number (RIN) credits generated for producing renewable fuel, currently valued between $1 and $3 per diesel gallon equivalent produced (every 1 standard cubic foot per minute [scfm] of biogas produces approximately 5 diesel gallon equivalents of fuel per day) in addition to the value of the fuel itself. However, the biogas upgrading alternatives have relatively high capital costs when compared with an engine project, thus, lowering the life-cycle cost score to a 4. The approximate biogas production during the baseline period, potential quantity of renewable NG that can be generated, and potential RINs values associated with biogas upgrading are presented in Table 2-5.

Table 2-5. Biogas Upgrading Potential Assuming Existing Baseline Biogas Production [a]

Characteristic	Value
Biogas Production, cfm	500
Methane recovery, %	99.5
DGE/day	3,000
RINs/day	5,000
$Revenue/day	12,000
$Revenue/year	4.4M

a. Assumes 95% biogas upgrading uptime, RINs value of $2/RIN and LCFS value of $0.70/DGE.

DGE = diesel gallon equivalent

Biogas upgrading received the highest score for environmental impacts because biomethane replaces anthropogenic fuels with a biogenic, fully renewable fuel.

Section 3: Identification and Screening of Technologies for Gas Storage

Biogas storage is used to buffer or control variations in biogas production and maintain steady output from IC engines or other biogas uses. EWPCF has no dedicated biogas storage equipment; however, differences between biogas production and utilization in the existing IC engines are controlled by NG blending. The primary benefit of biogas storage at EWPCF is reducing the need for NG blending and the associated utility costs. Stored biogas from periods of excess production can be used to replace NG in times of low biogas production.

Because EWPCF's current gas management system and NG blending strategy provides effective control of the IC engines and helps utilize nearly all produced biogas, gas storage alternatives do not offer significant savings. It is noted that although NG blending increases NG costs, it provides a greater decrease in power costs due to increased IC engine output.

3.1 Identification of Applicable Technologies

This section identifies two biogas storage options—a piston-type gas holder and a dual-membrane type gas holder on the top of a digester. Both types have been in service for many years.

3.1.1 Piston-Type Gas Holder

The piston-type gas holder has a simple and linear relationship between piston height and stored gas volume. These types of gas holders are proven in the industry and provide reliable and robust storage. Figure 3-1 shows a piston-type gas holder that was installed at the San José-Santa Clara Regional Wastewater Facility (SJSCRWF) and Table 3-1 presents the pros and cons of this type of gas holder.

Figure 3-1. Piston-type gas holder installed at SJSCRWF with 50,000 cubic feet of active storage

Table 3-1. Advantages and Disadvantages of Piston-Type Gas Holder	
Advantages	**Disadvantages**
30-year life	High capital cost
Fixed storage pressure	Dry seal replacement at 15 years [a]
Direct/visual measurement of stored volume	Recoat at 15 years
Reliable operation/signal for blending control	

a. Industry experience shows that dry seal service life can be as long as 29 years, but replacement is recommended after 15 years.

Typically, dedicated gas storage tanks are sized for 10 to 60 minutes of biogas storage. Based on the plant's biogas production, this could result in a new 30- to 50-foot-diameter tank for gas storage, which is not compatible with the plant's available space and, therefore, does not pass the fatal-flaw filter.

3.1.2 Dual-Membrane Gas Storage

Gas storage can also be accomplished by installing a dual membrane above the concrete walls of a digester or on a slab on grade. With a dual-membrane storage system, the outer air membrane remains inflated in a fixed position while the inner membrane moves freely as biogas is stored or removed for use downstream. Figure 3-2 shows an example of a dual-membrane gas holder.

Figure 3-2. Dystor® gas holder system from Evoqua Water Technologies example installation

The dual-membrane type gas holders first came on the market in about 1987. However, dual-membrane gas holders with control signals that represent the gas production/consumption relationship are relatively new and have been in service for only about the last 5 years.

A dual-membrane gas storage system can be installed on top of one of the smaller digesters at EWPCF and can provide a feasible solution if gas storage and a digester cover are required. When installed as a digester cover, the dual-membrane system can double or triple the existing biogas storage space of one of the smaller digesters. Table 3-2 presents the pros and cons of this type of gas holder.

Table 3-2. Advantages and Disadvantages of Dual-Membrane Gas Holder	
Advantages	**Disadvantages**
Low capital cost	Membrane replacement at 10–20 years [a]
Adjustable operating pressure	Level detection is unproven, developing, and different for each manufacturer
Greater volume, if needed	Less robust than piston-type gas holder
	Limited fill/draw rates
	Requires continuous electric blower operation
	Digester-mounted membranes are difficult to access for repairs

a. *Industry experience shows that membrane service life can be as short as 7 years.*

One of the smaller existing EWPCF digesters can be retrofitted to a dual membrane gas holder, which meets the available space and compatibility requirements of the fatal-flaw filter. Dual membrane gas holders have been employed as digester covers at multiple moderate-sized WWTPs, including Yakima Regional WWTP in Washington and the City of Mansfield WWTP in Ohio. As a result, dual membrane gas holders also meet the successful installation requirements of the fatal-flaw filter. Economics will ultimately determine whether a dual membrane gas holder is a feasible gas storage option at EWPCF. If NG savings from better metering of stored biogas can be shown to exceed the capital and operating costs of dual membrane storage, this alternative may be feasible moving forward. Dual membrane gas holders will be further considered in the SWEET analysis.

3.2 Fatal-Flaw Screening and Evaluation of Gas Storage

The same four fatal-flaw criteria presented in Section 2 were applied to the gas storage alternatives. These results are presented in Table 3-3. If gas storage is required, one of the smaller digesters would be retrofitted to serve for the base tank of a dual membrane gas holder.

Table 3-3. Gas Storage Fatal-Flaw Evaluation				
Technology	**Technology Maturity**	**Successful Operation**	**Available Space**	**Compatibility**
Piston-type gas holder	Pass	Pass	Fail	Fail
Dual membrane gas holder	Pass	Pass	Pass	Pass

Section 4: Increased Gas Production: WAS Pretreatment

One way to increase biogas production from anaerobic digestion is to condition WAS to make it more readily biodegradable with WAS pretreatment technologies. WAS pretreatment technologies work on different principles to disintegrated cell walls. Some of these technologies have been discussed in TM 2. Technologies screened out in TM 2 were not considered further in this evaluation unless they presented a unique application. Many WAS pretreatment technologies are in research stage and are not commercially available. Those technologies were not included in this evaluation.

WAS pretreatment technologies evaluated in this section include:

- Ultrasonic pretreatment
- Electro kinetic disintegration
- Thermal hydrolysis
- Mechanical pretreatment

Brief introductions and a fatal-flaw screening evaluation of the WAS pretreatment technologies are provided in the following subsections.

4.1 Identification of Treatment Technologies for WAS Pretreatment

The BC team first identified possible WAS pretreatment technologies for incorporation at EWPCF. These are discussed below.

4.1.1 Ultrasonic Pretreatment

The principle of ultrasonic treatment relies on the cavitation generated by probes to disintegrate cell walls and reduce particle size, making WAS easier to digest during the anaerobic digestion process. There are a few commercial ultrasonic pretreatment technologies available, such as Sonix™ by Sonico and Sonolyzer™ by Ovivo.

The key components of these ultrasonic pretreatment technologies are similar, typically include a reactor, probes, and a control unit. A schematic depicting the key components of a Sonolyzer™ unit is shown in Figure 4-1.

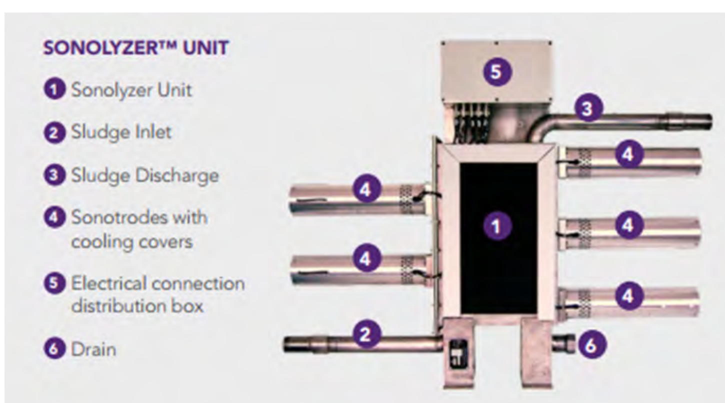

Figure 4-1. Schematic of key components of a Sonolyzer™ unit

Courtesy of Ovivo

Ultrasonic pretreatment technologies have been tested at bench scale and pilot scale and shown to increase volatile solids (VS) reduction and increase biogas production. However, no full-scale installation has been reported at the time of this evaluation.

4.1.2 Electrokinetic Disintegration

Electrokinetic disintegration technology uses high-voltage of electricity to rupture the cell membranes. Two electrokinetic disintegration technologies have been developed, including BioCrak® and OpenCEL™. The OpenCEL™ system is currently not available as the company filed for bankruptcy a few years ago.

BioCrack® is an electrokinetic disintegration process offered by Vogelsang. During the process, a high-voltage field is generated in the reactor, which breaks up organic matter and bacteria in WAS and makes it easier to digest during the anaerobic digestion process. A BioCrack® system consists of several modules. Each module is made up of three major components, including a housing, electrode, and electrode head, as shown in Figure 4-2. The number of modules in each system is determined by the characteristics of the sludge and digestion process.

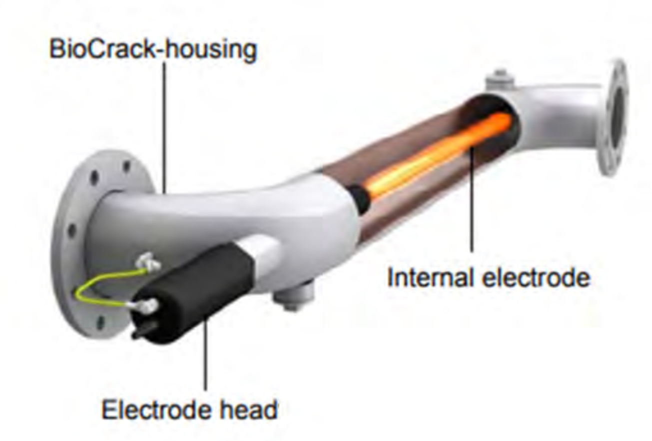

Figure 4-2. Section view of a BioCrack® module

Courtesy of Vogelsang

BioCrack® has more than 40 installations, most of which are in biogas plants for silage digestion in Europe. There is no reported municipal WWTP BioCrack® installation in North America.

4.1.3 Thermal Hydrolysis

The thermal hydrolysis process (THP) solubilizes the organic fraction of the sludge and break the cell membranes by submitting it to elevated temperature and pressure. Manufacturers of thermal hydrolysis systems include Cambi, Veolia (BioThelys™ and Exelys™), and Ovivo (LysoTherm™). Cambi, Biothelys, and Exelys were evaluated for processing both WAS and primary sludge, which is discussed in TM 2. Within this task, these technologies were evaluated for a WAS-only application.

The LysoTherm™ thermal pressure hydrolysis system is distributed by Ovivo in North America. It is a continuous process that uses thermal pressure for WAS pretreatment. Sludge is fed into the LysoTherm™ by means of a feed pump and pressurized between 5 and 10 bar. The sludge is then heated to 160 to 175 degrees Celsius (°C) using thermal oil and held at that temperature for 30 to 60 minutes. Sludge is then cooled and fed to the digesters. Recovered heat is used to preheat the incoming sludge flow. A schematic showing the process flow of the LysoTherm™ process is shown in Figure 4-3.

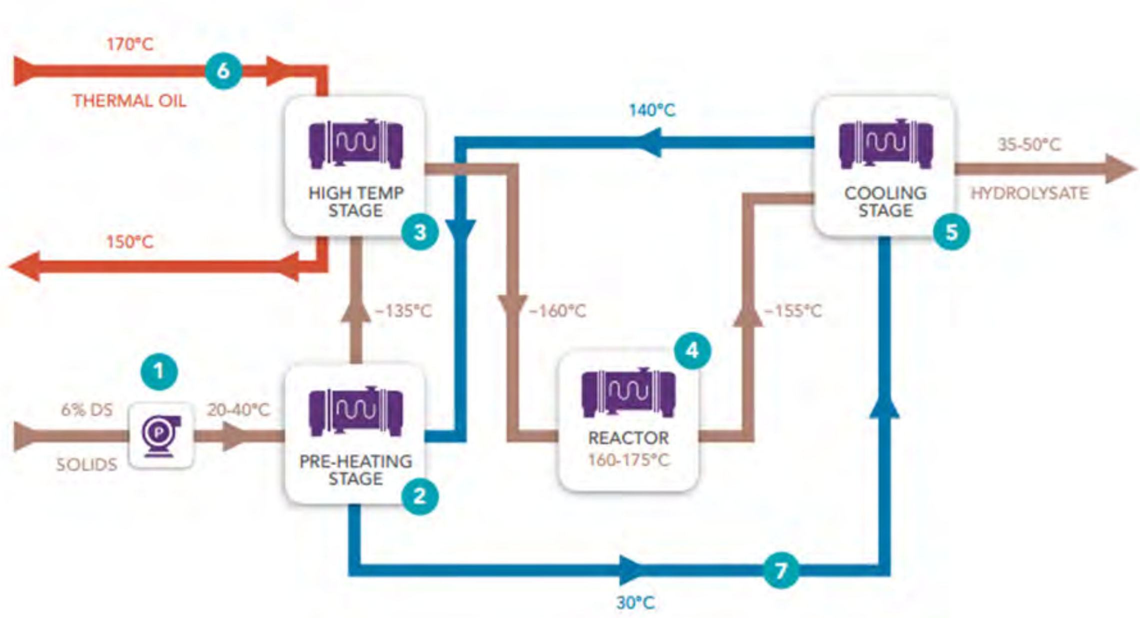

Figure 4-3. Schematic of LysoTherm™ process

Courtesy of Ovivo

The LysoTherm™ process has several full-scale installations in Europe but no reported installation in North America at the time of this evaluation.

4.1.4 Mechanical Pretreatment

Mechanical pretreatment technologies rely on high pressure and cavitation for cell destruction. The sludge is homogenized, pressurized, and forced through a nozzle, causing cell rupturing. Mechanical pretreatment systems include Crown™ Sludge Disintegration (Evoqua) and MicroSludge™ (Paradigm Environmental Technologies). The MicroSludge™ system is currently not available as Paradigm Environmental Technologies Inc. filed for bankruptcy a few years ago.

The Crown™ disintegration system is a mechanical WAS pretreatment process distributed in North America by Evoqua. The main principle is cavitation created by operating the system at 12 bar and pumping through a pressure reduction nozzle (the disintegrator). Cavitation occurs in the second part of the nozzle as a result of the sudden pressure drop. Key components of the Crown™ system include a homogenizer, disintegrator nozzle, pressurization pump, recirculation tank, and discharge pump. An installation of the Crown™ system is illustrated in Figure 4-4.

Figure 4-4. Crown™ disintegration system at Rosedale WWTP, North Shore, New Zealand

The Crown™ system has been installed in approximately 20 facilities, most of which are in Germany. No full-scale installation in North America has been reported at the time of this evaluation.

4.2 Fatal-Flaw Screening of WAS Pretreatment Technologies

The WAS pretreatment technologies presented in Section 4.1 were screened using four fatal-flaw criteria, which were applied uniformly across all technologies. The four criteria developed in conjunction with EWA staff include the following:

- **At least one successful North American installation of technology.** There must be at least one full-scale installation of the technology at a WWTP in North America.
- **At least one successful installation and operation in a facility of similar size.** The technology should be sufficiently developed that it is applicable at a facility of comparable size to EWPCF to ensure compatibility.
- **Available space.** The technology must be accommodated within the limited available footprint at EWPCF.
- **Compatibility with plant site and any existing equipment.** The technology must be capable of being integrated into the existing EWPCF infrastructure.

For an alternative to be considered for the ranking process, the alternative must pass all four fatal-flaw criteria. The fatal-flaw screening results are presented in Table 4-1.

Table 4-1. WAS Pretreatment Technologies Fatal-Flaw Evaluation

Technology	Technology Maturity	Successful Operation	Available Space	Compatibility
Sonolyzer™	Fail	Fail	Pass	Pass
Sonix™	Fail	Fail	Pass	Pass
BioCrack®	Fail	Fail	Pass	Pass
OpenCEL™	Fail	Fail	Pass	Pass
Cambi™: WAS only	Pass	Pass	Pass	Pass
Exelys™: WAS only	Fail	Pass	Pass	Pass

Table 4-1. WAS Pretreatment Technologies Fatal-Flaw Evaluation				
Technology	Technology Maturity	Successful Operation	Available Space	Compatibility
BioThelys™: WAS only	Fail	Pass	Pass	Pass
LysoTherm™	Fail	Fail	Pass	Pass
Crown™	Fail	Fail	Pass	Pass
MicroSludge™	Fail	Fail	Pass	Pass

4.3 Conclusions

Cambi™ THP is the only WAS pretreatment technology that passed the fatal-flaw screening. Other technologies failed because of lack of technology maturity and/or successful operation in North America. Cambi™ THP was evaluated as one of the solids stabilization technologies in TM 2 and was selected for further evaluation. It is important to note that in a WAS-only scenario, Cambi does not produce Class A biosolids. Nevertheless, WAS-only Cambi THP is being carried forward for further analysis.

Section 5: Increased Gas Production: Co-digestion

Another means of increasing gas production is via the importation of HSW, such as fats, oil, and grease (FOG) and pre-processed food waste. These wastes can be co-digested with sludge to increase biogas production and potentially digester performance. This opportunity is discussed in detail below.

Anaerobic digestion is currently at the nexus of two important State of California goals: organics diversion from landfill and increased renewable energy and fuels generation. Organics diversion from landfill is the primary initiative in the State's 75 percent solid waste recycling goal and is backed up by new regulations, which require source separation and collection of organics (Assembly Bill 1826 and Senate Bill [SB] 1383). The goal of SB 1383 is to reduce CH_4 emissions from landfill and further promote/require organics diversion (Short-Lived Climate Pollutants Act, California Air Resources Board). The primary alternatives for organics management are anaerobic digestion and composting—of which anaerobic digestion is the only process that offers energy recovery potential. Over the next few years, California's municipal solid waste haulers, material recovery facilities, and landfills will need to develop collections, processing, and energy recovery infrastructure to address these State legislations and goals.

Existing WWTPs are uniquely positioned to play a role in the new organics marketplace. Whereas waste management facilities do not typically have anaerobic digesters, most WWTPs already operate digesters (with energy recovery facilities) and may have additional capacity for organic wastes beyond municipal wastewater solids. In addition, WWTPs are generally able to effectively manage the digestate- and nutrient-rich residuals in a beneficial way. Many WWTPs are already using available digestion and energy capacity for co-digestion of FOG and liquid organic HSW from industry. Tipping fees for waste acceptance and increased DG production for energy generation make co-digestion economically viable and potentially attractive to public agencies operating WWTPs. Acceptance of organics diverted from landfills would follow the same model, but perhaps with improved economies of scale due to the large and steady demand created by the landfill/organics regulations.

5.1 Co-digestion Feedstocks and Typical Characteristics

There are three general categories of co-digestion feedstocks: 1) HSW and FOG; 2) source-separated organics (SSO)/food waste; and 3) the organic fraction of municipal solid waste (not SSO). FOG is already being received by EWA in a quantity of approximately 261,000 gallons per month. Recently, EWA has completed trials, collecting brewery waste and co-digesting it. As part of the planning process, EWA and the BC team have started discussions with local waste haulers about obtaining a pre-processed SSO.

This section describes the characteristics of the pre-processed food waste that would be anticipated for EWA's facility. The analysis assumes that EWA will continue to receive the same amount of FOG as it does now. However, for mesophilic digestion, there will not be enough capacity with the current configuration of using Digesters 4 through 6, therefore EWA would need to stop accepting FOG in the future. As FOG is a known feedstock and discussed in TM 1 as part of existing conditions, this section focuses mainly on the pre-processed SSO characteristics.

The pre-processed SSO is expected to range in solids concentration from 12 to 15 percent, and may vary in pH ranging from 3 to 7, with the expected pH value being around 5. As part of the development of the pre-processed SSO receiving program, it is assumed that EWA will develop standards for quality related to minimum screen size, debris removal rates, and presence/absence of manufactured inerts. Generation of the pre-processed SSO will be accomplished by a third party, off site. Raw SSO will be processed into an organic feedstock, nearly free of contaminants, pulped, extruded, and/or slurried into a pumpable liquid. Attachment C summarizes the SSO requirements that the Sanitation Districts of Los Angeles County (LACSD) has developed for its pre-processed SSO receiving program. Other pertinent requirements include recent requirements developed by CalRecycle under its new composting regulations (California Code of Regulations [CCR] Title 14, Chapter 3.1, Section 17868), which is included to provide some guidance on physical contamination requirements, which EWA may wish to incorporate (Attachment C). Viewed as a whole, these can be used as a guide for the desired feedstock quality for the partners that will provide EWA with pre-processed SSO.

5.2 Initial Estimation of Acceptable Co-Digestion Volumes

Estimation of acceptable co-digestion volumes was completed assuming existing sludge production values as well as 2030 project flows and loads. For these analyses, the amount of FOG was held constant at existing conditions at 8,700 gallons per day (gpd). The amount of acceptable co-digestion volumes was determined based on the process limiting factor, either hydraulic loading rate (HLR) or organic loading rate (OLR). For the initial estimates, only pre-processed SSO was considered, assuming at the lower end of the range at 12 percent total solids (TS) and 85 percent VS. Table 5-1 summarizes the existing and projected solids loadings.

Table 5-1. Summary of Annual Average Solids Conditions

Digestion Feedstock	Existing			2030		
	Flow (gpd)	%TS	%VS	Flow (gpd)	%TS	%VS
Primary sludge	140,282	4.1%	87%	179,596	4.1%	87%
TWAS	60,232	5.6%	80%	79,835	6%	80%
FOG	8,700	5.5%	80%	8,700	5.5%	80%
SSO		12%	85%		12%	85%

TWAS = thickened waste activated sludge

Furthermore, co-digestion capacity was analyzed under several conditions: mesophilic, thermophilic conventional, thermophilic 10-day, and THP. They were further analyzed with and without the small digesters, except for THP. The addition of the small digesters in each scenario provided additional capacity. The HLR and OLR were varied depending on the scenario reviewed. Table 5-2 provides the process values used for each of the stabilization scenarios.

Table 5-2. Process Data for Each Solids Stabilization Scenario

Condition	Digester Volume (MG) [a]	Digester Volume with Small Digesters (MG) [a]	HLR (d)	OLR (lb-VS/ft^3)
Mesophilic	4.1	5.0	15	0.18
Thermophilic: 15-day	4.1	5.0	15	0.35
Thermophilic: 10-day	4.1	5.0	10	0.35
THP	4.1	--	12	0.40

a. Digester volume assumes service conditions, meaning the largest is out of service.

lb-VS/ft^3 = pounds volatile solids per cubic feet; MG = million gallons.

The OLR and HLR (expressed as VS equivalent load) were determined based on the loading rate and total digester capacity. The available capacity was determined by taking the difference between the actual OLR and the maximum OLR (Table 5-2) for OLR process as well as the difference between the actual HLR and the minimum HLR (Table 5-2). These differences became the available capacity. The process limiting factor was determined based on which factor had less capacity. For instance, in 2030, THP was organically limited (120,000 pounds VS per day [lbs-VS/day]), meaning that there was more hydraulic capacity estimated (157,000 lbs-VS/day).

This organic loading equates to a volume of preprocessed SSO based on the assumed 12 percent TS and 85 percent VS. Assessing capacity under service conditions and peak month loads is a conservative approach that will evaluate the worst-case scenario (least amount of capacity). In addition to the conservative approach, a less conservative approach was evaluated and are presented below. The less conservative approach assumes that all digesters are online and the flows are under peak month conditions. Because these assessments are less conservative, there may be times when EWA would have to stop accepting FOG and SSO from the haulers. Both scenarios are presented because it allows EWA to make the decision, does EWA want absolute redundancy (first assessment) or have provisions in the contract allowing EWA to reject loads when these worst-case loads occur.

Based on historical, projected, and assumed data, an amount of SSO feedstock was determined based on peak month conditions (peaking factor of 1.23 was applied to annual average values). Assuming peak month configuration provides a conservative value for co-digestion feedstocks. Table 5-3 summarizes the capacity available for each of the stabilization scenarios.

Table 5-3. Results of Capacity Analysis Under Service Conditions [a]

Condition	Current		2030	
	SSO (gpd)	With Small Digesters SSO (gpd)	SSO (gpd)	With Small Digesters SSO (gpd)
Mesophilic	18,000	45,600	0	5,500
Thermophilic: 15-day	18,000	78,000	0	5,500
Thermophilic: 10-day	129,700	129,200	82,200	152,000
THP	166,500	N/A	140,600	N/A

a. *Assumes SSO solids content of 12% TS. b. Digester volume is 4.1 MG. c. Digester volume is 5.0 MG.*

As noted in Table 5-3 there is no capacity in the future for mesophilic digestion and 15-day thermophilic digestion. Under these conditions, there would not be enough capacity to treat the projected amount of sludge and FOG received under service conditions, unless Digesters 1 through 3, 5, and 6 are in service. Thermophilic operating in 10-day mode can accept approximately 82,200 gpd of SSO with only the two large digesters online. It can also accept 152,000 gpd with Digesters 1 through 5 online. This would result in an estimated biogas increase of approximately 1,100,000 standard cubic feet per day (scfd) and 2,100,000 scfd, respectively, assuming a biogas yield of 18 cubic feet per pound VS per day. Additionally, THP would yield an estimated biogas increase by 1,900,000 scfd from SSO.

Table 5-4 summaries the available capacity when all of the digesters are online under peak month conditions. These estimated capacities are less conservative and allows for acceptance of more HSW. Because all of the digesters (Digesters 1 through 6) are in service, as part of the contract with the waste haulers, stipulations need to be made for times when HSW cannot be received. As mentioned previously, the additional HSW results in additional gas production. Biogas production ranges from 1,000,000 scfd to 3,600,000 scfd additional biogas from SSO only.

Table 5-4. Results of Capacity Analysis Under Full Operational Conditions [a]

Condition	Current		2030	
	SSO (gpd)[b]	With Small Digesters SSO (gpd) [c]	SSO (gpd) [b]	With Small Digesters SSO (gpd) [c]
Mesophilic	78,200	103,600	50,900	76,400
Thermophilic: 15-day	154,700	214,700	82,200	142,200
Thermophilic: 10-day	242,500	292,000	215,200	264,700
THP	295,400	N/A	269,500	N/A

a. *Assumes SSO solids content of 12% TS.*

b. *Digester volume is 6.15 MG. c. Digester volume is 7.05 MG.*

Based on the above assessments and engineering judgement, it is recommended that Mesophilic could accept 30,000 gpd of SSO. Also, the 15-day thermophilic scenario could receive 50,000 gpd, while the 10-day thermophilic and THP scenarios would accept 80,000 gpd of SSO. These recommended values consider both assessments and are more conservative than the peak month assessment but not as conservative as the under-service condition assessments. These values also consider truck traffic. In the case of thermophilic 10-day and THP, the truck traffic was limited to 13 trucks per day (6,000-gallon trucks), which results in a limit of 80,000 gpd of SSO.

Finally, another area for concern with the addition of outside feedstocks is the potential for NH_3 toxicity. This is a concern especially with THP, when the amount of total NH_3 nitrogen (NH_3-N) is greater than 3,000 milligrams per liter (mg/L) (Gerardi 2003). Part of the co-digestion analysis reviews the amount of potential NH_3-N released during the digestion process. As historical data for NH_3 were not available, values were assumed for typical sludge NH_3 content. To provide a more accurate analysis of the soluble and total nitrogen content, primary sludge, TWAS, digester, and FOG samples should be analyzed for total Kjeldahl nitrogen and soluble NH_3 content. The total NH_3-N content may be an issue for THP at a 9 percent TS feed content. The NH_3-N content was 3,208 mg/L and 3,085 mg/L for THP under service conditions at peak month for current and in 2030, respectively. Under full operational conditions the NH_3-N values are higher at 3,358 mg/L and 3,276 mg/l for current and in 2030, respectively. Each of these conditions estimates NH_3-N greater than 3,000 mg/L. This could cause NH_3 toxicity issues in THP; however, additional samples should be tested to confirm estimated and assumptions used in these analyses. Additionally, the reduced amount of SSO recommended previously would also alleviate this issue. Attachment D presents the co-digestion model calculations and assumptions.

5.3 Results of Initial Outreach to Feedstock Providers

Part of the project work includes understanding how much SSO is available in the market, and if the waste haulers processing it would be interested in bringing the SSO to EWPCF. A meeting was set up in September 2017 with the three major waste haulers in the EWA service area: Waste Management (WM), Republic Services, and EDCO. Others present at the meeting included representatives from EWA and BC.

The agenda started with providing the waste haulers with background information regarding EWA's current operations and capacity considerations. The evaluation for selecting the best biosolids process for EWA includes confirming that waste haulers could fill the volume capacity of whichever final biosolids process was selected. The consensus from the waste haulers was that if the capacity was there, the waste haulers would bring the material.

The waste haulers were then given an opportunity to share their plans for handling SSO diversion as organics are required to be diverted from landfills. As could be expected, the representatives were hesitant to share their goals and strategies with their fellow competitors in the room. However, each waste hauler indicated that they would reach out to EWA individually post-meeting to discuss further.

EWA then used the meeting to confirm its commitment to increasing organics loads. EWA highlighted the potential for a mutually beneficial public-private partnership, which would result in a public win with regional development addressing emerging organics diversion requirements. Each waste hauler expressed gratitude to EWA for taking the initiative to start conversations regarding organics waste diversion, and each waste hauler indicated that it would reach out to EWA separately to continue that conversation.

Section 6: Digester Gas Management and Dryer Control

EWA's biogas production currently exceeds the permitted fuel input for the IC engines, even with the revised air permit (November 2017). Biogas to the engine is automated and controlled on pressure. Excess biogas is directed to the heat dryer. This practice makes use of the biogas and decreases NG purchase for the drying process. The control of biogas flow to the dryer is based on manual set points. In an effort to avoid drawing too much biogas to the dryer (and "starving" the engines), EWA operators typically set the dryer biogas flow rate lower than the actual available gas. As a result, some digester gas is wasted in the flare.

There are two solutions to this situation: 1) automate the dryer biogas flow; or 2) change the plant's approach to managing the set point. Automating the dryer biogas flow might take some additional SCADA programming and instrumentation, but most of the piping, valves and instruments are already in place. These programming upgrades should be considered for near-term implementation.

In the meantime, EWA can change its approach to the dryer biogas set point. Instead of setting a low flow, the plant can set a higher flow set point. The engines won't be "starved" if biogas production dips—the existing NG blending control scheme will kick in to maintain engine output. This overall approach would eliminate biogas flaring without increasing the plant's net purchase of NG.

Section 7: Conclusions and Next Steps

Enhancements to the biogas train have been evaluated in this task. Options to provide gas treatment and gas storage, and improve biogas production that passed the fatal-flaw filter, will be combined with selected technologies screened in Tasks 2 and 3 for the solids and biogas use process areas. Once the full set of alternatives are developed, they will be evaluated on a net present value basis for further screening.

References

Gerardi, Michael. *The Microbiology of Anaerobic Digesters,* John Wiley & Sons, Inc. Hoboken, NJ, 2003.

Noelte, Jeff. *Technical Memorandum – Evaluation of Alternative Fuel Digester Loading Strategy,* Trussell Technologies, 2017.

Attachment A: Workshop Meeting Minutes

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Meeting Minutes

Prepared for: Encina Wastewater Authority
Project Title: Energy & Emissions Strategic Plan & Biosolids Management Plan Update
Project No.: 150871

Purpose of Meeting: Workshop #3
Date: September 19, 2017
Meeting Location: Encina Wastewater Authority
Time: 12:30 – 4:00 PM
Minutes Prepared by: Jocelyn Lu, Brown and Caldwell

Attendees:
Debbie Biggs, Encina JPA
Doug Campbell, Encina, JPA
Jimmy Kearns, Encina JPA
Mike Steinlicht, Encina JPA
Octavio Navarrete, Encina JPA
Scott McClelland, Encina JPA
Tucker Southern, Encina JPA
Adam Ross, Brown and Caldwell
Hari Seshan, Brown and Caldwell
Jocelyn Lu, Brown and Caldwell
Scott Lacy, Brown and Caldwell
Scott Goldman, RMC

Attachments:

- Workshop #3 Presentation Slides

Decisions

The following is a list of decisions made as a result of the meeting discussion:

- BC will update conceptual layouts per discussion with EWA staff.

Action Required

The following is a list of actions required as a result of the meeting discussion:

- Scott L to send out an outlook invitation for a biweekly conference call for the Encina and BC team.
- Scott L to send list of additional data/document requests over to Scott M after updating based on discussion.
- Adam to reach out to Tom to get information regarding the mixing analysis.
- Scott L to send a WEFTEC list to Encina and get their input.
- Hari to review the mass balance calculations and provide an explanation.
- Adam to confirm the specific CAMBI model for thermal hydrolysis with Tom.
- Adam to set a call between Kenny Klittich (BC) and Tucker (EWA) to discuss energy options.

Summary

Workshop #3 was held for the Encina Water Authority (EWA) Energy & Emissions Strategic Plan & Biosolids Management Plan Update. The purpose of this Workshop was to review pending administrative tasks and provide task updates. A summary of the discussion is provided below:

Introductory Items

BC started off the meeting by reviewing the schedule and goals for the meeting. The goals are to generate content and direction for the project team moving forward.

- This month, the Brown and Caldwell (BC) team will be:
  - Working on and finalizing TMs 2 and 3.
  - In October and November, BC will be developing SWEET alternatives and providing more clarity on how the pieces interact.
- Scott Lacy (Scott L) states that since the next workshop won't be until December, he'll send out a biweekly conference call invite for the team.
- **ACTION: Scott L to send out an outlook invitation for a biweekly conference call for the Encina and BC team.**

Outstanding Data Requests

BC reviewed outstanding data requests with EWA. They included:

- Cogen and solids systems drawings and engine cut-sheets
- Engine O&M services, intervals, and costs
- Dryer system drawings and cut sheets
- Copies of current air permits (SDAPCD and Title V)
- CEPT electrical demand discrepancies
  - Requesting information on why the electrical demand for CEPT changed from 1067 kWh/month prior to 2/1/16. After 2/1/16 it was either less than 650kWh/month or zero
- **ACTION: Scott L to send list of additional data/document requests over to Scott M after updating based on discussion.**

There was a subsequent discussion on the heat dryer in the building. Mike Steinlicht (Mike) states that the dryer is in a steel fabricated building (not a brick and mortar), so there is opportunity there to expand the building to put in a second dryer.

Report Out on Meeting with Waste Haulers

BC met with the waste haulers earlier the same day. Below is a summary of the report out from the team. For the full minutes, please see the minutes for the Waste Haulers meeting.

- The waste haulers present at the meeting included representatives from Waste Management (WM), Republic Services, and EDCO.
- Scott M states that the question was posed to the waste haulers on how much organic food waste they could bring to the plant, and the consensus was that if the capacity was there, they would bring the material.
  - Adam Ross (Adam) agreed and stated that Encina will want to think about how much cushion they'd want to give themselves, and that should be taken into consideration on the volumes given to the waste haulers.
- There was also a discussion regarding vehicle fuel with the waste haulers.

  - Adam presented 3 options to distribute vehicle fuel: (1) fueling station, (2) tube trailers, and (3) injecting it straight into the pipeline.
  - 2 out of the 3 haulers expressed hesitation with on-site vehicle fueling.
  - Adam states that when evaluating vehicle fueling in the SWEET model, the RIN credit would be discounted in terms of value and/or duration (leading to a more conservation evaluation).
  - Scott L states that it would make sense to develop a range of capacities for the vehicle fueling option, to support both internal evaluation and provide a range for the haulers.
- Scott M asks if BC would want to be involved in the conversations with the haulers. Adam states that BC is interested, but to not let it delay a convenient meeting.
- Encina is beginning a food waste receiving pilot with Waste Management. WM is currently delivering 10,000 gallons per day, which will increase to 15,000 gpd over the next week.
  - Deliveries are reported as 14% solids and no major issues so far

Report Out on Anaergia Meeting

BC and Encina provided an update on their respective discussions with Anaergia.

- Adam states that Anaergia is trying to find ways to secure dried cake from other sources in addition to bringing their own food waste and organics. Anaergia's Rialto facility is grant funded for pyrolysis demonstration, so they need to show proof of concept. If Encina was to give their dried cake to Anaergia, Encina would be paying Anaergia around $50/ton.
- Anaergia's only completed installation is in Victorville. There are other installations planned in the US, but they're either in design or construction.
  - There are installations in Europe, but they're all on small digesters. BC's concern is putting Anaergia mixers on a 2 M gallon tank. However, putting the mixers on the smaller tanks may be a good fit.
- Mike states that Anaergia had previously provided them a quote on their equipment, and Anaergia was willing to give Encina a discount. Mike states that rehabbing one of the small digesters and installing an Anaergia mixer on it may be a small-scale project that can be started earlier.
- There was also a discussion on the potential consequences of starting and stopping mixers.
  - Adam states that there is potential for rapid rise to occur if you stop mixing.
  - Scott Goldman (Scott G) states that that hasn't historically been a problem at Encina.
  - Adam states that he'll reach out to Tom Chapman (Tom) to get his input on the mixing analysis.
- **ACTION: Adam to reach out to Tom to get information regarding the mixing analysis.**

Planning for WEFTEC

Individuals from both BC and Encina will be at WEFTEC in October. There is a plan to meet Monday afternoon to walk the floor and talk to vendors together.

- **ACTION: Scott L to send a WEFTEC list to Encina and get their input.**

Review of Mass Balance and Project Flows and Loads

BC reviewed the changes to the mass balance and projected flows and loads from the last Workshop.

- The mass balance was updated from the previous Workshop by back-calculating from historical pellets and class B cake data.
  - Scott G asks why the slope of the projections from the 2016 PMP didn't match the slope of BC's calculated projections.
  - **ACTION: Hari to review the mass balance calculations and provide an explanation.**
- Peaking factors for maximum 2-week and maximum week conditions were proposed based on historical data.

Codigestion Planning Assumptions

BC reviewed the codigestion planning assumptions:

- BC will prioritize the high-yield, low contamination feed stocks and leave remaining capacity for food waste.
- Under the mesophilic alternative, Encina will need to rehabilitate small digesters to allow for additional codigestion.
- In some scenarios, it's possible to demo some of the small digesters to build a receiving station.
  - Jimmy Kearns (Jimmy) states that the old maintenance building can be demo'd.
- Adam states that the current system is limited by the organic loading rate.
  - Mesophilic digestion could take about 20,000 gpd of food waste in addition to the current delivery volumes of FOG and brewery waste, but as the loads increase, small digesters would have to be brought online.
- For thermophilic digestion, you could take 22,000 gpd forecasted out to 2030 in addition to the current delivery volumes of FOG and brewery waste. However, this is limited by the hydraulic residence time.
- However, Encina could opt for a 10-day residence day (instead of the current 15-day), and then Encina could take 92,000 gpd through 2030.
  - East Bay MUD was approved by the EPA to go down to a 10-day hydraulic residence time while operating at 120 degrees.
- Scott G states that the SWEET model should take into consideration recycle streams, ammonia, and the associated increased energy demand from the aeration process. Impacts to a future nitrification process should be considered.

Screening of WAS Pretreatment Technologies

BC reviewed the screening of WAS pretreatment technologies:

- The only technologies that passes the fatal flaw filter were CAMBI thermal hydrolysis (WAS only) and Orege SLG.
  - Tom may want to show Encina Orege at WEFTEC.

Review of Biogas Train Enhancements

BC reviewed the screening of biogas train enhancements:

- Biogas Treatment Alternatives
  - Both gas conditioning and exhaust treatment pass the fatal flaw filter.

- They also both pass the evaluation criteria (greater than a score of 4.0), and so both alternatives will be evaluated in the SWEET model.
- Biogas Storage Alternatives
  - Dual-membrane gas holders pass the fatal flaw filter and may be a good option for the smaller tanks. Membranes are a good solution if you need gas storage and digester coverage. However, if just used as gas storage, it's not the best option because it's just a passive storage option, and it's hard to measure how much gas is in the system.
    - However, it is easier to add on older tanks because it's not as heavy as steel covers, and the dual membrane cover is compatible with Anaergia mixers.
  - The dedicated gas holder fails the fatal flaw filter because it's a new 50-foot diameter tank that Encina would need space for.

Air Permitting Impacts on Project

BC provided an update on where the air permitting process was for the project:

- Don King (Don) has submitted a BACT evaluation to the air district. The current BACT, which includes selective catalytic reduction (SCR), is not cost effective.
- Air district has responded with the question about what the "next best" threshold would be, and Don is currently preparing a response.
- Don will be submitting his final response to air permitting within the next couple of days.

Conceptual Alternatives

Thickening Alternatives

BC reviewed the thickening alternatives with Encina. The alternatives include:

- Mesophilic with the existing thickening scheme (rehab DAFTs)
- Mesophilic with RDTs
- Thermophilic with existing thickening scheme (rehab DAFTs)
- Thermophilic with RDTs
- Thermal Hydrolysis Process (THP) with RDTs

Generally, more efficient thickening provides more digestion capacity and efficiency.

Stabilization and Dryer Alternatives

BC reviewed the stabilization and dryer alternatives with Encina. The alternatives include:

1. Mesophilic and RDTs, with only one dryer, create Class B cake to land applications
2. Same as #1, but with two dryers
   a. You wouldn't have any Class B cake going offsite.
3. Thermophilic and RDTs, with only one dryer, create Class B cake to land applications
4. Same as #3, but with two dryers
5. Start with #4, but move to an aggressive 10-day thermophilic option with two dryers
6. "Class B" THP (WAS only), Class B cake to land applications
   a. The dryer would still be used, but anything additional would go to land application.
7. Class B THP, with two dryers
   a. There's a lot of capital cost here, so probably won't be feasible.
8. Class A THP, with only one dryer

a. This would create a Class A product.
b. Most THP facilities don’t have a dryer because they’re confident that people would want that Class A cake.

The options with the most codigestion capacity is Option #5, then #3, #4, and then #8. RDTs would provide more hydraulic capacity, which would change the limiting factor to dryer capacity. Scott G states that the current county litigation may force all facilities to produce Class A cake.

Review of Thermophilic Process and Conceptual Layout

BC reviewed the pros and cons of the thermophilic process, and then reviewed the conceptual lay-out.

- Thermophilic operates at a higher temperature, within a range of 120 - 140 Fahrenheit.
- There is a higher organic loading rate, and the process is stable at 10-day HRT. There also wouldn’t need to be a significant change in operations to implement.
- Review of the conceptual layout (Slide 38):
  - Where the heat exchangers are proposed, the gap there needs to be preserved. The gap is just big enough to let a vehicle through.
  - The location for the RDTs is okay.
  - The red box for the second dryer is currently pushing beyond the limits of the existing building. The existing wall may need to be pushed out to make room for a second dryer. The red box is pushing out over the existing DAFTs, which wouldn’t be needed anymore in this alternative.
  - The green box notes the receiving area. This location isn’t preferred because it’s farther from the digesters and closer to the admin building.
  - The magenta box is the blend tanks. These are optional, but nice to have. The current location is problematic because it blocks the roadway in an area with high truck traffic. Another potential location to put it is south of cogeneration.
- EWA notes that the annex and old maintenance can be demolished if necessary.

Review of Thermal Hydrolysis and Conceptual Layouts

BC reviewed the pros and cons of the thermal hydrolysis process, and then reviewed the conceptual layouts:

- Thermal hydrolysis would require the addition of new equipment, including: sludge screening, centrifuge pre-dewatering, steam, and a Class A THP process.
  - **ACTION: Adam to confirm the specific CAMBI model with Tom.**
- The end-product would be Class A with all streams being sent through the Class A THP process.
- Review of Conceptual Layout 1 (slide 40):
  - Most of the layout is in the area where the three smaller digesters are.
  - EWA staff state that that area is very busy, and construction sequencing would be tough. This wouldn’t be an ideal layout.
  - The receiving area (green box) represents an expansion of the current receiving facility. There’s potential to reconfigure the existing receiving area for more capacity.
  - Adam states that the main process units that need to stay together are the pre-watering building, cake storage, and THP process. Other units, like the electrical building, could go anywhere.

  - EWA staff proposed moving most of the equipment to where the old maintenance building currently is. They state that the building next to the old maintenance building, called "The Shop" is also available for repurposing. "The Shop" is a nice, high ceiling building that can repurposed for new equipment.
  - Prior evaluations suggested that the THP process could be located within the existing dryer building.
- Review of Conceptual Layout 2 (slide 41):
  - Most of the equipment in this layout is moved from the three small digesters area to where the existing DAFTs are.
  - EWA staff proposes to move the receiving area (green box) to the current old maintenance building and Shop area. However, they note that there are a lot of large utilities in that area.
  - Octavio Navarrete (Octavio) asks if there's a way to put the new electrical building closer to the existing MCC. There's some space next to the MCC, where DAFT 3 currently is. If DAFTs will be demolished, there is potential to put the new electrical building there.

Codigestion Alternatives

- BC will review codigestion with all the stabilization alternatives.
- BC will also analyze the cost benefit of bringing the small digesters online.

Digestion Alternatives

- BC will compare the belt filter presses and centrifuges to stabilization alternatives.

Power Production Alternatives

BC reviewed the power production alternatives and conceptual layouts:

- All the power production will be paired with a thermophilic digestion baseline for comparison. The best performing power production alternatives will then be combined with the best performing stabilization alternatives in the second round of analysis.
- BC will see a range of gas production, and that range will be taken into consideration in the evaluation.
- Reviewed Conceptual Layout: Engine – Gas Conditioning + Exhaust Treatment (slide 47):
  - In the upper left-hand corner (north of the small digesters), there are some agency manholes that can't be blocked.
  - EWA staff proposes to move the gas conditioning (orange box) slightly east, and replace the existing equipment there.
  - For the exhaust treatment, relocation of the existing equipment would be necessary.
- Reviewed Conceptual Layout: Microturbines with Gas Conditioning (slide 48):
  - The microturbines is a small shipping container, and it would be located wherever the gas conditioning is.
  - Adam explains that microturbines would only be used if EWA's existing permit can't be modified, and if it's not cost effective to do SCR.
- Reviewed Conceptual Layout: Digester Gas Upgrading – Pipeline Injection (slide 49):
  - This alternative would require a slightly bigger footprint, and separation equipment would be added to wherever the gas conditioning equipment is.
  - EWA states that the annex area could be used for gas conditioning.

  - EWA informs that the current gas pipeline that feeds the facility operates at 60 – 65 psi. There is a big one on Avenida Encinas that's 100 psi.
- Reviewed Conceptual Layout: Digester Gas Upgrading – Vehicle Fuel (slide 50):
  - Adam states that there's no room on-site to place a vehicle fueling station. That's why the conceptual layout has the vehicle fueling station south of the facility.
  - Scott M states that SANDAG is interested in building compressed natural gas (CNG) facilities in San Diego. On the bottom left corner of the figure, you can see the turn-out into the transit system parking lot. That could be a convenient location for a transit fueling station.
    - Tucker Southern (Tucker) states that EWA has been approached by Volkswagon to build a fueling station because they're required to spend $100 million.
- Reviewed Conceptual Layout: Small Scale Solar PV (slide 51):
  - The current layout proposes putting the small-scale solar PV panels over the primaries. EWA states that they don't like it over the primaries. It would be better over the aeration basins; however, EWA had already gotten a quote for that, and it wasn't cost effective.
  - Adam states that if cogeneration is maxed out, solar would be unnecessary.
  - Mike states that member agencies will have questions regarding solar, so BC should come prepared with numbers.
- Reviewed Conceptual Layout: Large Scale Solar PV (slide 52):
  - EWA staff states that the southern parcel is 28-acre's total.
  - The current box (purple) drawn for large scale solar PV could be moved farther north to match up with the fence line.
  - EWA staff proposes the equalization (EQ) basins as potentially a good place for solar, and it would keep the algae levels down.
  - BC and EWA discussed the possibility of virtual net metering:
    - EWA is in a position where they may produce more power than they use, which they would then export to the grid. Mike asks if there's a way to sell excess power to their member agencies, and only pay a transmission fee (not have to buy back the power from SDG&E).
    - Tucker states that SDG&E has a requirement where properties must be joined to share meters.
    - Mike states that EWA should know what the loads are from the member agencies, so they could have an "member agency demand" value.
  - **ACTION: Adam to set a call between Kenny Klittich (BC) and Tucker (EWA) to discuss energy options.**
- Reviewed Conceptual Layout: Dual Membrane Gas Storage (slide 53):
  - The dual gas membranes would be added atop the 3 smaller digesters.

Grant Updates

Adam provides an update on potential grants applicable to the project:

- There are no current advertisements for grant funding. There are some for batteries, but none for organics.
- BC is continuing to track the EPA's RIN quotas and determining what the values would be for codigestion.
- Mike states that EWA has elected officials that are interested in grants, and EWA should take the leadership in that arena.

Look Ahead and Wrap-Up

BC and EWA staff end the workshop with a look ahead:

- BC will schedule a webinar to present initial SWEET results in late October.
- Adam states that BC has developed a solids and energy baseline. However, BC still needs the current cost of operations, which will be part of the next data request.
- For Workshop 4, BC will have started some SWEET analysis, but the workshop will be focused on receiving feedback on assumptions and inputs. That feedback would then be used to finish the TM.
- During Workshop 5, BC will review the SWEET model results and present conclusions.

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Energy & Emissions Strategic Plan & Biosolids Management Plan Update

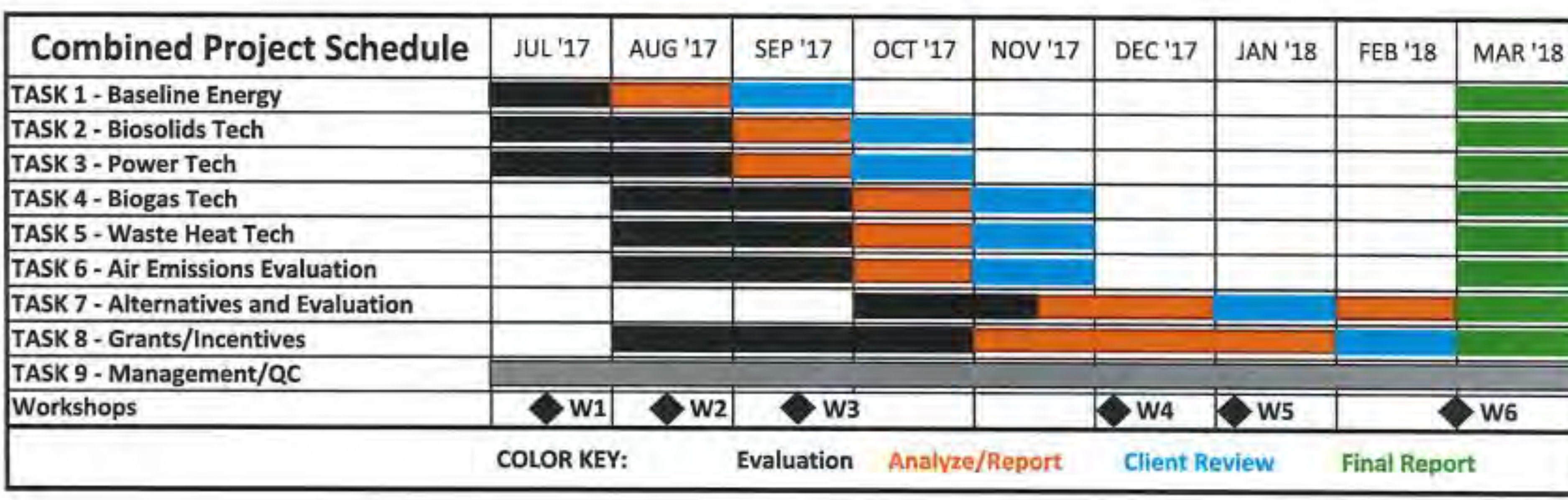
ENCINA WASTEWATER AUTHORITY

Workshop #3 – September 19, 2017

Encina Water Pollution Control Facility

Project Schedule

- Progress on schedule
- TM 1 submitted
- Other Tasks are under way
- Workshop #3 today



Agenda

- Administrative (30 min)
  - Status of data requests
  - Report out on waste hauler meeting
  - Report out on call with Anaergia
  - Review of WEFTEC schedule
- Confirm Final Mass Balance and Projected Flows and Loads (15 min)
- Presentation and Discussion on Codigestion Assumptions (20 min)
- Presentation and Screening of WAS Pretreatment Considerations (15 min)
- Review of Biogas Train Enhancements (30 min)
- Review Air Permitting Impacts on Project (30 min)
- Presentation of Conceptual Alternatives (60 min)
- Grants Update (10 min)
- Wrap-Up/Review Action Items (10 min)

New Data Requests

- TBD

Outstanding Data Requests

- Cogen and solids systems drawings, engine cut sheets
- Engine O&M services, intervals, and costs
- Dryer system drawings and cut sheets
- Copies of current air permits (SDAPCD and Title V)
- CEPT electrical demand discrepancies

Report Out on Waste Hauler Meeting

- Waste hauler meeting held this morning
- Goals:
  - Provide background info to haulers about EWA's goals and BEE effort
  - Determine availability of pre-processed food waste, market demand for an EWA initiative to receive more material, tipping fee range for SWEET analysis
  - Gauge interest in a renewable CNG partnership
  - Discuss "next steps" such as letter of intent, future coordination

Report Out on Call with Anaergia from 8/29/17

- Pyrolysis project in Rialto is interested in dried cake
  - Anaergia starting to consider contracts to secure product
  - Have not determined a tipping fee. Estimate around $50/ton range.
  - There may be an opportunity to influence a tipping rate for Encina if we get in early.
- Rialto facility will also accept dewatered cake
  - Dewatered cake target around 25% TS

Report Out on Call with Anaergia from 8/29/17

- UTS mixing system and Omnivore
- One installation in the US (Victorville, CA)
- Other installations planned in US (in design or construction)
- Several installations in Europe (on digesters less than 200,000 gal)
- Dialogue with Anaergia is ongoing
- Food waste pre-processing:
  - Orex or Biorex for food waste pre-processing

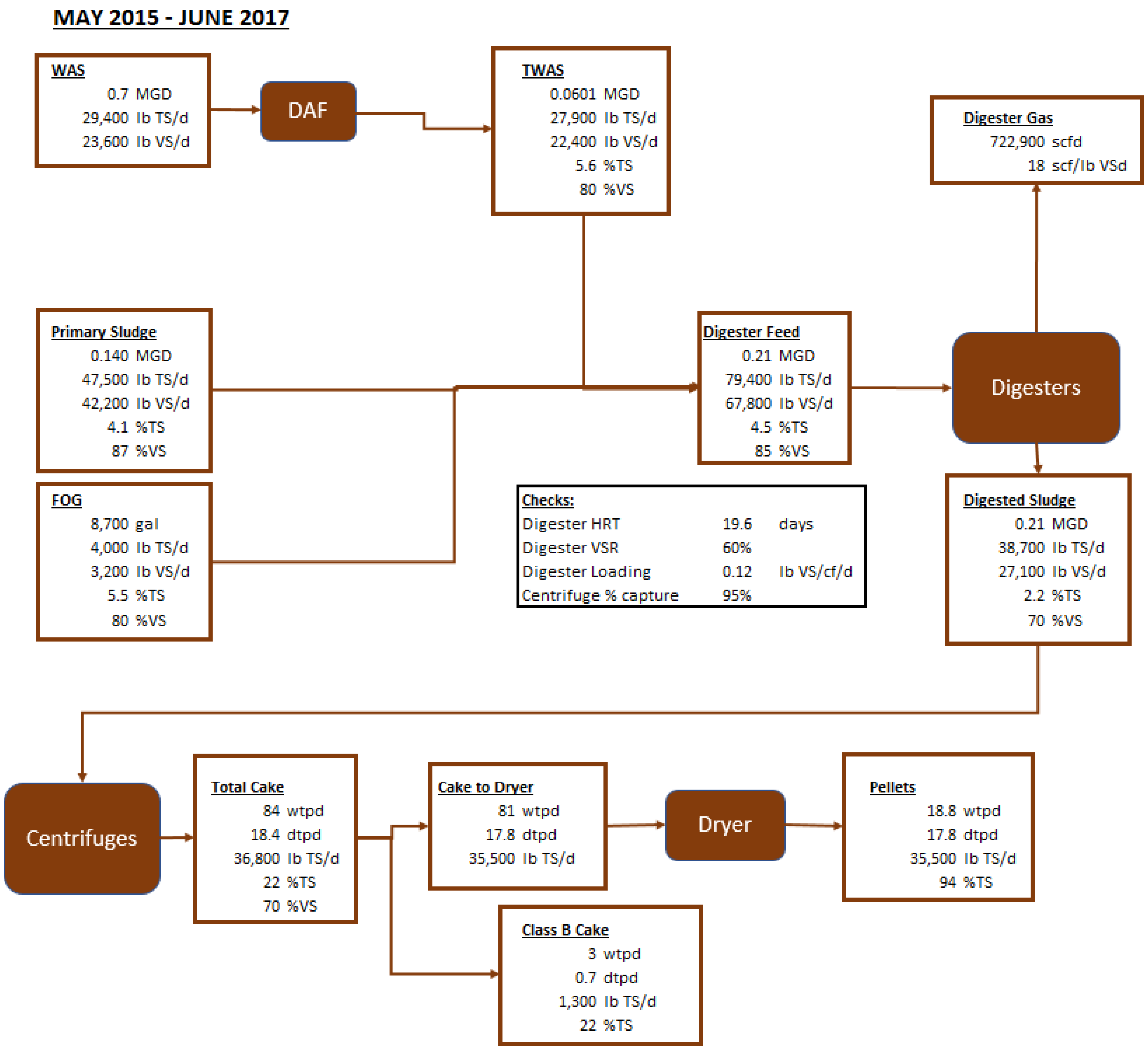
UTS Mixer Access Hatch

Omnivore recuperative thickener

Discussion on WEFTEC Schedule

Mass Balance and Projected Flows and Loads

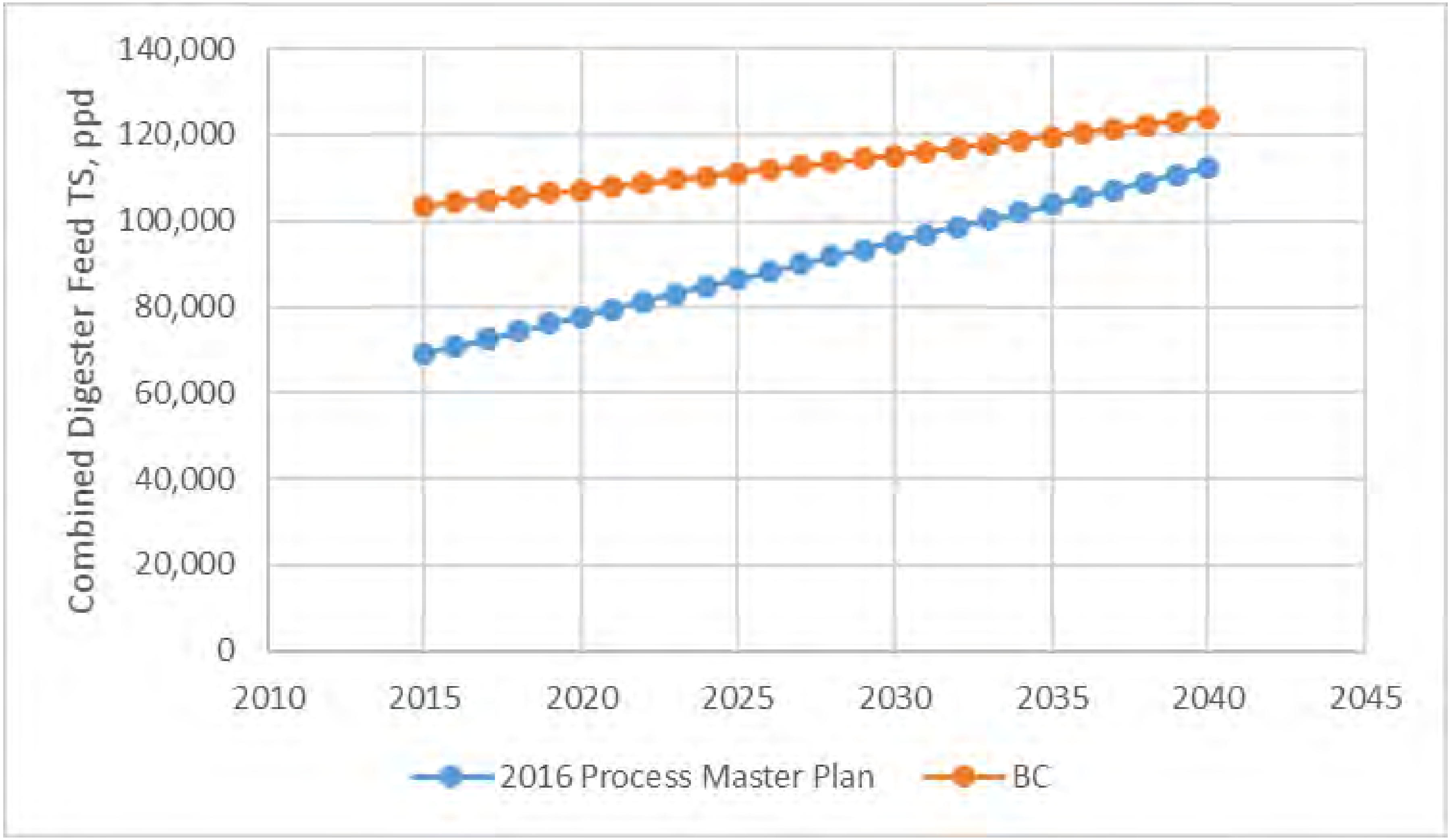
Mass Balance



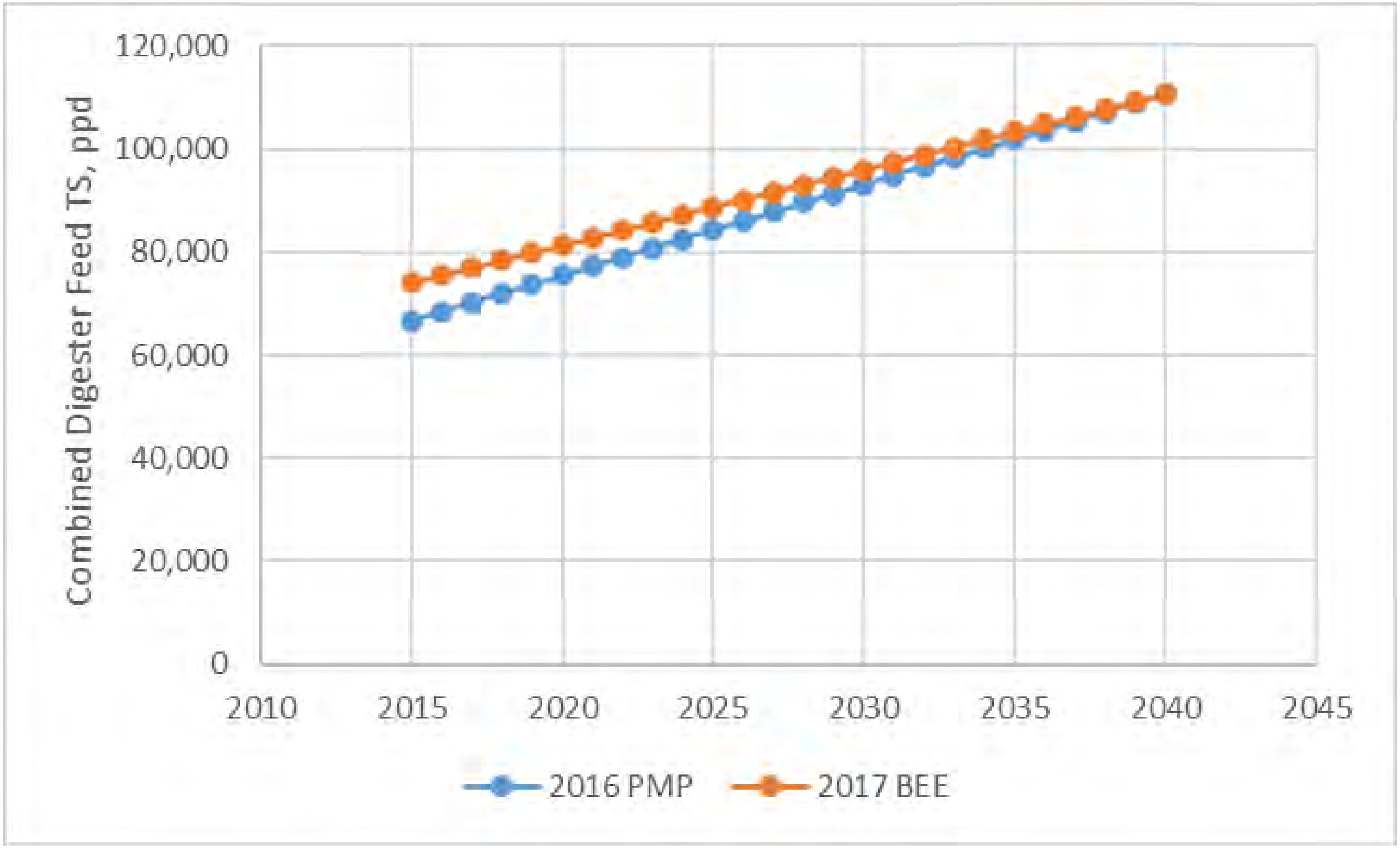
Mass Balance Assumptions

- The mass balance was determined using backward calculation based on historical data from pellets and class B cake. The Class B cake data were averaged with zero data to obtain an annualized daily average
- The centrifuge had an assumed percent capture rate of 95%.
- The VSR was 60% based on Van Kleeck, mass balance and engineering experience.
- WAS flows and loads were calculated based on historical data. TWAS was determined assuming percent capture rate of 95% for the DAFTs.
- FOG data were a daily average of the volumes received. This assumes FOG is fed 24/7/365. Assumes %TS and %VS are 5.5% and 80%, respectively.
- The primary sludge load was assumed to the difference of the sum of digester feed with TWAS and FOG load help constant.

Solids Mass Balance Comparison



Solids Mass Balance Comparison (Updated)



Sludge Production Peaking Factors

	Max Month	Peak 2-Week	Peak Week	Peak Day
Primary Sludge	1.23	1.3	1.4	1.60
WAS	1.23	1.3	1.4	1.60
Combined Sludge	1.23	1.3	1.4	1.60

Notes:

- Peaking factors for maximum month and peak day conditions are developed based on 2016 PMP solids projections.
- Peaking factors for maximum 2-week and maximum week conditions are proposed based on historical data.

Power Loads and Gas Usage

- Power:
  - Monthly production: 1,507 kW (2, 750 kW engines full output – 83% of total electrical demand)
  - Monthly import: 319 kW equivalent (1,390 MWh per year)
- Digester gas:
  - Average production: 1,580,000 therms per year
  - Engines: 1,234,000 therms per year
  - Waste gas: 160,000 therms per year
  - Heat dryer: 99,000 therms per year
- Natural gas: 696,000 therms per year
  - Engines: 116,000 therms/year
  - Other plant use: 580,000 therms/year

Codigestion Planning Assumptions (Task 4)

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Items for Discussion in Codigestion Analysis

- Will look at prioritizing high-yield, low contamination feedstocks and leaving remaining capacity for food waste
- Under mesophilic scenario, need to rehabilitate small digesters to allow additional codigestion
- Pros and cons of separate food waste digestion in small digesters
- Under other scenarios, possible to demo some of the small digesters to build a receiving station
- Analyzed scenarios up through 2030 loads

Initial Feedstock Analysis

- Current system limited by organic loading rate
- Mesophilic digestion could take about 20,000 gpd of food waste but as loads increase, need to bring small digesters on line.
- 15-day thermophilic digestion could take 22,000 gpd of food waste but is limited by hydraulic residence time
- Can opt to move towards 10-day thermophilic operation (EBMUD), which allows up to 92,000 gpd through 2030

Screening of WAS Pretreatment Technologies (Task 4)

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Fatal Flaw Filter

- Applied uniformly across all technologies
- Four criteria:
  - At least one successful North American installation of technology
  - At least one successful installation in a facility of similar size
  - Available space
  - Compatibility with plant size and any existing equipment

WAS Pre-Treatment Technologies Analyzed

- Sonolyzer: Sonication cell lysis
- BioCrack: Electrokinetic cell disintegration
- Lysotherm: Temperature and pressure hydrolysis using thermal oil
- Crown Disintegration: Pressure release disintegration
- OpenCEL: Electric focused pulse disruption. Bankrupted
- Microsludge: High pressure cell disruption. Bankrupted
- WAS Only Cambi*: Thermal hydrolysis WAS only
- Orege SLG Solution: compressed air addition upstream of digestion

WAS Pre-Treatment Technologies – Fatal Flaw

	Technology Maturity	Successful Operation of Comparable Size	Available Space	Compatibility
Sonolyzer	Fail	Fail	Pass	Pass
BioCrack	Fail	Fail	Pass	Pass
Lysotherm	Fail	Fail	Pass	Pass
Crown Disintegration	Fail	Fail	Pass	Pass
OpenCEL	Fail	Fail	Pass	Pass
Microsludge	Fail	Fail	Pass	Pass
Cambi Thermal Hydrolysis – WAS only	Pass	Pass	Pass	Pass
Orege SLG	TBD	TBD	Pass	Pass

Review of Biogas Train Enhancements (Task 4)

Biogas Treatment Alternatives

	Technology Maturity	Successful Operation	Available Space	Compatibility
Gas Conditioning	Pass	Pass	Pass	Pass
Exhaust Treatment	Pass	Pass	Pass	Pass

Biogas Treatment Alternatives

	Gas Conditioning	Gas Conditioning +Exhaust Treatment
Proven Technology Performance	5	4
Minimize Life Cycle Costs	3	4
Energy/Resource Recovery	4	5
O&M Impacts	4	3
Environmental Impacts	3	4
Community & Stakeholder Impacts	4	5
Project Site Compatibility	5	4
Weighted Score	4.05	4.25

Biogas Storage Alternatives

	Technology Maturity	Successful Operation	Available Space	Compatibility
Dystor type double membrane gas holder	Pass	Pass	Pass	Fail
Dedicated gas holder	Pass	Pass	Fail	Pass

Air Permitting Impacts on Project

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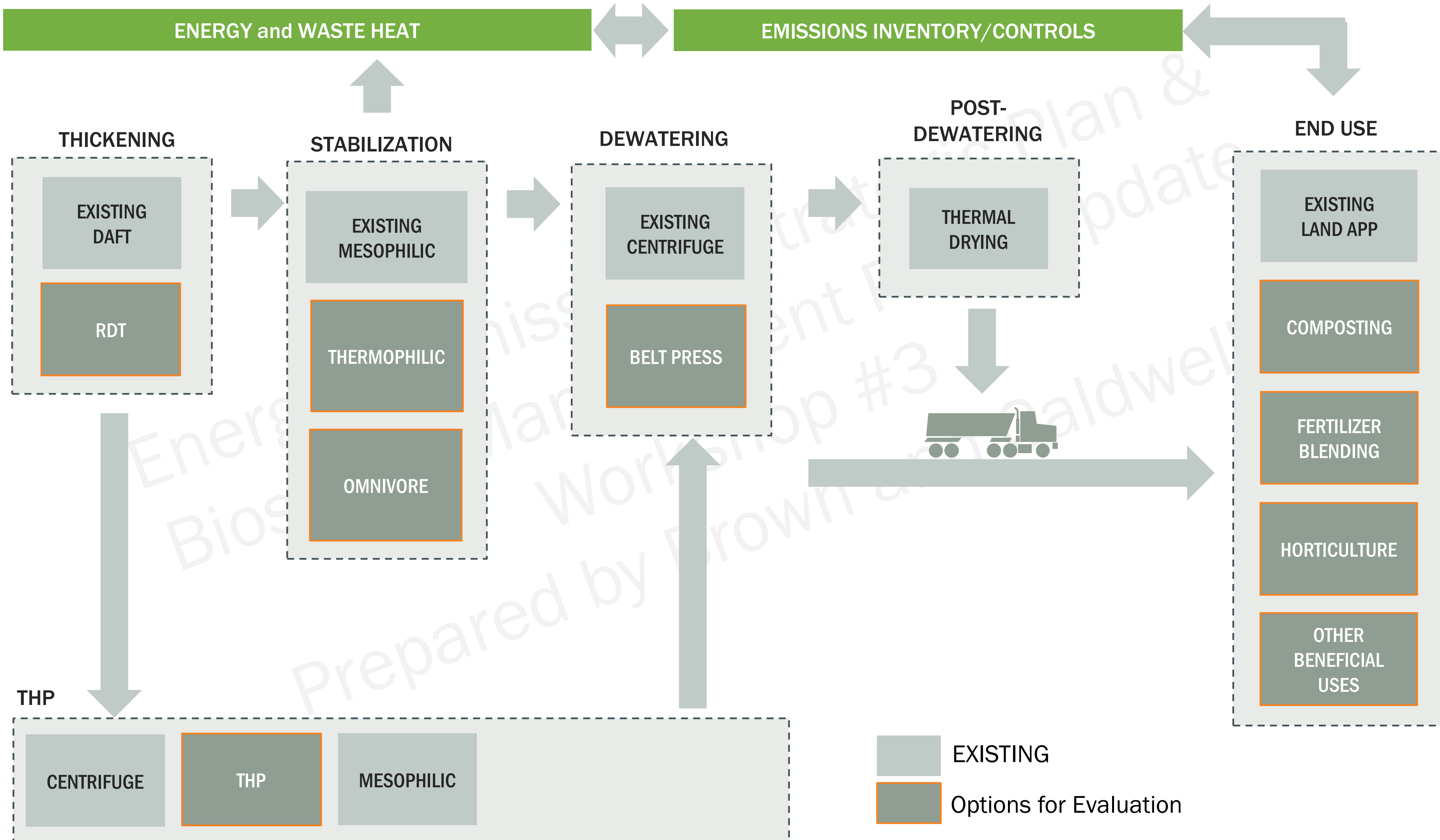
EWA is actively pursuing air permit modification

- EWA (with Don King) submitted a request for permit modification
- Current BACT (requiring SCR) not cost effective
- The air district responded with question about "next best" threshold – EWA (with Don King) preparing a response
- Goal is to adjust the CO emission rate from 530 ppm to ~400 ppm, and thereby adjust the fuel input limit aimed at keeping CO emissions below Title V synthetic minor threshold
- If successful, this effort would increase permitted cogen capacity by ~20%
- This increase would allow EWA to meet plant electricity demand with current digester gas flows and cogen system

Conceptual Alternatives

Evaluating Technologies and Markets Together



Thickening Alternatives

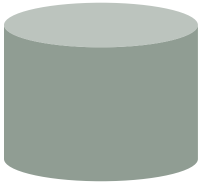
- Mesophilic and existing thickening scheme (rehab)
- Mesophilic and RDTs
- Thermophilic and existing thickening scheme (rehab)
- Thermophilic and RDTs
- Cambi and RDTs

Generally, more efficient thickening provides more digestion capacity and efficiency

Stabilization and Dryer Alternatives

1. Mesophilic and RDTs, one dryer, Class B cake to land app
2. Same as #1 but with 2 dryers
3. Thermophilic and RDTs, one dryer, Class B cake to land app
4. Same as #3 but with 2 dryers
5. Maximize codigestion – Aggressive (10-day) Thermophilic, two dryers
6. “Class B” Cambi, WAS only, Class B cake to land app
7. Class B Cambi with two dryers
8. Class A Cambi, only one dryer

Mesophilic



Features

- Operates at 95-100 ^{O}F
- Requires 15-day HRT/SRT to comply with Process to Significantly Reduce Pathogen (PSRP, EPA part 503)
- Organic loading typically limited to 0.18 lbs. VS/cf-day
- Produces Class B biosolids

Pros and Cons

- Pros:
  - Simple to operate
  - Lower energy demand than other processes
  - No additional footprint needed
- Cons:
  - Limited capacity to accept high strength waste; would need to rehab small digesters to accommodate other feedstocks
  - Current end use markets limited to regional compost or bulk agriculture in Arizona

Thermophilic

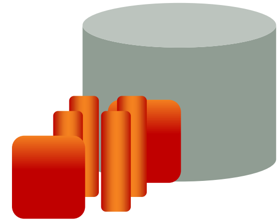
Features

- Operation at ~135^{O}F
- Can be stable at 10-day HRT based on organic loading limitation of 0.35 lbs. VS/cf-day
- Minor improvement in process VSR and gas production
- In proposed configurations, generates Class B biosolids

Pros and Cons

- **Pros:**
  - Comparable operation to mesophilic; no significant operational change necessary
  - Higher allowable OLR provides capacity for acceptance of high strength wastes
- **Cons:**
  - Current end use markets limited to regional compost or bulk agriculture in Arizona

Thermal Hydrolysis



Features

- Requires addition of new equipment:
- Addition of Sludge Screening
- Addition of Centrifuge Pre-Dewatering
- THP – Will assume Cambi B6-4(s)
- Requires steam
- Produces Class A with all streams sent through Cambi

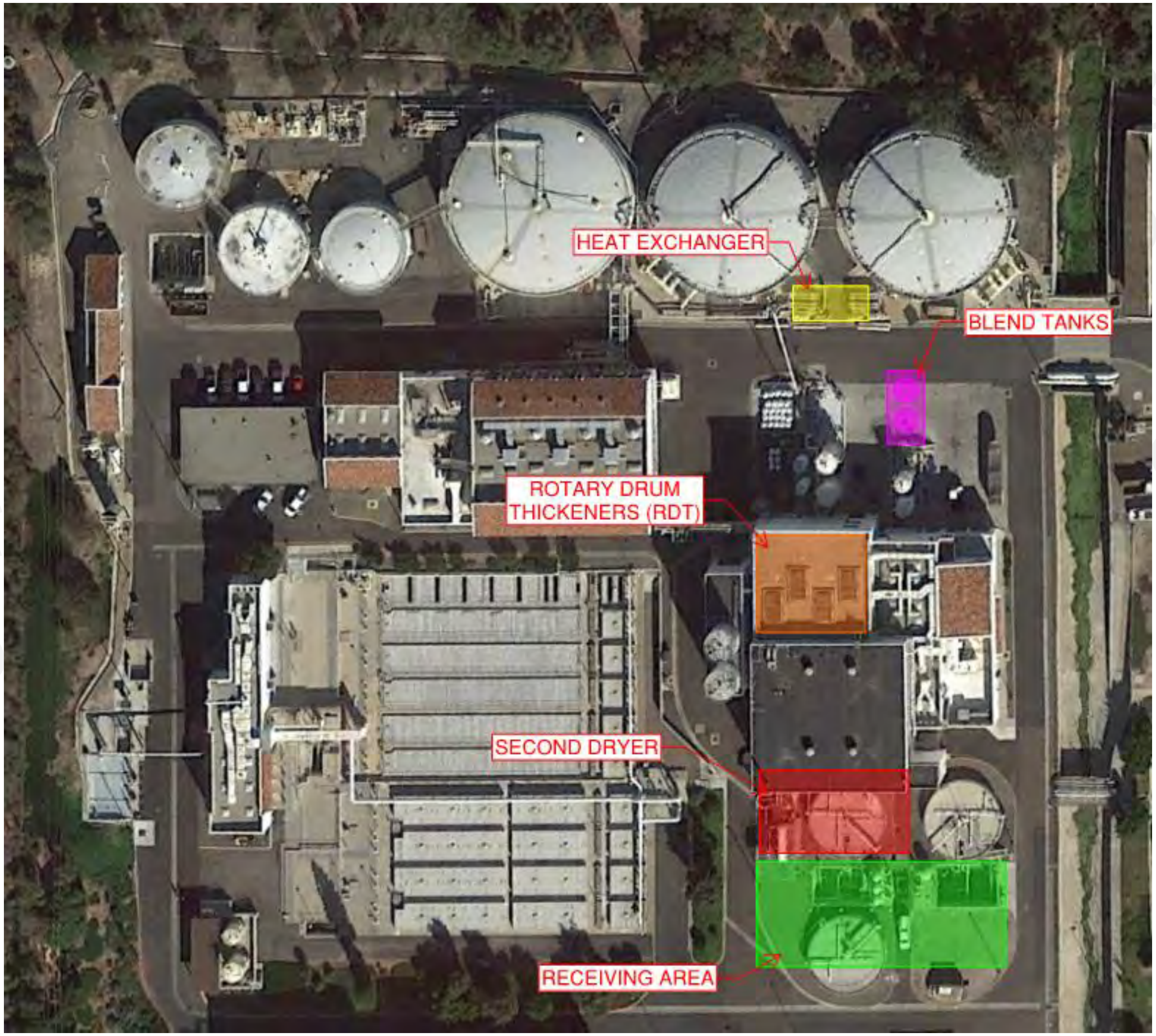
Pros and Cons

- Pros
  - Improved digestion and dewaterability allows for greater digester and dryer capacity; prolonging available dryer capacity
  - Allows for addition of high strength wastes into process train
  - Generates a high quality Class A cake, suitable for more local reuse
- Cons
  - More operational complexity
  - Occupies a greater footprint than digestion-only options
  - Somewhat greater energy demand

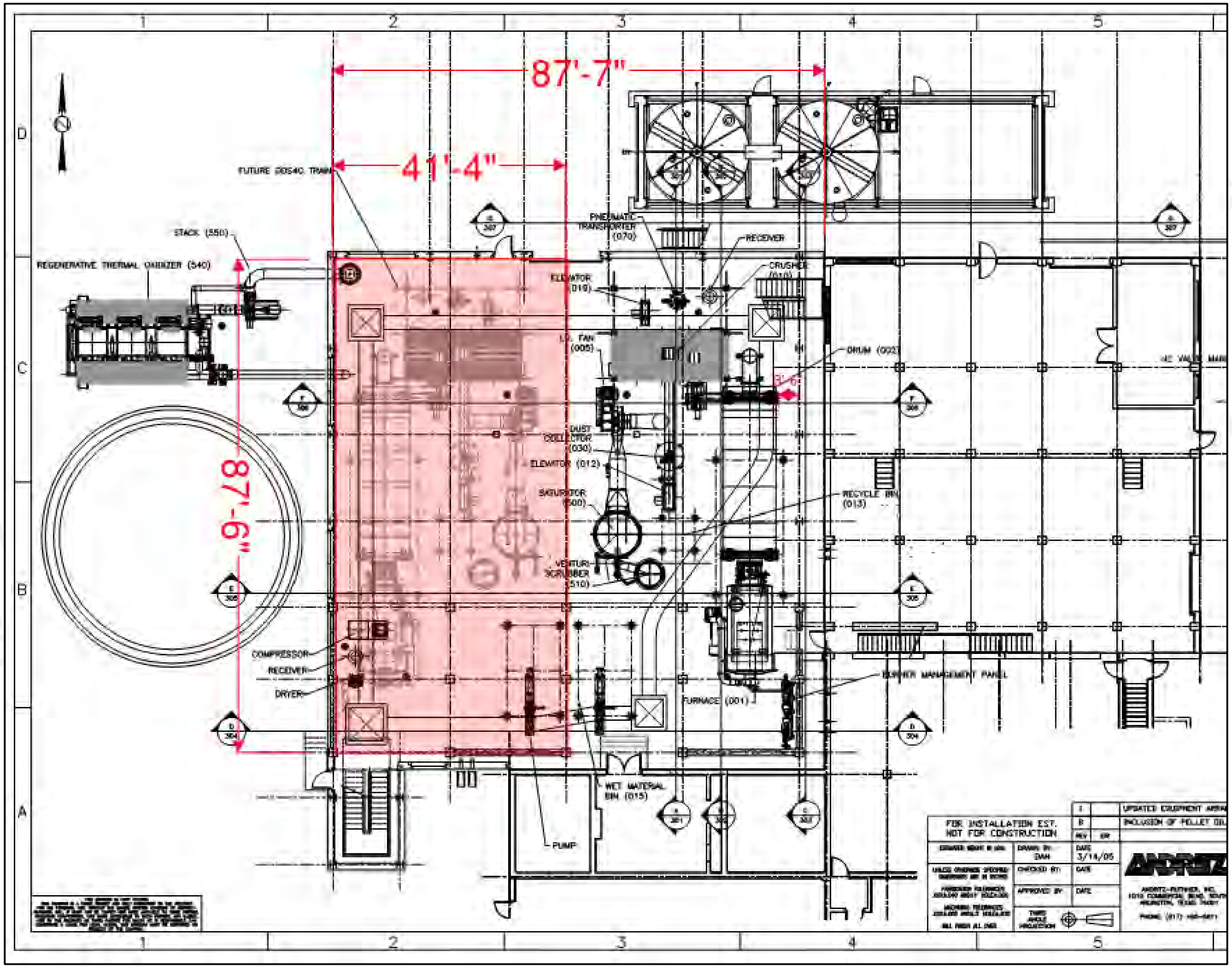
Building Dimensions – Biosolids Alternatives

- For THP Layout:
  - Pre-THP Dewatering Building: 60’ x 90’
  - Odor Control Building: 60’ x 30’
  - Thermal Hydrolysis Process (THP): 50’ x 90’
  - Cooling HEX: 8’ x 22’ each

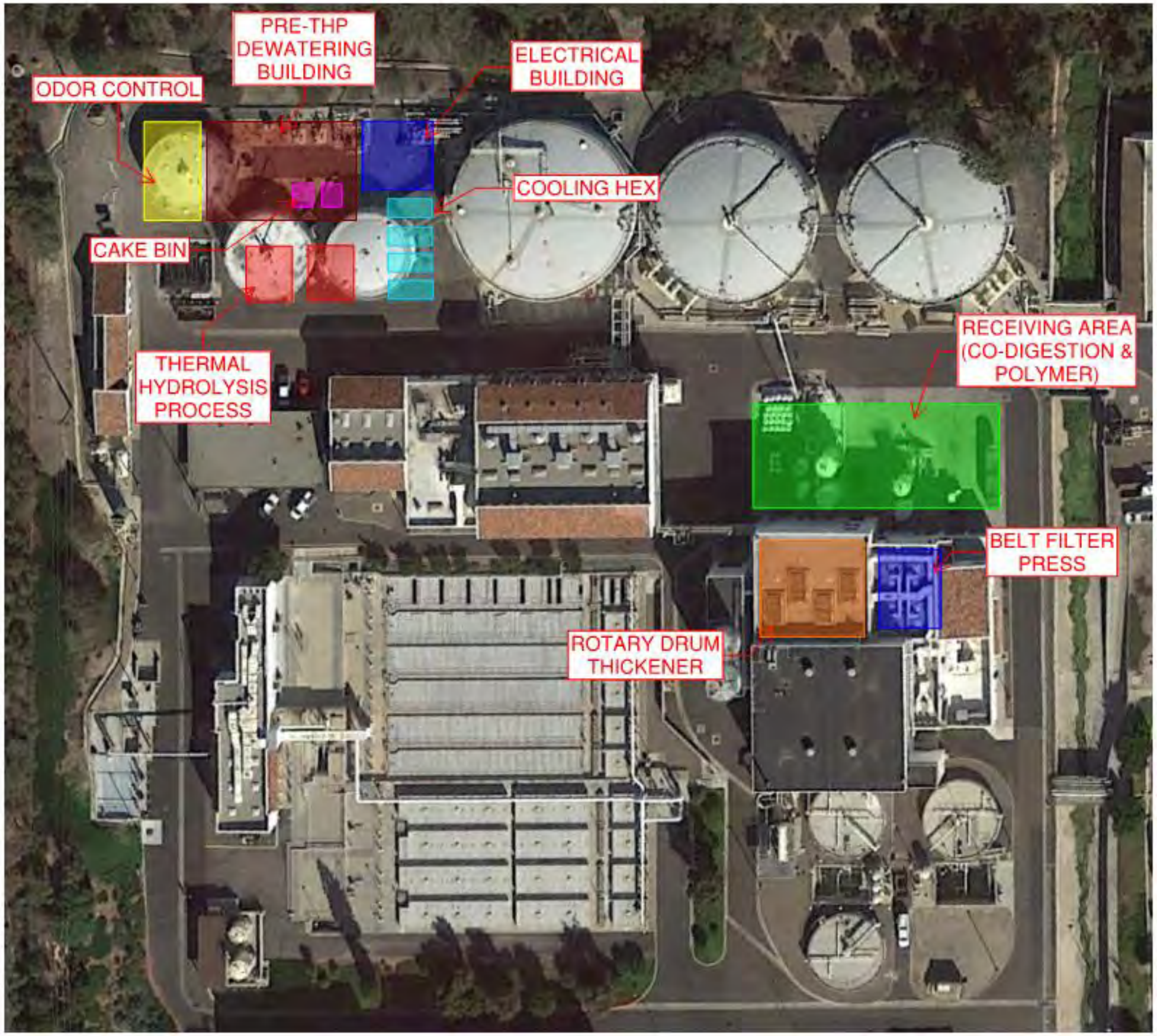
Thermophilic – Conceptual Layout



Thermophilic – Andritz Dryer



THP – Conceptual Layout 1



THP – Conceptual Layout 2

Codigestion Alternatives

- Codigestion with all stabilization alternatives
- Possibility to include separate food waste digestion in little tanks (for discussion)

Dewatering Alternatives

- Belt filter presses and centrifuges to be compared for performance with stabilization alternatives

Power Production Alternatives

- Will be paired with a thermophilic digestion baseline for comparison
- Best performing power production alternatives will be combined with best performing stabilization alternatives in second round of analysis

Alternatives: Power Production

- Baseline: Existing cogen + drying
- Baseline + gas conditioning
  - Gas conditioning serves to reduce O&M costs associated with engines and dryer
- Existing cogen + vehicle fuel (via pipeline injection or tube trailer)
  - No permit modification to cogen / no DG to dryer
  - Continue to operate two engines
  - Additional gas routed to vehicle fuel
- Existing cogen + microturbines
  - Includes gas conditioning
  - No permit modification to cogen / no DG to dryer
- Existing cogen + steam boiler/turbine
  - No permit modification to cogen / no DG to dryer
  - Additional gas routed to steam boiler; steam used in small turbine
- New cogen permit, CO catalyst and SCR, gas conditioning
  - Need to consider plant demand as a limit on power production
- Vehicle Fuel (primary use of DG) + existing cogen (natural gas + tail gas)
  - "All in" on vehicle fuel

Building Dimensions – Power Alternatives

- Gas Conditioning: 25’ x 80’ (+ chiller)
- Exhaust Treatment: 20’ x 75’
- Digester Gas Upgrading:
  - Pipeline injection: 50’x 95’
  - On-site vehicle fueling: additional 120’ x 150’ (fast fill)
  - Replaced the old Maintenance Building
- Microturbines: depends on desired capacity

Engine – Gas Conditioning + Exhaust Treatment

Microturbines with Gas Conditioning

Digester Gas Upgrading – Pipeline Injection

Digester Gas Upgrading – Vehicle Fuel

Notes:

- 400 scfm fast fill station with 48 hours of CNG storage, medium pressure storage, single stage separation membranes and 4 fuel dispensers.
- Footprint can be smaller with slow fill station, less storage, and fewer dispensers

Small Scale Solar PV

Large Scale Solar PV

Dual Membrane Gas Storage

Grant Updates

Grant Updates

- No current advertisements for grant funding
- Tracking EPA movements on RIN quotas and determination on codigestion (D3 or D5 RINs)
- Potential for local air district grant?

Self Generation Incentive Program

Program	Self-Generation Incentive Program (SGIP)
Agency	California Energy Commission / administered by SDG&E
Eligible Projects	Self-generation projects such as new engines, microturbines, or steam turbines – increased incentives for renewable/biogas projects; Energy storage / batteries
Funding	Incentives based on anticipated power output – based on fuel availability, not nameplate capacity; 50% paid upfront / 50% paid over 5 years based on performance
Schedule	Funding available each year / first-come, first-served Battery funding decreases as tiers fill up Projects must be operational within 18 months of award
How much are we talking?	~$500k - $1M depending on project size
Recommendation for SWEET Analysis	Don't count on funding to justify project economics
Next steps	Continue to track / pursue if selected alternatives meet criteria

Low-Carbon Fuel Standard

Program	Low-Carbon Fuel Standard (LCFS)
Agency	California Air Resources Board
Eligible Projects	Part of AB 32 scoping plan – projects that reduce the carbon intensity of California's vehicle fuel – i.e. renewable compressed natural gas (CNG vehicle fuel)
Funding	Incentives based on fuel production, market-based values; Paid on a per-gallon basis as the project performs
Schedule	Ongoing program, recently extended through 2030
How much are we talking?	Varies … could equate to ~$0.50/DGE - $1.00/DGE depending on market factors
Recommendation for SWEET Analysis	Include in SWEET analysis for vehicle fuel projects; Assume funding only through 2030, use conservative values
Next steps	Continue to track / pursue if vehicle fuel is recommended

Renewable Fuel Standard

Program	Renewable Fuel Standard
Agency	US Environmental Protection Agency
Eligible Projects	Renewable fuel projects– i.e. renewable compressed natural gas (CNG vehicle fuel)
Funding	Incentives based on fuel production, market-based values; Paid on a per-gallon basis as the project performs
Schedule	Ongoing program, not guaranteed beyond 2022
How much are we talking?	A lot of uncertainty: Wastewater digester gas is eligible for highest value of RINs – D3 EPA has recently stated that DG from food waste is a lower value – D5 EPA has the ability to set RIN quotas, which drive supply-and-demand, market-based pricing
Recommendation for SWEET Analysis	Include in SWEET analysis for vehicle fuel projects; Assume funding only through 2022, use conservative values
Next steps	Continue to track / pursue if vehicle fuel is recommended

Organics Grant Program

Program	Organics Grant Program
Agency	Department of Resource Recovery and Recycling (CalRecycle)
Eligible Projects	Projects that serve to divert organics (food waste) from landfill – toward anaerobic digestion or composting; recently issued with a food rescue requirement
Funding	Incentives based on project size and potential tons diverted
Schedule	Recently awarded, not expected to reissue for ~18 months
How much are we talking?	Up to $4M per project
Recommendation for SWEET Analysis	Do not include – too competitive to count on
Next steps	Continue to track / pursue if food waste receiving is recommended

Heathy Soils Program

Program	Healthy Soils Program
Agency	California Department of Food and Agriculture
Eligible Projects	Demonstration projects that sequester carbon and reduce GHG emissions – groups within CASA
Funding	Incentives based on project size and potential GHG benefit
Schedule	Currently accepting applications through September 19 Annual funding program (AB 32 funds), amounts and criteria may vary
How much are we talking?	Up to $3.75M total
Recommendation for SWEET Analysis	Do not include / ancillary benefit to support end use program
Next steps	Continue to track / connect with CASA Science and Research Group for potential partnerships

Green Project Reserve

Program	Green Project Reserve
Agency	California Water Resources Control Board
Eligible Projects	Projects that improve energy efficiency, renewable energy generation, or recycled water production
Funding	A component of Clean Water State Revolving Funding; Green Project Reserve is a "loan forgiveness" program CWSRF is generally oversubscribed, but GPR is underutilized
Schedule	Ongoing
How much are we talking?	Up to $4M per project, or 50% of project value, whichever is higher
Recommendation for SWEET Analysis	Do not include
Next steps	Something for EWA to keep in mind – if a larger capital project requires funding, consider CWSRF and adding an eligible GPR component

Look Ahead & Wrap-Up

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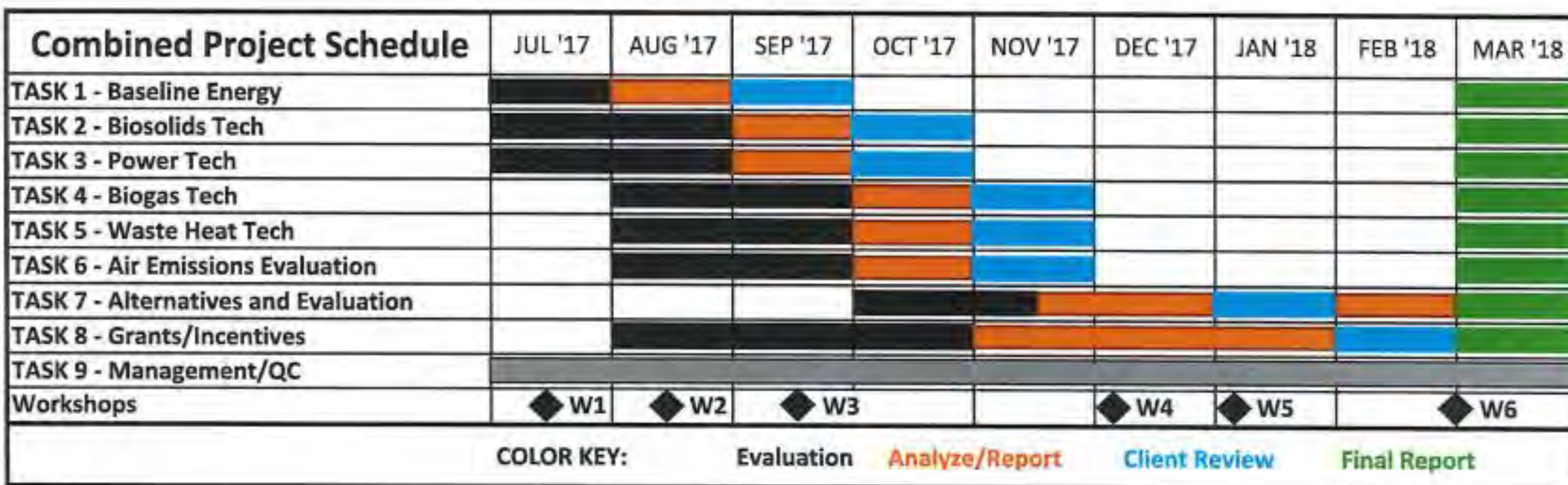
Project Schedule

- Schedule webinar for initial SWEET results in late October
- TM 1 delivered today
- TMs 2 and 3 delivered by month end
- Next in-person workshop in December



Look Ahead – December Workshop

- Results of initial SWEET analysis
- SWEET sensitivity analysis
- Screening and creation of new alternatives for Round 2 SWEET analysis
- Initial Development of Non-Cost Criteria
- Grants update

Wrap-Up

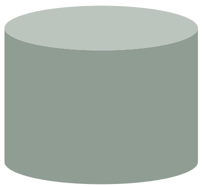
QUESTIONS?

it's about connecting

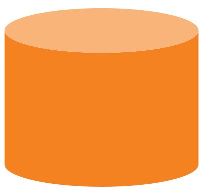
Brown AND Caldwell : essential ingredients®

Bull Pen

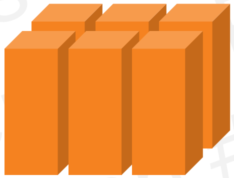
Digestion Processes



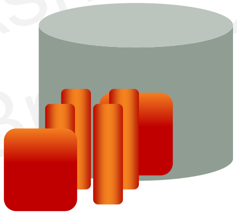
Mesophilic



Thermophilic



Class-A Thermophilic



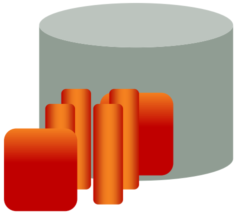
Thermal Hydrolysis

Mesophilic

- Operates at 95-100 ^{O}F
- Requires 15-day HRT/SRT at Max14 Loading to comply with Process to Significantly Reduce Pathogen (PSRP, EPA part 503)
- Organic loading limited to 0.18 lbs. VS/CF-Day at Max14 with one out of service

Thermophilic

- Operation at ~135^{O}F
- 7-Day SRT/HRT at Max07 with one unit out-of-service
- Likely limited to 9- or 10-Day based on organic loading limitation of 0.35 lbs. VS/CF-Day at Max07
- No improvement in process VSR and gas production
- Not Class-A by itself; But can be modified for Class-A

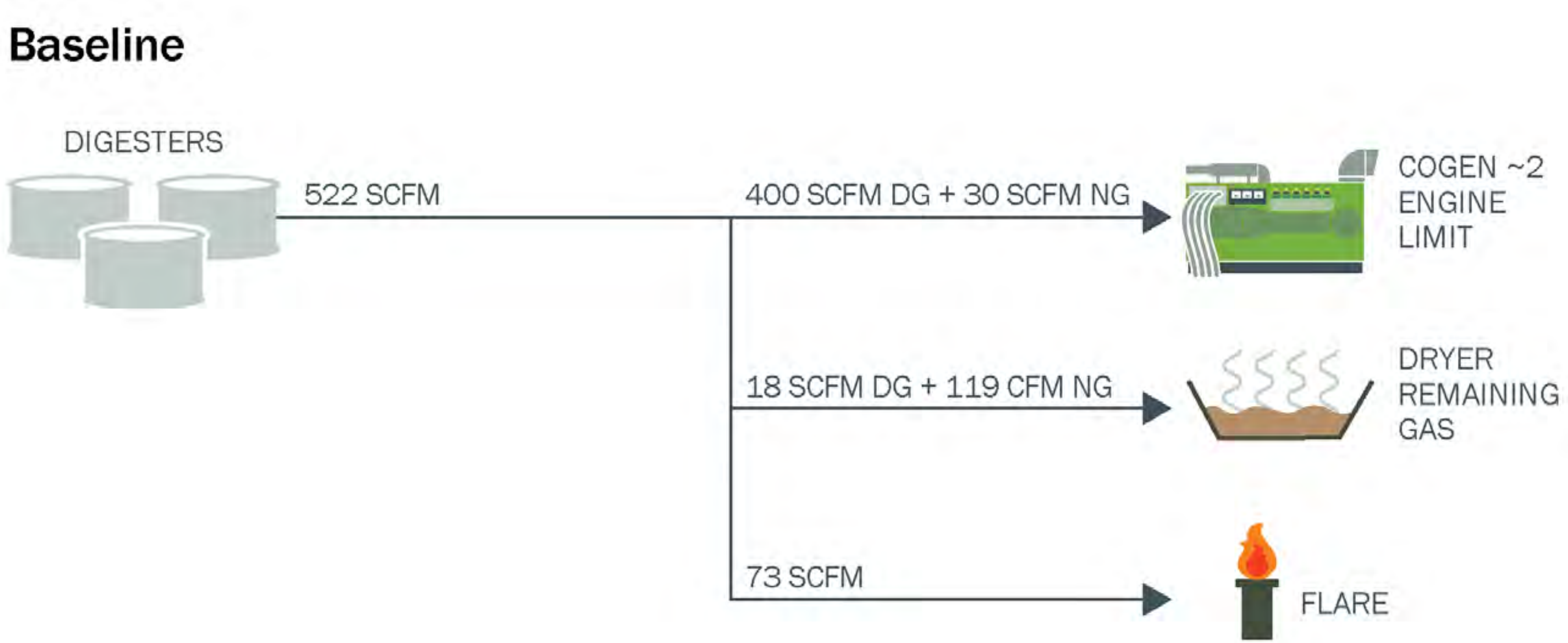


Thermal Hydrolysis

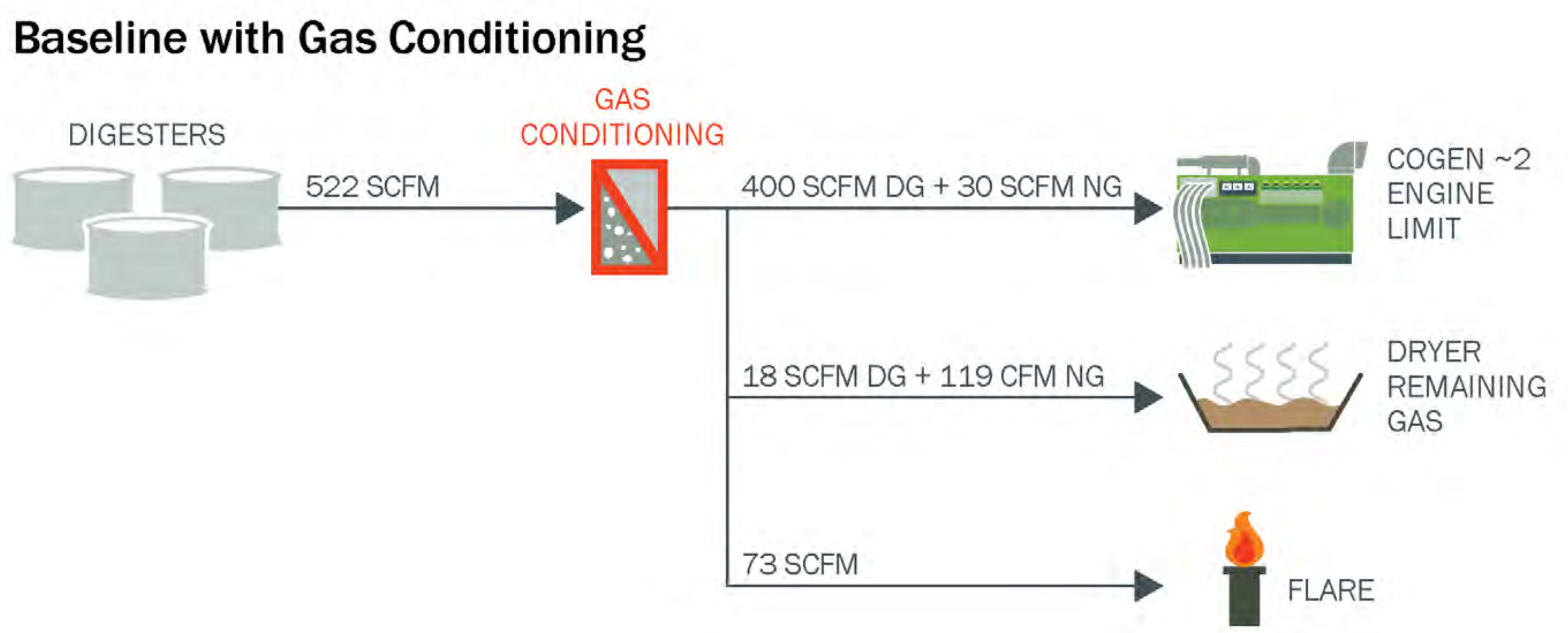
Assumes:

- Addition of Sludge Screening
- Addition of Centrifuge Pre-Dewatering
- THP – Will assume Cambi B6-4(s)

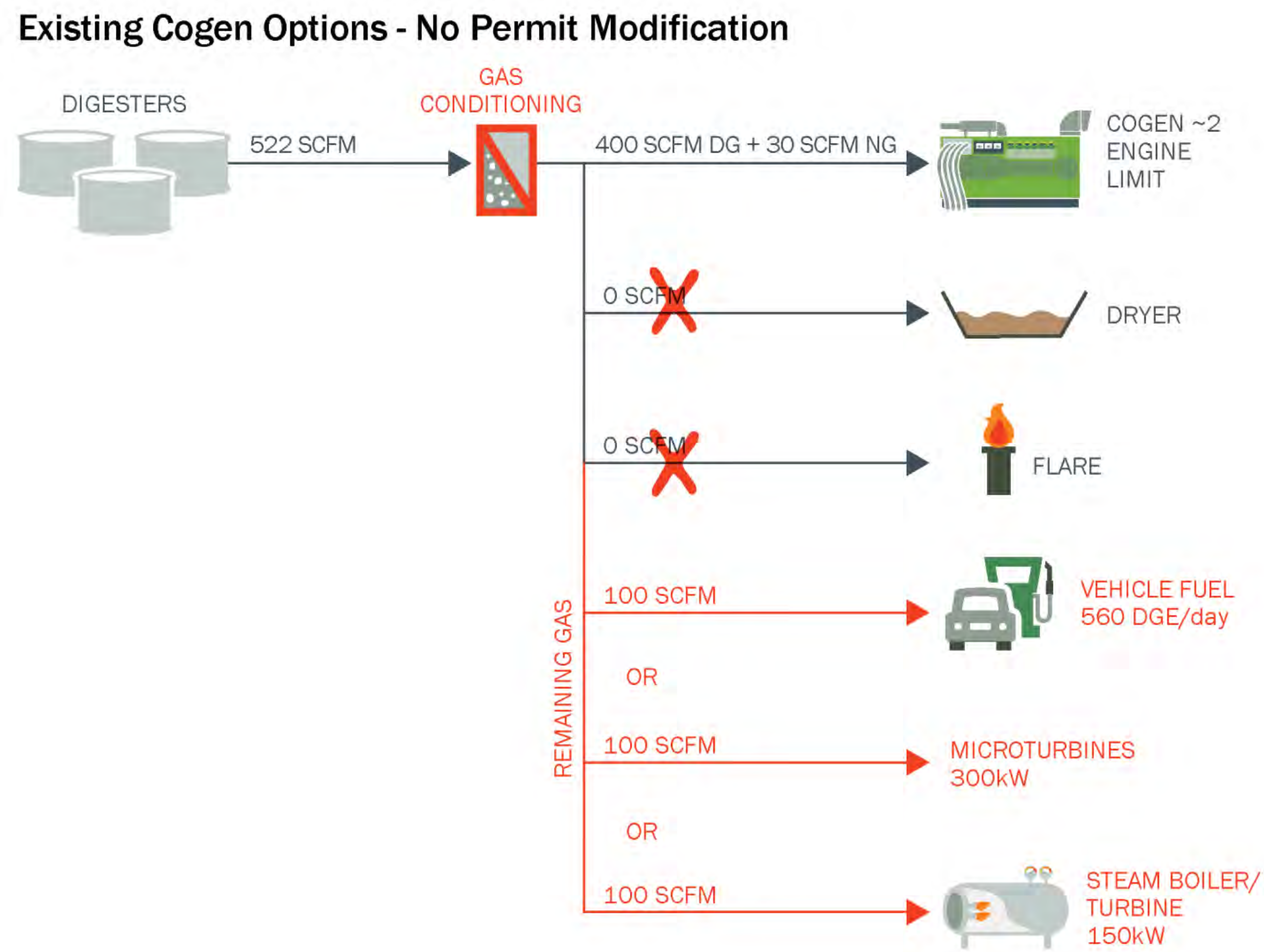
Baseline includes cogeneration (permit limited), dryer and some flaring



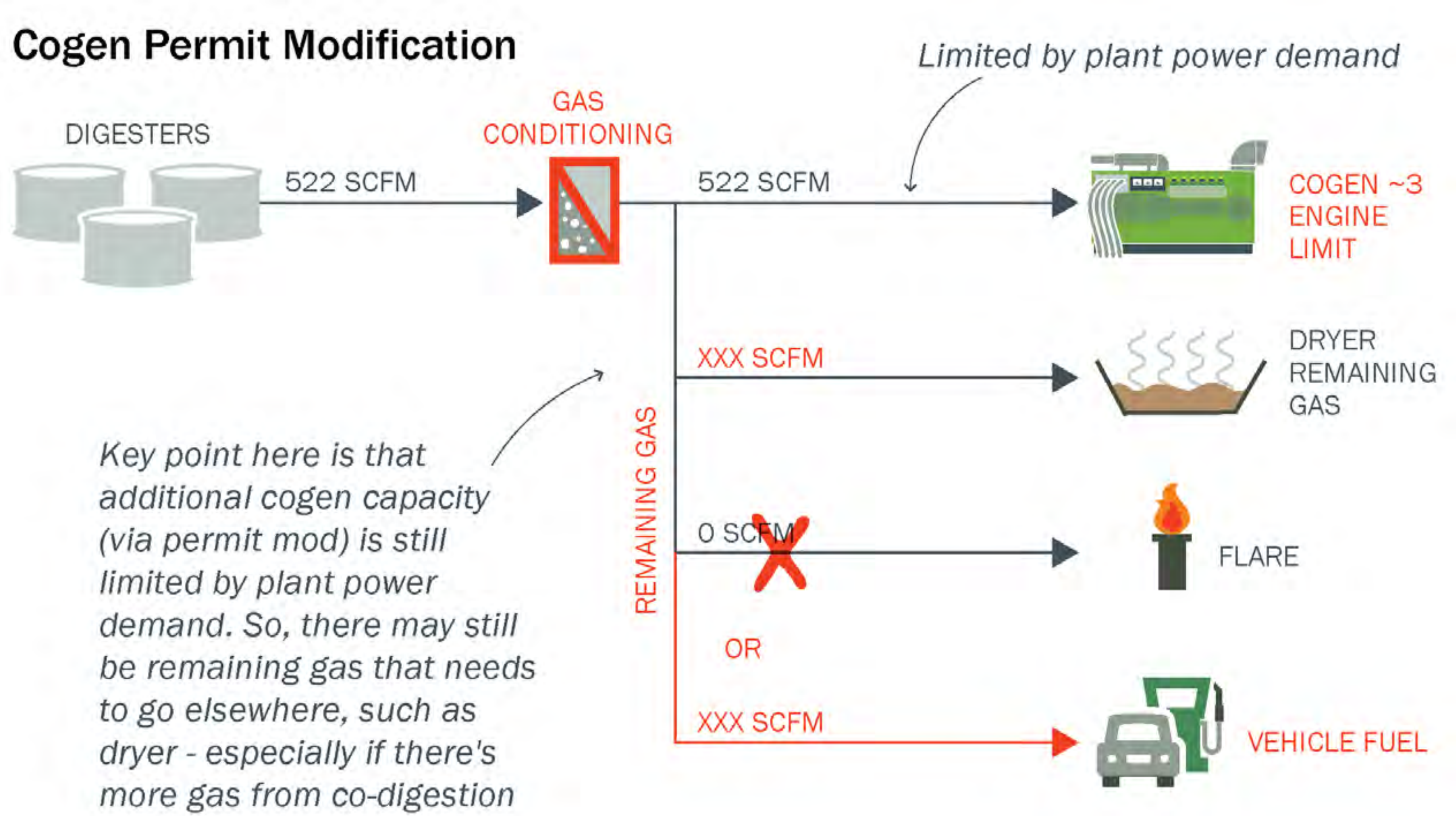
Gas conditioning could reduce engine and dryer O&M costs associated with siloxanes



With the existing permit in place, where else can we send digester gas to get highest value?

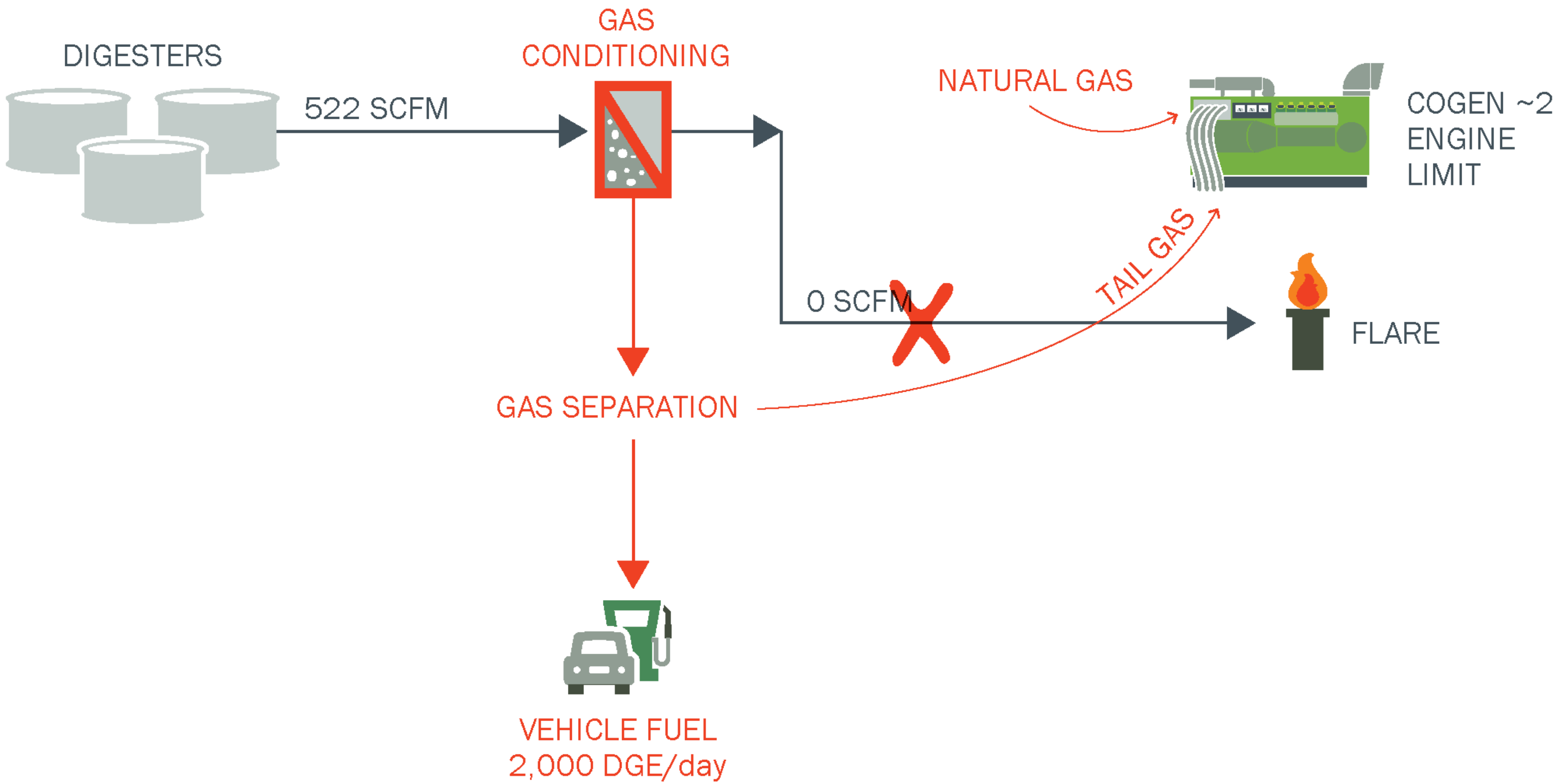


A permit modification allows EWA to meet plant electricity demand, but any additional gas would need to go to a non-generating use



An all-vehicle-fuel option may deliver the best economics

Vehicle Fuel



Attachment B: Evaluation of Alternative Fuel Digester Loading Strategy

Technical Memorandum, Trussell Technologies Inc.

ENCINA WASTEWATER AUTHORITY
Serving North San Diego County

Technical Memorandum
Evaluation of Alternative Fuel Digester Loading Strategy

October 2017

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Trussell Technologies Inc

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LIST OF ABBREVIATIONS

Description	Abbreviation
Anaerobic Digestion	AD
Alternative Fuels	AF
Alternative Fuel Receiving Facility	AFRF
Chemical Oxygen Demand	COD
Digester Gas	DG
Engineered BioSlurry	EBS
East Bay Municipal Utility District	EBMUD
Encina Wastewater Authority	EWA
Encina Water Pollution Control Facility	EWPCF
Fats, Oil, and Grease	FOG
Food Waste	FW
Los Angeles County Sanitation Districts	LACSD
Long Chain Fatty Acid	LCFA
Liquid Environmental Solutions of California	LES
Lauter Tun Drip	LT Drip
Natural Gas	NG
San Francisco Public Utilities Commission	SFPUC
Total Kjeldahl Nitrogen	TKN
Technical Memorandum	TM
Total Solids	TS
Trussell Technologies, Inc.	TT
Volatile Acid	VA
Volatile Acid/Alkalinity	VA/Alk
Volatile Fatty Acid	VFA
Volatile Solids	VS
Volatile Solids Reduction	VSR
Water Reclamation Plant	WRP

1. INTRODUCTION

The co-digestion of biodegradable wastes with municipal sludge at wastewater facilities employing anaerobic digestion has been receiving more and more attention over the past several years. Some key drivers for this are:

- Produce additional biogas that can be used to generate electricity or offset natural gas needs
- Divert biodegradable wastes from other disposal paths (e.g., landfills)
- Utilization of existing anaerobic digestion capacity at wastewater facilities

In 2011, the Encina Wastewater Authority (EWA) decided to implement co-digestion of Alternative Fuels (AFs) through its energy and emissions strategic planning effort. EWA started operation of its Alternative Fuel Receiving Facility (AFRF) at the Encina Water Pollution Control Facility (EWPCF) in 2015.

1.1 Objectives of this Technical Memorandum

The EWA engaged Trussell Technologies, Inc. (TT) to provide technical support for the anaerobic digestion process at the EWPCF, focusing on an evaluation of the AF system. This technical memorandum (TM) presents the findings of the evaluation according to the objectives listed below:

a) Summarize EWA's experience with AF co-digestion to date
b) Provide an overview of relevant co-digestion programs in California
c) Summarize the key findings from a literature review on co-digestion of AFs
d) Describe process considerations for AF co-digestion at EWPCF, including capacities of the AF and related systems
e) Present operational strategy and process monitoring recommendations

1.2 Alternative Fuel Co-Digestion Experience at EWPCF

Except for some short-term testing on brewery waste in April 2017, all the AF co-digested so far at EWPCF has been Fats, Oil, and Grease (FOG) from Liquid Environmental Solutions of California, LLC (LES) through a competitively let contract awarded in December 2013. FOG co-digestion has been conducted continuously since May 2015, with deliveries from LES of 80,000 gallons per week (the maximum contracted volume) since January 2017. A comparison performed by RMC of digester gas production in 2016 with FOG co-digestion to digester gas production in 2014 before FOG co-digestion showed a volumetric increase of 29% with similar methane content, which corresponds to a unit energy production factor of approximately 0.104 therms per gallon of LES FOG. It should be noted that, in addition to biomethane being produced directly from the AF, enhanced digestion of the municipal sludge due to co-digestion can contribute to the increase in biomethane production.

EWA performed side-by-side co-digestion testing of LES FOG and a brewery waste from Stone Brewery known as Dewatered Lauter Tun Drip (LT Drip) in April 2017. For the testing, FOG was fed to Digester 5 and Dewatered LT Drip was fed to Digester 6 to assess the relative performance of the two AFs as the two digesters were fed typical volumes of municipal sludge equally. The limited data on the composition of the AFs are presented in Table 1.

Table 1 Alternative Fuel Composition

Parameter	Units	Alternative Fuel (AF)	
		LES FOG	Dewatered LT Drip
Total Solids (TS)	%	1-10	4-6
COD(total)	mg/L	100,000-200,000	60,000-130,000
Volatile Solids (VS)	% of TS	-	~98

No problems related to digester stability were observed during the month-long test in which a total of 409,812 gallons of FOG and 290,365 gallons of Dewatered LT Drip were fed to Digester 5 and Digester 6, respectively. Dividing the digester gas produced from each digester by the volume of AF fed over the test period indicated the co-digestion of Dewatered LT Drip resulted in about 38% more digester gas production than co-digestion of LES FOG per gallon of AF. Lab analysis of Dewatered LT Drip performed after this testing indicated that nearly all the COD was in the soluble form, which allows this AF to biodegrade easily.

2. OVERVIEW OF CO-DIGESTION PROGRAMS AT WASTEWATER FACILITIES

An overview of three significant co-digestion programs implemented at California wastewater facilities is provided below. The AFs used in these programs include FOG, food waste (FW) slurry, food scraps, poultry processing waste (blood and body parts), cheese and yogurt production waste. Our review did not identify a program where brewery waste is being co-digested with municipal sludge at full scale.

2.1 FOG at San Francisco Public Utilities Commission (SFPUC)

The SFPUC began FOG co-digestion in 2010 at its Oceanside Plant, a 21 MGD (currently treating 15 MGD) pure oxygen activated sludge plant designed for BOD removal. It has four egg-shaped digesters (0.75 MG each) operated in a single-stage mesophilic mode. The FOG receiving and injection equipment includes six tanks (4,000 gallons each), and a mixing and heating system capable of heating the FOG to 150 degrees F. Over a study period of January to August 2012, the FOG averaged total solids (TS) of 6%, volatile solids (VS) of 93%, pH of 4.2, and chemical oxygen demand (COD) of approximately 144,000 mg/L. The VS from FOG fed to the digesters averaged 6% of the total VS fed, and for short periods this value reached as high as 47% with no negative impacts on the digestion process. FOG co-digestion increased the volume of biogas produced by 19%, and the methane content of the biogas from 59% to 63%. This corresponded to an increase in methane gas production of 27%.

Other impacts of FOG co-digestion on the performance of the Oceanside Plant's digestion system are summarized below.

- The seasonal foaming typically experienced during warmer months (June to October) was not observed to be different (i.e., was not made worse or improved).
- No significant difference was observed in the mass of digested sludge to be disposed of.
- No scum layer formation or grease flotation was observed in the egg-shaped digesters despite the gradual decrease in digester mixing from six turnovers per day to less than three.

2.2 Food Waste Slurry at Los Angeles County Sanitation Districts

The Los Angeles County Sanitation Districts (LACSD) started a demonstration program to co-digest FW slurry in one of its 24 active digesters (3.7 MG each) at the Carson facility in 2014. A single-stage mesophilic digestion process is utilized. They contracted with Waste Management to provide a FW slurry known as Engineered BioSlurry (EBS), which is source separated food wastes from grocery stores, food processors, and restaurants that are processed into a slurry of about 14% TS. The FW slurry, similar in thickness to cooked oatmeal, has a VS of approximately 92%, and COD of 222,400 mg/L. The food waste slurry specifications include the criteria listed below.

1.	pH:	3.0 – 7.0
2.	Total Solids:	10.0 – 15.0%
3.	Volatile Solids (% of Total Solids):	Greater than 80%
4.	Electrical Conductivity:	Less than 15 millimho/cm
5.	Volatile Acids (Acetic Acid Equivalents):	Less than 15,000 mg/L
6.	Total COD:	Greater than 160,000 mg/L
7.	Total BOD:	Greater than 80,000 mg/L
8.	Specific Gravity@25^{o}C:	0.95 – 1.10
9.	Kinematic Viscosity@25^{o}C:	Less than 200 cps
10.	Ammonia as Nitrogen (NH_3-N):	Less than 600 mg/L
11.	Total Kjeldahl Nitrogen (TKN):	Less than 7,500 mg/L
12.	Total Carbon:	Greater than 9,000 mg/L
13.	Arsenic:	Less than 1 mg/L
14.	Calcium:	Less than 3,000 mg/L
15.	Chloride:	Less than 3,000 mg/L
16.	Chromium:	Less than 2 mg/L
17.	Magnesium:	Less than 500 mg/L
18.	Mercury:	Less than 1 mg/L
19.	Nickel	Less than 5 mg/L
20.	Potassium:	Less than 3,000 mg/L
21.	Sodium:	Less than 3,000 mg/L
22.	Total Heavy Metals(Ag, As, Ba, Cd, Co, Cr, Cu, Hg, Mo, Ni, Pb, Sb, Se, Ti Sr, Sn, V, and Zn):	Less than 50 mg/L
23.	Film Plastic > 4 mm	Less than TBD % by dry weight
24.	Glass > 4 mm	Less than TBD % by dry weight
25.	Total Inerts > 4 mm (Film and hard plastics, Glass, metal & rocks) (Method TMECC 0306)	Less than TBD % by dry weight

LACSD's FW slurry co-digestion plan is summarized in Table 2.

Table 2 Food Waste Slurry Co-Digestion Plan at LACSD

Parameter	Units	Test Digester	Control Digesters
Wastewater Sludge Feed	gal/day	205,000	205,000
	% solids	3.2%	3.2%
	tons per day solids	27.3	27.3
Food Waste Slurry Feed	gal/day	20,000	---
	% solids	14%	---
	tons per day solids	11.7	---
% Food Waste Slurry	volume basis	9%	---
	solids basis	30%	---
Total Feed	gal/day	225,000	205,000
	% solids	4.2%	3.2%
	HRT, days	16.4	18.0

The feed rate target of 20,000 gal/day for FW slurry was reached in October 2016, and the biogas production in the test digester has been about 62% greater than the control digesters. The test digester has demonstrated a higher volatile solids reduction (VSR) (54.4% versus 50.3% for the control), which translates to similar TS and VS in the digested sludge for the test and control digesters (test digester: 2.37% TS and 60.9% VS; control digester: 2.28% TS and 59.5% VS). LACSD reports that treatment plant operations are not significantly impacted by the co-digestion, and the success of this program has led to plans to expand the FW slurry co-digestion to four additional digesters (i.e., 100,000 gal/day). A couple of challenges to be aware of are controlling the amount of inert material in the food waste slurry (e.g., grit and plastics), and its relatively high viscosity can lead to long truck unloading times.

2.3 High-Strength Waste at East Bay Municipal Utility District (EBMUD)

Motivated in part by excess capacity in both the liquid and solids treatment processes (i.e., design capacity of 120 MGD and currently treats 50 MGD), EBMUD began co-digesting organic wastes with their municipal sludge more than a decade ago. Along the way, they've performed many studies and tests to improve the understanding of the mechanisms and impacts of co-digestion. Currently, the eleven digesters are operated in a two-stage, thermophilic configuration where the first stage is maintained at 50 degrees C (122 deg F), and the second stage is not heated. A summary of EBMUD's co-digestion program is given below.

- FOG is received at a rate of 50,000 – 60,000 gal/day
- Food scraps are received at 10 – 15 tons/day
- Protein wastes (e.g., blood, chicken parts, cheese waste, and yogurt waste) are also received
- All co-digestion waste is received in blend tanks (two at 200,000 gal each) where it is processed into a pulp for injection into first stage digesters
- Online COD analyzers are utilized to control loading rates
- The average HRT is about 15 days (facility is approved for a 10-day running average HRT)
- Energy from biogas met about 50% of facility demand prior to co-digestion
- Energy from biogas currently meets 130% of facility demand (i.e., export to grid)

Challenges have been experienced with the grit content of the FOG, inert debris in the food scraps (e.g., plastics), and digester foaming when lactose was co-digested. EBMUD has reported the following findings related to the co-digestion of food scraps.

a) Food scraps produce as much or more energy than wastewater solids per ton of dry solids fed to the digesters.
b) VSR of food scraps proceeds at a quicker rate and to a greater extent than wastewater solids (VSR is 70% - 80% for food scraps, and 50% - 60% for wastewater solids).
c) Food scraps produce about half the dry tons of digested sludge compared to wastewater solids.

3. LITERATURE REVIEW

A literature review was conducted to identify items that could be relevant to the decisions EWA will be making on co-digestion of AFs. As such, this review focused on the co-digestion of FOG, FW slurry, and brewery wastes with wastewater solids since these AFs are the most likely to be utilized by EWA. The key areas of interest were the loading rates used, DG production, digester stability impacts, solids dewatering impacts, and impacts on the quality of return streams (e.g., centrate).

3.1 FOG Co-Digestion

Articles relating to FOG co-digestion have a common theme that a significant increase in DG production can be realized with little risk of negative impacts. Suto et al. (2006) conducted bench scale tests of FOG co-digestion with primary and secondary sludge from the main EBMUD plant at mesophilic (95 deg F) and thermophilic (122 deg F) temperatures. Their observations are summarized below.

- FOG characteristics (TS, VS, COD) were highly variable.
- FOG feed rates of 20% and 35% of total feed (by volume) resulted in increases in DG production of 17% to 94% while maintaining stable digester conditions.
- A FOG feed rate of 50% of total (by volume) resulted in digester instability after about 10 days.
- Thermophilic digestion showed an increased ability to degrade the long chain fatty acids (LCFAs) associated with FOG compared to mesophilic digestion.

A key component of FOG for methane production are the LCFAs, which are composed of a carbon chain (C_8 to C_{20}) with a carboxyl group on the end. Many researchers have observed inhibition of methane production due to LCFAs, with the mechanism thought to be LCFAs adsorbing to bacterial cell membranes, resulting in mass transfer limitations. Consequently, the upper limit for FOG loading to maintain stable digestion may be a function of LCFA concentrations. Suto et al. (2006) observed that oleic acid (C_{18}) and palmitic acid (C_{16}) were the most abundant LCFAs in the FOG used in their study. Addition of these specific LCFAs showed inhibitory effects when the concentrations in the mesophilic digester sludge reached 1,600 mg/L for oleic acid, and 4,000 mg/L for palmitic acid.

Kabouris et al. (2009) performed bench scale tests of FOG co-digestion with primary and secondary sludge from a plant in Pinellas County Florida at mesophilic (95 deg F) and thermophilic (126 deg F) temperatures. They observed stable digestion when FOG accounted for 48% of the VS loading, and the methane yield per unit mass of VS added at mesophilic temperature was 2.9 times greater than digestion without FOG addition (290% of the normal methane production). Pinellas County used a FOG that had been dewatered using gravity separation with polymer addition.

Other investigators (Li et al., 2013; Tandukar and Pavlostathis, 2015) have observed similar results (i.e., stable digestion at high FOG loading rates with significant increases in DG production). Due to the very high volatile solids reduction (VSR) for FOG (typically over 90%) and increased VSR for the wastewater solids that often accompanies FOG co-digestion, the dry weight of solids to be dewatered is usually the same or less than digestion without FOG addition.

3.2 Food Waste Slurry Co-Digestion

The LACSD FW slurry program described earlier provides the most relevant guidance to potential FW slurry co-digestion at EWA, with the key items being the loading (30% of solids loading from FW slurry) and the criteria relating to the composition of the FW slurry. A review of the literature revealed that potential inhibition of methane production at higher loadings is likely caused by volatile fatty acid (VFA) accumulation resulting from the acidogenesis stage of digestion, which causes a drop in pH that inhibits methanogenesis (Hobbs et al., 2017). (note: volatile acid (VA) and VFA are often used interchangeably)

Cabbai et al. (2016) conducted a pilot scale study of the mesophilic co-digestion of FW slurry (derived from fruit and vegetable waste) with municipal sludge from a wastewater plant in Udine, Italy. The pilot digester (1:1000 scale of full size digester at the Udine facility) was initially operated without FW at a municipal sludge loading rate similar to the full scale (0.05 lb VS/ft^3-day), followed by a series of phases in which the FW slurry was increased from 1.5% to 29% of the total feed (volume basis). The highest VS loading rate tested was 0.2 lb VS/ft^3-day, with stable digester operation observed for all feed rates. The authors suggested the digester biology can tolerate higher organic loadings than the maximum value tested since their stability parameter (ratio of intermediate alkalinity from volatile organic acids to alkalinity from bicarbonates) never exceeded 0.10, well below 0.4 which is considered the upper limit for stable digester operation. The VSR increased as the FW slurry loading increased, with a VSR of 33% with no FW to 67% at the highest loading. As a result of the increased VSR, the TS in the digested sludge remained relatively constant at all loading rates. The methane content of the DG without FW slurry was 63%, and this value ranged between 64% and 71% during food waste co-digestion. The maximum DG production rate, observed at the highest loading rate, was 2.9 times greater than with no FW.

Our literature review re-emphasized the point that the nitrogen content (e.g., ammonia and protein content) of the FW slurry is an important consideration since nitrogen rich substrates can lead to high ammonia concentrations in the digesters. Inhibition of methane production can occur when ammonia reaches 1500 mg/L. Unlike FOG, which has a low nitrogen content, the nitrogen content of FW can vary greatly. The potential for ammonia toxicity is why LACSD has included ammonia and TKN (Total Kjeldahl Nitrogen) limits in their specifications for FW slurry.

3.3 Brewery Waste Co-Digestion

The beer brewing process produces multiple wastes, which includes spent grain, spent yeast, and the liquids from the processing and handling of the grain and yeast. Compared to FOG and FW co-digestion with wastewater solids, there has been much less published on the topic of brewery waste co-digestion. This is due to:

- Brewery waste being much less widespread than FOG and FW;
- Brewery waste has value as animal feed, and even as a component of food for human consumption;
- Breweries implementing their own waste-to-energy projects.

Nansubuga et al. (2015) studied the co-digestion of brewery waste with primary sludge from a wastewater plant in Kampala, Uganda. No details were given on whether the brewery waste was from a particular process at the brewery (e.g., spent yeast). The bench scale co-digestion was performed at mesophilic temperature at a retention time of 20 days. The brewery waste had a TS of 6.2%, VS of 77%, pH of 4.4, COD of 150,000 mg/L, and ammonia nitrogen of 67 mg/L. The primary sludge showed relatively poor biodegradability (VS around 50%) by itself due to long travel times in the sewers. The investigators observed stable digester operation at a brewery waste feed rate of 50% of total (by volume), with a DG production rate three (3) times greater than with no brewery waste. A test receiving only brewery waste as feed became unstable (pH drop) at a retention time of 28 days.

Earlier studies (Pecharaply et al., 2007; Barbel et al., 2009) tested the co-digestion of brewery sludge with wastewater solids from a Bangkok, Thailand wastewater plant. Since the main objective of the studies was to assess the impact of co-digestion on the suitability of the dewatered sludge as a fertilizer for agriculture (e.g., pathogen, heavy metal, and nutrient content), the amount of data presented on the co-digestion process was limited. Their bench scale tests at mesophilic temperature did indicate that a brewery waste feed rate of 75% of total (by weight), which corresponded to a VS loading rate of 0.094 lb VS/ft^3-day, provided the highest DG production and VSR (note: this is a relatively low loading rate in terms of typical anaerobic digesters). The reported DG methane content for all brewery waste feed rates tested was surprisingly high at over 70%.

4.0 PROCESS CONSIDERATIONS FOR EWPCF

For the co-digestion of AFs at EWPCF, process considerations relating to digester stability, digester gas use and production, solids dewatering and drying, and centrate quality are discussed in this section.

4.1 Digester Stability

The stability of the AD process can be affected in various ways when AFs are being co-digested and are summarized below:

a) ***LCFA inhibition of methanogenesis due to high LCFA concentrations from FOG addition***
The inhibition of methanogenesis means the conversion of VFAs slows down, which in turn leads to an increase in VFA concentration and an associated drop in pH. Since the literature has mixed results as to whether higher FOG loadings translate to LCFA inhibition, the risk of this type of inhibition is expected to be relatively low.

b) Digester acidification (pH drop) due to excessive loading (Volatile Solids or Organic)
Under conditions of digester overloading, the formation of VFA (acidogenesis) exceeds the rate of VFA utilization by methanogens, which leads to VFA accumulation. All of the AFs considered in this memo (i.e., FOG, FW slurry, and brewery waste) have the potential for this type of impact.

c) Ammonia inhibition due to the toxic effect of ammonia at high concentrations
The AD of organic nitrogen (e.g., protein) produces ammonia, which is toxic in its nonionized form (NH_3) (Rittmann and McCarty, 2001). An ammonia nitrogen concentration of about 1500 mg/L is typically cited as the concentration where inhibition of methanogens begins. FW slurry and brewery waste containing significant organic nitrogen can lead to ammonia inhibition.

d) Hydrogen sulfide inhibition due to toxicity at high concentrations
The AD of sulfate and organic sulfur compounds produces hydrogen sulfide, which can be toxic to the digester biology at concentrations above 200 mg/L. FOG is typically low in sulfur, but food waste slurry and brewery waste may contain enough sulfur to be of concern.

e) Heavy metal inhibition due to toxicity at high concentrations
Since the AFs under consideration are typically low in heavy metals, the risk of this type of inhibition is expected to be relatively low.

f) Potential to exacerbate digester foaming
Lactose addition has been reported to have a high risk of digester foaming and/or acidification. Consequently, this AF should be avoided.

The monitoring of typical parameters associated with digester operation like the VFA to alkalinity ratio (VFA/Alk), ammonia concentration, hydrogen sulfide concentration, and heavy metal concentrations will greatly reduce the risk of digester instability. Specifying and monitoring criteria for the content of AFs received will reduce the risk further. In addition, digester stability has been shown to be more robust at thermophilic temperature (Kabouris et al., 2009; Sprague et al., 2012), especially when it comes to VS/organic loading. This isn't surprising because of the fundamental impact of temperature on the rate of biochemical transformations (i.e., an increase in temperature of 10 degrees C typically results in a doubling of reaction rates). Implementation of thermophilic digestion is an option for increasing the VS loading capacity without increasing digester volume.

4.2 Digester Gas Use and Production

Since increasing DG production for beneficial use is an important motivation for implementing AF co-digestion, we need to understand just how much DG can be utilized. A schematic representation of the AF System at the EWPCF is shown in Figure 1.

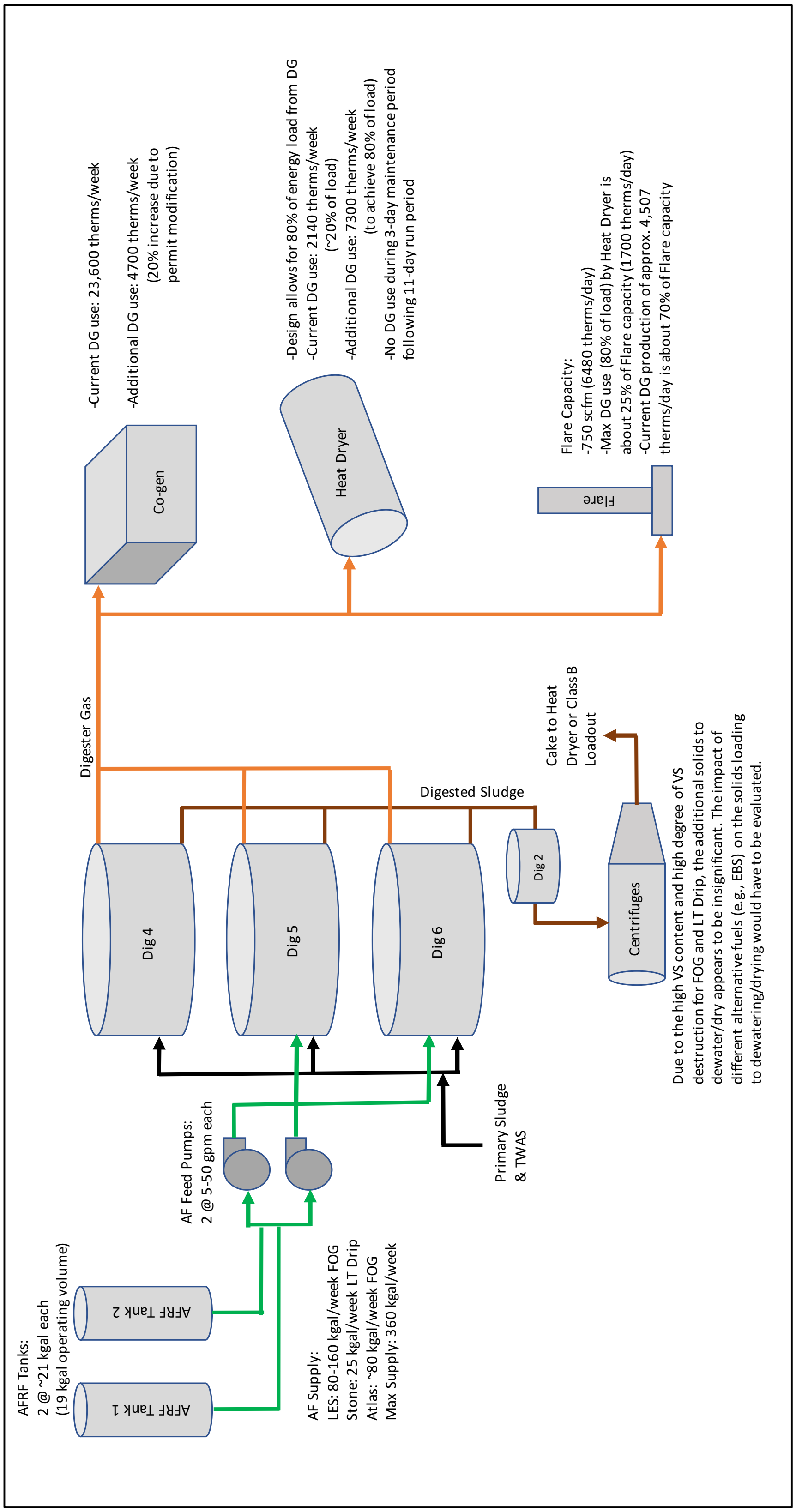

Figure 1 Schematic of AF System Showing Various Capacities and Operating Conditions

As shown in Figure 1, digester gas can be beneficially used by Co-gen and the Heat Dryer. By design, this equipment utilizes both natural gas (NG) and DG. A summary of DG and NG use, along with DG production, is presented in Table 3.

Table 3 Summary of DG and NG Use Along with DG Production

		Therms/week	Therms/day	Notes/Comments
Heat Dryer				Based on May 2016 - April 2017 data
	Total gas use	11,800	1,686	Heat Dryer typically runs at or near capacity
	Current NG use	9,660	1,380	About 80% of capacity based on therms
	Current DG use	2,140	306	About 20% of capacity based on therms
	Max DG use	9,440	1,349	Design capacity is 80% of therm load
	Min NG use	2,360	337	20% of therm load from design
	Additional DG use	7,300	1,043	Additional DG that can be used by Heat Dryer
Co-gen Engines				Based on May 2016 - April 2017 data
	Current DG use	23,600	3,371	
	Current NG use	2,245	321	
	Additional DG use	4,700	671	20% increase in DG to co-gen upon permit modification
Flare				Based on May 2016 - April 2017 data
	Current DG use	3,130	447	
	DG capacity		6,480	Based on design capacity of 750 scfm
DG Production				
	Current DG Production	31,550	4,507	Based on May 2016 to April 2017 data which includes FOG from LES (deliveries ranged from 46,000 to 80,000 gal/week)
	Additional DG Production from 80,000 gal/week of FOG*	8,340	1,191	Based on Unit Energy Production factor of 0.10425 therms/gal FOG from RMC memo (EWPCF Alternative Fuels Receiving Facility Performance, May 2017). This factor corresponds to the FOG delivered by LES during 2016.
	Additional DG Production from 25,000 gal/week of LT Drip*	3,600	514	Based on Unit Energy Production factor of 0.14386 therms/gal LT Drip derived from April 2017 side-by-side testing that showed LT Drip produced 38% more DG per unit volume than FOG (note: the initial estimate of 50% more DG from LT Drip was adjusted to 38%).
	Additional DG Production from other FOG source (e.g., Atlas)			Can be calculated by multiplying volume delivered (gal/week) by Unit Energy Production factor (therms/gal). This factor would have to be determined through testing, or estimated based on factor for LES FOG.
	Additional DG Production from Spent Yeast (SY)			Can be calculated by multiplying volume delivered (gal/week) by Unit Energy Production factor (therms/gal). This factor would have to be determined through testing. Composition of SY (i.e., lipid, carbohydrate, and protein content) should be evaluated prior to testing.
	Additional DG Production from Food Waste Slurry			Can be calculated by multiplying volume delivered (gal/week) by Unit Energy Production factor (therms/gal). This factor would have to be determined through testing. Composition of EBS (i.e., lipid, carbohydrate, and protein content) should be evaluated prior to testing.

* The additional DG production estimated from an additional 80,000 gal /week of FOG and 25,000 gal/week of LT Drip (green cells; 11,940 therms/week) is about the same as the added DG demand from the Heat Dryer and Co-gen Engines (orange cells; 12,000 therms/week). An additional 12,000 therms/ week will increase the current DG production of approximately 4,500 therms/day to 6,200 therms/ day, which is approaching but still below the Flare's design capacity of 6,480 therms/day.

As noted in Table 3, the Heat Dryer and Co-gen Engines can use an additional 12,000 therms/week of DG to reach their maximum DG use (based on design and permit limits). This added DG demand can be met by co-digesting an additional 80,000 gal/week of FOG and 25,000 gal/week of Dewatered LT Drip. For completeness, Table 3 includes guidance on how DG production from FOG received from another source, spent yeast from a brewery, and FW slurry can be accounted for if these AFs are utilized.

The capacity for flaring DG is an important consideration because the flare needs to handle all the DG being produced in the event the Heat Dryer and Co-gen stop consuming DG. If an additional 12,000 therms/week of DG is produced (relative to May 2016 to April 2017 data), the total DG production is approaching the flare capacity. Therefore, an appropriate level of control over DG production via AF feed rates is needed to ensure DG production does not exceed the flare capacity. To reduce the risk of a DG venting incident, some agencies in Southern California have connected carbon canisters to the digester pressure relief valves to scrub hydrogen sulfide from any DG released, thus avoiding a permit violation during short-term increases in DG pressure.

4.3 Solids Dewatering and Drying

Highly biodegradable AFs like FOG and Dewatered LT Drip do not result in additional solids to be dewatered. In fact, they can lead to enhanced digestion of the wastewater solids, resulting in an overall reduction of solids to dewater relative to no AF co-digestion. This may not be the case for other AFs (e.g., FW slurry and brewery spent yeast). Testing would be needed to determine the VSR of these AFs, and the resulting impact on the solids content of the digested sludge.

4.4 Centrate Quality

The impact of AF co-digestion on the quality of centrate (or other return streams) has not been reported widely. The co-digestion of nitrogen-rich AFs would likely increase the ammonia content of the centrate being returned to the head of the plant. This would be significant for a nitrifying plant. For a non-nitrifying plant like the EWPCF, the impact may be minor.

Since digestion at thermophilic temperature was mentioned previously as an option to increase the VS/organic loading capacity, it should be noted that thermophilic digestion typically has a negative impact on centrate quality in terms of solids and organic content. The digested sludge floc characteristics in thermophilic digestion result in a lower solids capture in the dewatering process.

5. RECOMMENDATIONS

Recommendations for the AF loading strategy and process monitoring are presented in this section.

5.1 Alternative Fuel Loading Strategy

The key to the AF loading strategy is the target for the additional DG to be produced. As described in Section 4, this target is about 12,000 therms/week. It is recommended to prioritize FOG and Dewatered LT Drip to achieve the DG production target since these AFs are the most effective at producing DG with little risk of causing digester instability. Also, FOG and Dewatered LT Drip are not expected to increase the solids loading to the dewatering process or degrade the quality of the centrate. The quantities of FOG and Dewatered LT Drip needed to produce about 12,000 therms/week are consistent with the reported availability of these AFs from current suppliers. Guidance has also been given that FOG from another supplier, in significant quantities that undergo more quality control, is readily available. A practical

concern of FOG injection is the potential for FOG to congeal and plug piping. Fortunately, the AFRF was designed with relatively short pipe runs and a hot water flush system to address this concern.
If the co-digestion of spent yeast and/or FW slurry is pursued, a thorough testing phase is recommended in which the loading rate of the AF is gradually ramped up to assess the process impacts. The main reasons for this are the potential for ammonia production in the digesters, and the potential to increase solids loading to dewatering and the dryer. A test period of three months or more in a digester dedicated to the co-digestion of the AF of interest is desirable to collect a representative body of data.

Before additional AF is received, an evaluation of the flare's ability to operate near its design capacity is recommended. Depending on this outcome, a determination can be made on whether the system's ability to respond to the various modes of failure will be acceptable if more DG is produced.

AF Strategy Summary:

- Prioritize FOG and Dewatered LT Drip to achieve target of 12,000 therms/week
- Evaluate flare's ability to operate near design capacity
- Testing phase recommended for spent yeast
- Testing phase recommended for FW slurry

5.2 Process Monitoring

The process monitoring parameters currently measured for the digestion system are comprehensive. These parameters and typical values are shown in Table 4.

Table 4 Typical Data for Digester Operation (May 2016 to April 2017)

Parameter	units	Average	Min	Max
Primary sludge to digesters	gal/day	166,402	146,869	189,562
Primary sludge TS	%	4.23	3.57	5.20
Primary sludge VS	%	86.78	82.60	87.85
TWAS to digesters	gal/day	84,279	77,889	95,341
TWAS TS	%	5.70	4.96	6.25
TWAS VS	%	80.10	78.00	82.40
Digester HRT	days	17.30	15.81	19.23
Digester Temperature	deg F	97.08	96.94	97.23
pH (digested sludge)	n/a	7.07	6.94	7.12
Alkalinity (digested sludge)	mg/L as CaCO3	4,834	4,438	5,283
VFA (digested sludge)	mg/L	226.00	165.00	276.00
NH3-N (digested sludge)	mg/L	n/a	n/a	n/a
VSR	%	54.66	46.62	60.21
Biogas production	cu ft/day	739,367	668,760	816,099
Methane content (digester gas)	%	58.60	55.37	61.34
H2S (digester gas)	ppm	180	100	275

The current monitoring should continue, and if an AF containing appreciable levels of nitrogen (e.g., protein) is co-digested, then monitoring the ammonia nitrogen concentration in the digested sludge (or centrate) is also recommended. When changes to the type of AF or changes to the loading rate are made, it is recommended to increase the frequency of measurements done in the lab from once per week to two or three times per week until the new steady state is reached (approximately 1 month). When considering an AF for co-digestion, characterizing the AF according to Table 5 is also recommended.

Table 5 Recommended AF Characterization Data

Parameter	units	Alternative Fuel Value	Notes/Comments
Source/AF Type	n/a		Describe the source of material
Quantity	gal/day		Provide the expected quantity of waste material
TS	%		Total Solids
VS	% of TS		Volatile Solids
TDS	mg/L		Total Dissolved Solids
COD (total)	mg/L		Total Chemical Oxygen Demand
COD (soluble)	mg/L		Soluble Chemical Oxygen Demand
pH	n/a		
Alkalinity	mg/L as $CaCO_3$		
VFA	mg/L		Volatile Acids
TN	mg/L		Total Nitrogen
TKN	mg/L		Total Kjeldahl Nitrogen
NH_3-N	mg/L		Ammonia Nitrogen
TOC	mg/L		Total Organic Carbon
Phosphate as P	mg/L		
Phosphorus (total)	mg/L		
Sulfide (total)	mg/L		
Sulfide (soluble)	mg/L		
H_2S	mg/L		Hydrogen Sulfide
Sulfate	mg/L		
Protein content	%		
Fat content	%		
Carbohydrates	%		
C:N	mass ratio		Carbon to Nitrogen Ratio
BMP	volume of methane per mass of VS		Biomethane Potential
Viscosity	centistokes (cSt)		kinematic viscosity or other measure of viscosity

Knowing the composition of the AF is important for understanding the potential for digester instability and determining initial loading rates for co-digestion. For example, three different AFs from a local brewery known as Raw Spent Yeast, Dewatered Spent Yeast, and Dewatered LT Drip (same AF mentioned in Section 1.2), were analyzed for the parameters shown in Table 5 (except BMP) in July 2017. The Dewatered Spent Yeast is the liquid fraction produced from a solids removal process on Raw Spent Yeast, and Dewatered LT Drip is the liquid fraction resulting from a solids removal process on LT Drip. The results of this analysis are presented in Table 6.

Table 6 Brewery Waste Characterization Data

Parameter	units	Alternative Fuel Value		
Source/AF Type	n/a	Raw Spent Yeast	Dewatered Spent Yeast	Dewatered LT Drip
Quantity	gal/day	-	-	-
TS	%	11	1.4	5.1
VS	% of TS	>99	86	98
TDS	mg/L	11,000	9,800	35,000
COD (total)	mg/L	110,000	50,000	59,000
COD (soluble)	mg/L	58,000	52,000	60,000
pH	n/a	4.4	5	4.8
Alkalinity	mg/L as CaCO3	ND	120	110
VFA	mg/L	2,100	660	227
TN	mg/L	1,200	360	340
TKN	mg/L	1,200	350	340
NH_3-N	mg/L	44.3	19.3	25.3
TOC	mg/L	24,000	11,000	15,000
Phosphate as P	mg/L	160	120	130
Phosphorus (total)	mg/L	370	100	140
Sulfide (total)	mg/L	ND	ND	ND
Sulfide (soluble)	mg/L	ND	ND	ND
H_2S	mg/L	ND	ND	ND
Sulfate	mg/L	210	190	240
Protein content	%	2.98	0.19	0.18
Fat content	%	1.17	0.4	0.18
Carbohydrates	%	8.76	1.02	4.22
C:N	mass ratio	13:1	27:1	4:1
BMP	volume of methane per mass of VS	-	-	-
Viscosity	Bostwick (cm @ 30 sec)	2.5	>23	>23

Based on the data in Table 6, the Dewatered Spent Yeast and Dewatered LT Drip have similar characteristics, which suggests their behavior as an AF in co-digestion would be similar. Relative to the brewery wastes that went through a solids removal process, the Raw Spent Yeast has a higher potential for causing digester instability due to the significantly higher protein content (i.e., 2.98% compared to less than 0.2%).

To ensure the composition of AFs stays within acceptable limits, the development of a specification for each type of AF is recommended to include in the contract with the AF supplier. An enforceable AF specification that defines all the appropriate limits for AF quality will add to the success of the co-digestion program.

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Attachment C: Pre-Processed SSO Characteristics

Detailed Summary of food waste characteristics from LACSD

ITEM	VALUE	REFERENCE
pH	3.0 – 7.0	LACSD SSO SPECIFICATION
Volatile Acids (Acetic Acid Equivalents)	Less than 8,000 mg/L	LACSD SSO SPECIFICATION
Total Solids	12.0 – 15.0%	LACSD SSO SPECIFICATION
Volatile Solids (% of Total Solids)	85 – 95%	LACSD SSO SPECIFICATION
Total COD	Greater than 180,000 mg/L	LACSD SSO SPECIFICATION
Total BOD	Greater than 80,000 mg/L	LACSD SSO SPECIFICATION
Specific Gravity@25 degC	0.95 – 1.10	LACSD SSO SPECIFICATION
Kinematic Viscosity@25 degC	Less than 200 cps	LACSD SSO SPECIFICATION
Ammonia as Nitrogen (NH3-N)	Less than 600 mg/L	LACSD SSO SPECIFICATION
Total Kjeldahl Nitrogen (TKN)	Less than 7,500 mg/L	LACSD SSO SPECIFICATION
Total Carbon	Greater than 9,000 mg/L	LACSD SSO SPECIFICATION
Electrical Conductivity	Less than 15 millimho/cm	LACSD SSO SPECIFICATION
Arsenic	Less than 1 mg/L	LACSD SSO SPECIFICATION
Calcium	Less than 3,000 mg/L	LACSD SSO SPECIFICATION
Chloride	Less than 3,000 mg/L	LACSD SSO SPECIFICATION
Chromium	Less than 2 mg/L	LACSD SSO SPECIFICATION
Magnesium	Less than 500 mg/L	LACSD SSO SPECIFICATION
Mercury	Less than 1 mg/L	LACSD SSO SPECIFICATION
Nickel	Less than 5 mg/L	LACSD SSO SPECIFICATION
Potassium	Less than 3,000 mg/L	LACSD SSO SPECIFICATION
Sodium	Less than 3,000 mg/L	LACSD SSO SPECIFICATION
Total Heavy Metals (Ag, As, Ba, Cd, Co, Cr, Cu, Hg, Mo, Ni, Pb, Sb, Se, Ti Sr, Sn, V, and Zn)	Less than 50 mg/L	LACSD SSO SPECIFICATION
Specific Heavy Metal Limits		
Cadmium (Cd)	1 mg/L	Ordinance OCSD-48
Chromium (Cr)	35 mg/L	Ordinance OCSD-48
Copper (Cu)	25 mg/L	Ordinance OCSD-48
Lead (Pb)	10 mg/L	Ordinance OCSD-48
Nickel (Ni)	10 mg/L	Ordinance OCSD-48

ITEM	VALUE	REFERENCE
Zinc (Zn)	50 mg/L	Ordinance OCSD-48
Physical Contamination [1] (greater than 4 millimeters)	0.5% by dry weight	Title 14 -Section 17868.3.1 – Physical Contamination Limits
Film Plastic (greater than 4 millimeters)	20% by dry weight of Physical Contamination	Title 14 -Section 17868.3.1 – Physical Contamination Limits

Note:

1. "Physical Contaminants" means human-made inert products contained within feedstocks, including, but not limited to, glass, metal, and plastic (Title 14 Section 17381).

Attachment D: Co-digestion Capacity Calculations

Brown AND Caldwell

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-001
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - Service Condition		

Co-digestion Assessment

Mesophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.18	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	97	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS$_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Mesophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	3.90	3.90	3.90	3.90	3.90	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	19	15	14	13	12	
Base OLR (lbsVS/d-cf)	0.13	0.16	0.17	0.18	0.20	
Hydraulic Capacity (HC) (gpd)	50,570	4,478	-9,549	-29,589	-69,669	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	43,019	3,810	-8,124	-25,171	-59,266	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	26,353	11,591	7,098	679	-12,158	*Difference between max OLR (0.18 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Hydraulic	No Capacity	No Capacity	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	26,353	3,810	0	0	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	26,353	3,810	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	26,353	3,810	0	0	0	
SSO Total Solids Load (lb-TS/day)	31,004	4,482	0	0	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	31,004	4,482	0	0	0	
SSO (lb-wet/day)	258,364	37,349	0	0	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	258,364	37,349	0	0	0	
SSO (wtpd)	129	19	0	0	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	129	19	0	0	0	
SSO (gpd)	30,979	4,478	0	0	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	30,979	4,478	0	0	0	
Total Solids, Total Solids Load (lb-TS/d)	111,024	101,989	102,829	110,432	125,638	
Total Solids, Volatile Solids Load (lb-VS/d)	93,730	85,949	86,632	93,051	105,887	
Total Flow (gpd)	240,076	259,667	269,216	289,256	329,335	
Primary sludge percent of VS Load (%)	45%	60%	63%	63%	63%	

WAS percent of VS Load (%)	24%	32%	34%	34%	34%	
FOG percent of VS Load (%)	3%	4%	4%	3%	3%	
SSO percent of VS Load (%)	28%	4%	0%	0%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	16	15	14	13	12	
Co-Digestion OLR (lbs-VS/d-cf)	0.18	0.17	0.17	0.18	0.20	
Process Check	OK	OK	No Capacity	No Capacity	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	23,718	3,429	0	0	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	64,276	52,654	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	240,076	259,667	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	46,748	49,335	50,966	54,801	62,470	
Volatile Solids (Lbs-VS/d)	29,454	33,295	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	63%	67%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	44,411	46,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	101	107	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	426,920	61,716	0	0	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	1,148,850	937,927	923,166	990,244	1,124,401	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	31,004	4,482	0	0	0	
SSO Volatile Solids Load (lb-VS/d)	26,353	3,810	0	0	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.000	0.000	0.000	
SSO Ammonium-N Load (lb-N/day)	1,260	182	0	0	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	36	36	36	36	36	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.47	9.47	9.47	9.47	9.47	
Total Nitrogen (lb-N/d)	3,380	2,784	2,748	2,958	3,377	
Flow to Digeseter (MGD)	0.24	0.26	0.27	0.29	0.33	
Ammonium-N Conc. (mg/L)	1,688	1,285	1,224	1,226	1,230	
Ammonium-N (molar)	0.12	0.09	0.09	0.09	0.09	
Log Ammonia-N	-3.34	-3.46	-3.48	-3.48	-3.48	
Ammonia Concentration (mg-NH_3-N/L)	6.44	4.90	4.67	4.68	4.69	
Ammonia Concentration (mg-NH_3/L)	7.83	5.97	5.68	5.69	5.71	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

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Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-001
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - Service Condition		

Co-digestion Assessment

Mesophilic Digestion with Digesters 1-6

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.18	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	97	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Mesophilic Digestion with Digesters 1-6 Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	4.75	4.75	4.75	4.75	4.75	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	23	19	18	16	14	
Base OLR (lbsVS/d-cf)	0.11	0.13	0.14	0.15	0.17	
Hydraulic Capacity (HC) (gpd)	107,570	61,478	47,451	27,411	-12,669	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	91,507	52,298	40,365	23,318	-10,777	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	46,928	32,166	27,673	21,254	8,417	*Difference between max OLR (0.18 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	46,928	32,166	27,673	21,254	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	46,928	32,166	27,673	21,254	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	46,928	32,166	27,673	21,254	0	
SSO Total Solids Load (lb-TS/day)	55,209	37,842	32,556	25,005	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	55,209	37,842	32,556	25,005	0	
SSO (lb-wet/day)	460,078	315,349	271,301	208,375	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	460,078	315,349	271,301	208,375	0	
SSO (wtpd)	230	158	136	104	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	230	158	136	104	0	
SSO (gpd)	55,165	37,812	32,530	24,985	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	55,165	37,812	32,530	24,985	0	
Total Solids, Total Solids Load (lb-TS/d)	135,230	135,349	135,385	135,437	125,638	
Total Solids, Volatile Solids Load (lb-VS/d)	114,305	114,305	114,305	114,305	105,887	
Total Flow (gpd)	264,262	293,000	301,746	314,241	329,335	
Primary sludge percent of VS Load (%)	37%	45%	48%	51%	63%	
WAS percent of VS Load (%)	20%	24%	25%	27%	34%	
FOG percent of VS Load (%)	3%	3%	3%	3%	3%	
SSO percent of VS Load (%)	41%	28%	24%	19%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	18	16	16	15	14	

Co-Digestion OLR (lbs-VS/d-cf)	0.18	0.18	0.18	0.18	0.17	
Process Check	OK	OK	OK	OK	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	42,235	28,949	24,905	19,129	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	82,793	78,174	76,769	74,761	63,169	
Total Sludge Effluent (gpd)	264,262	293,000	301,746	314,241	329,335	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	52,437	57,175	58,617	60,677	62,470	
Volatile Solids (Lbs-VS/d)	31,512	36,130	37,536	39,544	42,719	
Total Solids (% TS)	2.4%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	60%	63%	64%	65%	68%	
Dewatered Solids (Lbs-TS/d)	49,815	54,316	55,686	57,643	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	113	123	127	131	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	760,233	521,082	448,297	344,318	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	1,482,163	1,397,293	1,371,463	1,334,563	1,124,401	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	55,209	37,842	32,556	25,005	0	
SSO Volatile Solids Load (lb-VS/d)	46,928	32,166	27,673	21,254	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.000	
SSO Ammonium-N Load (lb-N/day)	2,244	1,538	1,323	1,016	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (If applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	36	36	36	36	36	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.47	9.47	9.47	9.47	9.47	
Total Nitrogen (lb-N/d)	4,363	4,140	4,071	3,974	3,377	
Flow to Digeseter (MGD)	0.26	0.29	0.30	0.31	0.33	
Ammonium-N Conc. (mg/L)	1,980	1,694	1,618	1,516	1,230	
Ammonium-N (molar)	0.14	0.12	0.12	0.11	0.09	
Log Ammonia-N	-3.27	-3.34	-3.36	-3.38	-3.48	
Ammonia Concentration (mg-NH_3-N/L)	7.55	6.46	6.17	5.79	4.69	
Ammonia Concentration (mg-NH_3/L)	9.19	7.86	7.51	7.04	5.71	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Brown AND Caldwell

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-001
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - Service Condition		

Co-digestion Assessment

15 day Thermophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 15 day Thermophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	3.90	3.90	3.90	3.90	3.90	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	19	15	14	13	12	
Base OLR (lbsVS/d-cf)	0.13	0.16	0.17	0.18	0.20	
Hydraulic Capacity (HC) (gpd)	50,570	4,478	-9,549	-29,589	-69,669	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	43,019	3,810	-8,124	-25,171	-59,266	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	114,876	100,113	95,621	89,202	76,365	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Hydraulic	Hydraulic	No Capacity	No Capacity	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	43,019	3,810	0	0	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	43,019	3,810	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	43,019	3,810	0	0	0	
SSO Total Solids Load (lb-TS/day)	50,610	4,482	0	0	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	50,610	4,482	0	0	0	
SSO (lb-wet/day)	421,751	37,349	0	0	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	421,751	37,349	0	0	0	
SSO (wtpd)	211	19	0	0	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	211	19	0	0	0	
SSO (gpd)	50,570	4,478	0	0	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	50,570	4,478	0	0	0	
Total Solids, Total Solids Load (lb-TS/d)	130,631	101,989	102,829	110,432	125,638	
Total Solids, Volatile Solids Load (lb-VS/d)	110,395	85,949	86,632	93,051	105,887	
Total Flow (gpd)	259,667	259,667	269,216	289,256	329,335	
Primary sludge percent of VS Load (%)	38%	60%	63%	63%	63%	

WAS percent of VS Load (%)	20%	32%	34%	34%	34%	
FOG percent of VS Load (%)	3%	4%	4%	3%	3%	
SSO percent of VS Load (%)	39%	4%	0%	0%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	15	15	14	13	12	
Co-Digestion OLR (lbs-VS/d-cf)	0.21	0.17	0.17	0.18	0.20	
Process Check	OK	OK	No Capacity	No Capacity	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	38,717	3,429	0	0	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	79,275	52,654	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	259,667	259,667	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	51,356	49,335	50,966	54,801	62,470	
Volatile Solids (Lbs-VS/d)	31,121	33,295	34,769	37,419	42,719	
Total Solids (% TS)	2.4%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	61%	67%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	48,788	46,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	111	107	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	696,901	61,716	0	0	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	1,418,832	937,927	923,166	990,244	1,124,401	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	50,610	4,482	0	0	0	
SSO Volatile Solids Load (lb-VS/d)	43,019	3,810	0	0	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.000	0.000	0.000	
SSO Ammonium-N Load (lb-N/day)	2,057	182	0	0	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	4,176	2,784	2,748	2,958	3,377	
Flow to Digeseter (MGD)	0.26	0.26	0.27	0.29	0.33	
Ammonium-N Conc. (mg/L)	1,929	1,285	1,224	1,226	1,230	
Ammonium-N (molar)	0.14	0.09	0.09	0.09	0.09	
Log Ammonia-N	-3.03	-3.21	-3.23	-3.23	-3.23	
Ammonia Concentration (mg-NH_3-N/L)	12.96	8.64	8.22	8.24	8.26	
Ammonia Concentration (mg-NH_3/L)	15.76	10.51	10.00	10.02	10.05	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-001
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - Service Condition		

Co-digestion Assessment

15 day Thermophilic Digestion with All digesters in service

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 15 day Thermophilic Digestion with All digesters in service Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	4.75	4.75	4.75	4.75	4.75	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	23	19	18	16	14	
Base OLR (lbsVS/d-cf)	0.11	0.13	0.14	0.15	0.17	
Hydraulic Capacity (HC) (gpd)	107,570	61,478	47,451	27,411	-12,669	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	91,507	52,298	40,365	23,318	-10,777	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	154,882	140,120	135,627	129,209	116,372	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Hydraulic	Hydraulic	Hydraulic	Hydraulic	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	91,507	52,298	40,365	23,318	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	91,507	52,298	40,365	23,318	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	91,507	52,298	40,365	23,318	0	
SSO Total Solids Load (lb-TS/day)	107,656	61,528	47,489	27,433	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	107,656	61,528	47,489	27,433	0	
SSO (lb-wet/day)	897,131	512,729	395,738	228,607	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	897,131	512,729	395,738	228,607	0	
SSO (wtpd)	449	256	198	114	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	449	256	198	114	0	
SSO (gpd)	107,570	61,478	47,451	27,411	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	107,570	61,478	47,451	27,411	0	
Total Solids, Total Solids Load (lb-TS/d)	187,676	159,035	150,318	137,865	125,638	
Total Solids, Volatile Solids Load (lb-VS/d)	158,884	134,438	126,997	116,368	105,887	
Total Flow (gpd)	316,667	316,667	316,667	316,667	329,335	
Primary sludge percent of VS Load (%)	26%	38%	43%	50%	63%	
WAS percent of VS Load (%)	14%	21%	23%	27%	34%	
FOG percent of VS Load (%)	2%	2%	3%	3%	3%	
SSO percent of VS Load (%)	58%	39%	32%	20%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	15	15	15	15	14	

Co-Digestion OLR (lbs-VS/d-cf)	0.25	0.21	0.20	0.18	0.17	
Process Check	OK	OK	OK	OK	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	82,357	47,069	36,329	20,986	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	122,915	96,294	88,192	76,618	63,169	
Total Sludge Effluent (gpd)	316,667	316,667	316,667	316,667	329,335	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	64,762	62,741	62,126	61,247	62,470	
Volatile Solids (Lbs-VS/d)	35,970	38,144	38,805	39,751	42,719	
Total Solids (% TS)	2.5%	2.4%	2.4%	2.3%	2.3%	
Volatile Solids (% VS)	56%	61%	62%	65%	68%	
Dewatered Solids (Lbs-TS/d)	61,524	59,604	59,020	58,185	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	140	135	134	132	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	1,482,419	847,234	653,917	377,750	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	2,204,349	1,723,445	1,577,083	1,367,994	1,124,401	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	107,656	61,528	47,489	27,433	0	
SSO Volatile Solids Load (lb-VS/d)	91,507	52,298	40,365	23,318	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.000	
SSO Ammonium-N Load (lb-N/day)	4,375	2,501	1,930	1,115	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (If applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	6,495	5,102	4,678	4,073	3,377	
Flow to Digeseter (MGD)	0.32	0.32	0.32	0.32	0.33	
Ammonium-N Conc. (mg/L)	2,459	1,932	1,771	1,542	1,230	
Ammonium-N (molar)	0.18	0.14	0.13	0.11	0.09	
Log Ammonia-N	-2.93	-3.03	-3.07	-3.13	-3.23	
Ammonia Concentration (mg-NH_3-N/L)	16.52	12.98	11.90	10.36	8.26	
Ammonia Concentration (mg-NH_3/L)	20.10	15.79	14.48	12.60	10.05	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-001
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - Service Condition		

Co-digestion Assessment

10 day Thermophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	10	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS_d)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

#REF!

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	3.90	3.90	3.90	3.90	3.90	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	19	15	14	13	12	
Base OLR (lbsVS/d-cf)	0.13	0.16	0.17	0.18	0.20	
Hydraulic Capacity (HC) (gpd)	180,403	134,312	120,284	100,244	60,165	*Assumes the minimum allowable HRT 10 days*
HC as Equivalent VS Load (lb-VS/day)	153,465	114,256	102,323	85,276	51,181	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	114,876	100,113	95,621	89,202	76,365	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Hydraulic	Hydraulic	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	114,876	100,113	95,621	85,276	51,181	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	114,876	100,113	95,621	85,276	51,181	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	114,876	100,113	95,621	85,276	51,181	
SSO Total Solids Load (lb-TS/day)	135,148	117,780	112,495	100,324	60,213	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	135,148	117,780	112,495	100,324	60,213	
SSO (lb-wet/day)	1,126,233	981,504	937,456	836,037	501,774	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,126,233	981,504	937,456	836,037	501,774	
SSO (wtpd)	563	491	469	418	251	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	563	491	469	418	251	
SSO (gpd)	135,040	117,686	112,405	100,244	60,165	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	135,040	117,686	112,405	100,244	60,165	
Total Solids, Total Solids Load (lb-TS/d)	215,168	215,288	215,324	210,757	185,851	
Total Solids, Volatile Solids Load (lb-VS/d)	182,253	182,253	182,253	178,326	157,068	
Total Flow (gpd)	344,137	372,875	381,621	389,500	389,500	
Primary sludge percent of VS Load (%)	23%	28%	30%	33%	43%	

WAS percent of VS Load (%)	12%	15%	16%	18%	23%	
FOG percent of VS Load (%)	2%	2%	2%	2%	2%	
SSO percent of VS Load (%)	63%	55%	52%	48%	33%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	11	10	10	10	10	
Co-Digestion OLR (lbs-VS/d-cf)	0.35	0.35	0.35	0.34	0.30	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	103,388	90,102	86,058	76,748	46,063	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	143,946	139,327	137,922	132,380	109,232	
Total Sludge Effluent (gpd)	344,137	372,875	381,621	389,500	389,500	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	71,222	75,960	77,402	78,377	76,620	
Volatile Solids (Lbs-VS/d)	38,307	42,925	44,331	45,946	47,837	
Total Solids (% TS)	2.5%	2.4%	2.4%	2.4%	2.4%	
Volatile Solids (% VS)	54%	57%	57%	59%	62%	
Dewatered Solids (Lbs-TS/d)	67,661	72,162	73,532	74,458	72,789	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	154	164	167	169	165	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	1,860,988	1,621,837	1,549,052	1,381,467	829,132	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	2,582,918	2,498,048	2,472,218	2,371,711	1,953,534	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	135,148	117,780	112,495	100,324	60,213	
SSO Volatile Solids Load (lb-VS/d)	114,876	100,113	95,621	85,276	51,181	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	5,492	4,787	4,572	4,077	2,447	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	7,612	7,388	7,320	7,035	5,824	
Flow to Digeseter (MGD)	0.34	0.37	0.38	0.39	0.39	
Ammonium-N Conc. (mg/L)	2,652	2,376	2,300	2,166	1,793	
Ammonium-N (molar)	0.19	0.17	0.16	0.15	0.13	
Log Ammonia-N	-2.90	-2.94	-2.96	-2.98	-3.07	
Ammonia Concentration (mg-NH_3-N/L)	17.82	15.96	15.45	14.55	12.05	
Ammonia Concentration (mg-NH_3/L)	21.67	19.42	18.80	17.70	14.65	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-001
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - Service Condition		

Co-digestion Assessment

10 day Thermophilic Digestion with All digesters in service

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	10	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 10 day Thermophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	4.75	4.75	4.75	4.75	4.75	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	23	19	18	16	14	
Base OLR (lbsVS/d-cf)	0.11	0.13	0.14	0.15	0.17	
Hydraulic Capacity (HC) (gpd)	265,903	219,812	205,784	185,744	145,665	*Assumes the minimum allowable HRT 10 days*
HC as Equivalent VS Load (lb-VS/day)	226,198	186,989	175,056	158,009	123,914	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	154,882	140,120	135,627	129,209	116,372	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	154,882	140,120	135,627	129,209	116,372	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	154,882	140,120	135,627	129,209	116,372	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	154,882	140,120	135,627	129,209	116,372	
SSO Total Solids Load (lb-TS/day)	182,215	164,847	159,561	152,010	136,908	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	182,215	164,847	159,561	152,010	136,908	
SSO (lb-wet/day)	1,518,456	1,373,726	1,329,678	1,266,753	1,140,901	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,518,456	1,373,726	1,329,678	1,266,753	1,140,901	
SSO (wtpd)	759	687	665	633	570	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	759	687	665	633	570	
SSO (gpd)	182,069	164,715	159,434	151,889	136,799	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	182,069	164,715	159,434	151,889	136,799	
Total Solids, Total Solids Load (lb-TS/d)	262,235	262,354	262,391	262,443	262,546	
Total Solids, Volatile Solids Load (lb-VS/d)	222,259	222,259	222,259	222,259	222,259	
Total Flow (gpd)	391,166	419,904	428,650	441,145	466,134	
Primary sludge percent of VS Load (%)	19%	23%	24%	26%	30%	
WAS percent of VS Load (%)	10%	12%	13%	14%	16%	
FOG percent of VS Load (%)	1%	1%	1%	1%	1%	
SSO percent of VS Load (%)	70%	63%	61%	58%	52%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	12	11	11	11	10	

Co-Digestion OLR (lbs-VS/d-cf)	0.35	0.35	0.35	0.35	0.35	
Process Check	OK	OK	OK	OK	OK	
Table X-X: Existing Mesophilic Solids and Biogas Production						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	
Table X-X: Mesophilic Co-digestion Solids and Biogas Production						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	139,394	126,108	122,064	116,288	104,735	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	179,952	175,333	173,928	171,920	167,903	
Total Sludge Effluent (gpd)	391,166	419,904	428,650	441,145	466,134	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	82,283	87,021	88,463	90,523	94,643	
Volatile Solids (Lbs-VS/d)	42,307	46,926	48,332	50,340	54,356	
Total Solids (% TS)	2.5%	2.5%	2.5%	2.5%	2.4%	
Volatile Solids (% VS)	51%	54%	55%	56%	57%	
Dewatered Solids (Lbs-TS/d)	78,169	82,670	84,040	85,997	89,911	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	178	188	191	195	204	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	2,509,096	2,269,946	2,197,161	2,093,182	1,885,225	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	3,231,027	3,146,156	3,120,326	3,083,426	3,009,626	
Table X-X: Nutrient Loading - Ammonia-N Estimates						
HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	182,215	164,847	159,561	152,010	136,908	
SSO Volatile Solids Load (lb-VS/d)	154,882	140,120	135,627	129,209	116,372	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	7,405	6,699	6,485	6,178	5,564	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	9,525	9,301	9,233	9,136	8,941	
Flow to Digeseter (MGD)	0.39	0.42	0.43	0.44	0.47	
Ammonium-N Conc. (mg/L)	2,920	2,656	2,583	2,483	2,300	
Ammonium-N (molar)	0.21	0.19	0.18	0.18	0.16	
Log Ammonia-N	-2.85	-2.89	-2.91	-2.92	-2.96	
Ammonia Concentration (mg-NH_3-N/L)	19.62	17.85	17.35	16.68	15.45	
Ammonia Concentration (mg-NH_3/L)	23.86	21.71	21.11	20.29	18.80	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-001
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - Service Condition		

Co-digestion Assessment

Thermal Hydrolysis with Mesophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	12	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.4	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1	Percent Solids Content of Digester Feed	9%	Assumed	Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	102	Assumed	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS_d)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO		Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Thermal Hydrolysis with Mesophilic Digestion Feed Assessment						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	3.90	3.90	3.90	3.90	3.90	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	106,609	129,906	136,996	147,125	167,384	
Total Percent Solids Load (%)	9.0%	9.0%	9.0%	9.0%	9.0%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	37	30	28	26	23	
Base OLR (lbsVS/d-cf)	0.13	0.16	0.17	0.18	0.20	
Hydraulic Capacity (HC) (gpd)	217,975	194,678	187,587	177,458	157,200	*Assumes the minimum allowable HRT 12 days*
HC as Equivalent VS Load (lb-VS/day)	185,427	165,608	159,577	150,960	133,726	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	140,912	126,150	121,657	115,238	102,401	*Difference between max OLR (0.4 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	140,912	126,150	121,657	115,238	102,401	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	140,912	126,150	121,657	115,238	102,401	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	140,912	126,150	121,657	115,238	102,401	
SSO Total Solids Load (lb-TS/day)	165,779	148,411	143,125	135,574	120,472	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	165,779	148,411	143,125	135,574	120,472	
SSO (lb-wet/day)	1,381,489	1,236,760	1,192,712	1,129,786	1,003,934	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,381,489	1,236,760	1,192,712	1,129,786	1,003,934	
SSO (wtpd)	691	618	596	565	502	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	691	618	596	565	502	
SSO Digester Feed (gpd)	220,862	197,723	190,681	180,621	160,501	*Assume 9% TS*
HSOW No. 2 (gpd)	0	0	0	0	0	*Assume 9% TS*
SSO Digester Feed(gpd)	220,862	197,723	190,681	180,621	160,501	*Assume 9% TS*
SSO As Received(gpd)	165,646	148,293	143,011	135,466	120,376	*Assume 12% TS*
HSOW No. 2 (gpd)	0	0	0	0	0	*Assume 12% TS*
SSO As Received (gpd)	165,646	148,293	143,011	135,466	120,376	*Assume 12% TS*
Total Solids, Total Solids Load (lb-TS/d)	245,799	245,918	245,955	246,007	246,110	

Total Solids, Volatile Solids Load (lb-VS/d)	208,289	208,289	208,289	208,289	208,289	
Total Flow (gpd)	327,470	327,629	327,678	327,747	327,885	
Primary sludge percent of VS Load (%)	20%	25%	26%	28%	32%	
WAS percent of VS Load (%)	11%	13%	14%	15%	17%	
FOG percent of VS Load (%)	2%	2%	2%	2%	2%	
SSO percent of VS Load (%)	68%	61%	58%	55%	49%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	12	12	12	12	12	
Co-Digestion OLR (lbs-VS/d-cf)	0.40	0.40	0.40	0.40	0.40	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	106,609	129,906	136,996	147,125	167,384	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	4.4%	4.5%	4.5%	4.5%	4.5%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	126,821	113,535	109,491	103,714	92,161	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	167,379	162,760	161,354	159,346	155,330	
Total Sludge Effluent (gpd)	327,470	327,629	327,678	327,747	327,885	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	78,421	83,159	84,601	86,661	90,781	
Volatile Solids (Lbs-VS/d)	40,910	45,529	46,935	48,943	52,959	
Total Solids (% TS)	2.9%	3.0%	3.1%	3.2%	3.3%	
Volatile Solids (% VS)	52%	55%	55%	56%	58%	
Dewatered Solids (Lbs-TS/d)	74,500	79,001	80,371	82,328	86,242	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	169	180	183	187	196	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	2,282,773	2,043,622	1,970,837	1,866,858	1,658,901	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	3,004,703	2,919,833	2,894,003	2,857,103	2,783,303	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	165,779	148,411	143,125	135,574	120,472	
SSO Volatile Solids Load (lb-VS/d)	140,912	126,150	121,657	115,238	102,401	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	6,737	6,032	5,817	5,510	4,896	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	39	39	39	39	39	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.45	9.45	9.45	9.45	9.45	
Total Nitrogen (lb-N/d)	8,857	8,633	8,565	8,468	8,273	
Flow to Digeseter (MGD)	0.33	0.33	0.33	0.33	0.33	
Ammonium-N Conc. (mg/L)	3,243	3,160	3,134	3,098	3,025	
Ammonium-N (molar)	0.23	0.23	0.22	0.22	0.22	
Log Ammonia-N	-3.04	-3.05	-3.05	-3.06	-3.07	
Ammonia Concentration (mg-NH_3-N/L)	12.91	12.58	12.48	12.33	12.04	
Ammonia Concentration (mg-NH_3/L)	15.70	15.30	15.18	15.00	14.65	
Ammonia Toxcitiy Check	Toxic	Toxic	Toxic	Toxic	Toxic	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-002
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - Service Condition		

Co-digestion Assessment

Mesophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.18	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	97	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Mesophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	3.90	3.90	3.90	3.90	3.90	*Service condition assumes largest digester is out of service with the active volume of each digeser reduc*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	15	12	11	11	9	
Base OLR (lbsVS/d-cf)	0.16	0.20	0.21	0.23	0.26	
Hydraulic Capacity (HC) (gpd)	-6,142	-65,277	-83,274	-108,985	-160,407	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	-5,225	-55,530	-70,840	-92,711	-136,455	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	8,015	-10,965	-16,741	-24,994	-41,498	*Difference between max OLR (0.18 lbs-VS/cf-d) and current load*
Process Limitation	No Capacity	No Capacity	No Capacity	No Capacity	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	0	0	0	0	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	0	0	0	0	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO (lb-wet/day)	0	0	0	0	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	0	0	0	0	0	
SSO (wtpd)	0	0	0	0	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	0	0	0	0	0	
SSO (gpd)	0	0	0	0	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	0	0	0	0	0	
Total Solids, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Total Solids, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Total Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	

SSO percent of VS Load (%)	0%	0%	0%	0%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	15	12	11	11	9	
Co-Digestion OLR (lbs-VS/d-cf)	0.16	0.20	0.21	0.23	0.26	
Process Check	OK	No Capacity	No Capacity	No Capacity	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	0	0	0	0	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	0	0	0	0	0	
SSO Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
SSO Ammonium-N Load (lb-N/day)	0	0	0	0	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	36	36	36	36	36	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.47	9.47	9.47	9.47	9.47	
Total Nitrogen (lb-N/d)	2,709	3,326	3,514	3,783	4,320	
Flow to Digeseter (MGD)	0.27	0.32	0.34	0.37	0.42	
Ammonium-N Conc. (mg/L)	1,222	1,227	1,229	1,230	1,233	
Ammonium-N (molar)	0.09	0.09	0.09	0.09	0.09	
Log Ammonia-N	-3.48	-3.48	-3.48	-3.47	-3.47	
Ammonia Concentration (mg-NH_3-N/L)	4.66	4.68	4.69	4.69	4.70	
Ammonia Concentration (mg-NH_3/L)	5.67	5.70	5.70	5.71	5.72	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

ed to account for process inefficiencies.

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-002
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - Service Condition		

Co-digestion Assessment

Mesophilic Digestion with Digesters 1-6

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.18	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	97	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Mesophilic Digestion with Digesters 1-6 Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	4.75	4.75	4.75	4.75	4.75	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	18	15	14	13	11	
Base OLR (lbsVS/d-cf)	0.13	0.16	0.17	0.19	0.21	
Hydraulic Capacity (HC) (gpd)	50,858	-8,277	-26,274	-51,985	-103,407	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	43,264	-7,041	-22,351	-44,223	-87,966	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	28,590	9,610	3,834	-4,419	-20,923	*Difference between max OLR (0.18 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	No Capacity	No Capacity	No Capacity	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	28,590	0	0	0	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	28,590	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	28,590	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	33,635	0	0	0	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	33,635	0	0	0	0	
SSO (lb-wet/day)	280,295	0	0	0	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	280,295	0	0	0	0	
SSO (wtpd)	140	0	0	0	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	140	0	0	0	0	
SSO (gpd)	33,609	0	0	0	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	33,609	0	0	0	0	
Total Solids, Total Solids Load (lb-TS/d)	135,458	124,324	131,172	140,955	160,521	
Total Solids, Volatile Solids Load (lb-VS/d)	114,305	104,695	110,471	118,724	135,228	
Total Flow (gpd)	299,417	324,943	342,941	368,652	420,073	
Primary sludge percent of VS Load (%)	46%	62%	62%	62%	63%	
WAS percent of VS Load (%)	26%	35%	35%	35%	35%	
FOG percent of VS Load (%)	3%	3%	3%	3%	2%	
SSO percent of VS Load (%)	25%	0%	0%	0%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	16	15	14	13	11	

Co-Digestion OLR (lbs-VS/d-cf)	0.18	0.16	0.17	0.19	0.21	
Process Check	OK	OK	No Capacity	No Capacity	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	25,731	0	0	0	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	76,913	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	299,417	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	58,545	62,031	65,497	70,450	80,354	
Volatile Solids (Lbs-VS/d)	37,392	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	64%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	55,618	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	126	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	463,160	0	0	0	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	1,374,197	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	33,635	0	0	0	0	
SSO Volatile Solids Load (lb-VS/d)	28,590	0	0	0	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.000	0.000	0.000	0.000	
SSO Ammonium-N Load (lb-N/day)	1,367	0	0	0	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (If applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	36	36	36	36	36	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.47	9.47	9.47	9.47	9.47	
Total Nitrogen (lb-N/d)	4,076	3,326	3,514	3,783	4,320	
Flow to Digeseter (MGD)	0.30	0.32	0.34	0.37	0.42	
Ammonium-N Conc. (mg/L)	1,632	1,227	1,229	1,230	1,233	
Ammonium-N (molar)	0.12	0.09	0.09	0.09	0.09	
Log Ammonia-N	-3.35	-3.48	-3.48	-3.47	-3.47	
Ammonia Concentration (mg-NH_3-N/L)	6.23	4.68	4.69	4.69	4.70	
Ammonia Concentration (mg-NH_3/L)	7.57	5.70	5.70	5.71	5.72	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-002
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - Service Condition		

Co-digestion Assessment

15 day Thermophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 15 day Thermophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	3.90	3.90	3.90	3.90	3.90	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	15	12	11	11	9	
Base OLR (lbsVS/d-cf)	0.16	0.20	0.21	0.23	0.26	
Hydraulic Capacity (HC) (gpd)	-6,142	-65,277	-83,274	-108,985	-160,407	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	-5,225	-55,530	-70,840	-92,711	-136,455	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	96,538	77,558	71,781	63,529	47,025	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	No Capacity	No Capacity	No Capacity	No Capacity	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	0	0	0	0	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	0	0	0	0	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO (lb-wet/day)	0	0	0	0	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	0	0	0	0	0	
SSO (wtpd)	0	0	0	0	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	0	0	0	0	0	
SSO (gpd)	0	0	0	0	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	0	0	0	0	0	
Total Solids, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Total Solids, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Total Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	

WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
SSO percent of VS Load (%)	0%	0%	0%	0%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	15	12	11	11	9	
Co-Digestion OLR (lbs-VS/d-cf)	0.16	0.20	0.21	0.23	0.26	
Process Check	OK	No Capacity	No Capacity	No Capacity	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	0	0	0	0	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	0	0	0	0	0	
SSO Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
SSO Ammonium-N Load (lb-N/day)	0	0	0	0	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	2,709	3,326	3,514	3,783	4,320	
Flow to Digeseter (MGD)	0.27	0.32	0.34	0.37	0.42	
Ammonium-N Conc. (mg/L)	1,222	1,227	1,229	1,230	1,233	
Ammonium-N (molar)	0.09	0.09	0.09	0.09	0.09	
Log Ammonia-N	-3.23	-3.23	-3.23	-3.23	-3.23	
Ammonia Concentration (mg-NH_3-N/L)	8.21	8.25	8.26	8.27	8.28	
Ammonia Concentration (mg-NH_3/L)	9.99	10.03	10.04	10.05	10.08	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Brown AND Caldwell

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-002
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - Service Condition		

Co-digestion Assessment

15 day Thermophilic Digestion with All digesters in service

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 15 day Thermophilic Digestion with All digesters in service Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	4.75	4.75	4.75	4.75	4.75	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	18	15	14	13	11	
Base OLR (lbsVS/d-cf)	0.13	0.16	0.17	0.19	0.21	
Hydraulic Capacity (HC) (gpd)	50,858	-8,277	-26,274	-51,985	-103,407	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	43,264	-7,041	-22,351	-44,223	-87,966	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	136,545	117,565	111,788	103,536	87,031	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Hydraulic	No Capacity	No Capacity	No Capacity	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	43,264	0	0	0	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	43,264	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	43,264	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	50,899	0	0	0	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	50,899	0	0	0	0	
SSO (lb-wet/day)	424,158	0	0	0	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	424,158	0	0	0	0	
SSO (wtpd)	212	0	0	0	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	212	0	0	0	0	
SSO (gpd)	50,858	0	0	0	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	50,858	0	0	0	0	
Total Solids, Total Solids Load (lb-TS/d)	152,721	124,324	131,172	140,955	160,521	
Total Solids, Volatile Solids Load (lb-VS/d)	128,979	104,695	110,471	118,724	135,228	
Total Flow (gpd)	316,667	324,943	342,941	368,652	420,073	
Primary sludge percent of VS Load (%)	41%	62%	62%	62%	63%	
WAS percent of VS Load (%)	23%	35%	35%	35%	35%	
FOG percent of VS Load (%)	2%	3%	3%	3%	2%	
SSO percent of VS Load (%)	34%	0%	0%	0%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	15	15	14	13	11	

Co-Digestion OLR (lbs-VS/d-cf)	0.20	0.16	0.17	0.19	0.21	
Process Check	OK	OK	No Capacity	No Capacity	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	38,938	0	0	0	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	90,120	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	316,667	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	62,602	62,031	65,497	70,450	80,354	
Volatile Solids (Lbs-VS/d)	38,859	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.4%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	62%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	59,472	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	135	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	700,879	0	0	0	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	1,611,916	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	50,899	0	0	0	0	
SSO Volatile Solids Load (lb-VS/d)	43,264	0	0	0	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.000	0.000	0.000	0.000	
SSO Ammonium-N Load (lb-N/day)	2,069	0	0	0	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	4,777	3,326	3,514	3,783	4,320	
Flow to Digeseter (MGD)	0.32	0.32	0.34	0.37	0.42	
Ammonium-N Conc. (mg/L)	1,809	1,227	1,229	1,230	1,233	
Ammonium-N (molar)	0.13	0.09	0.09	0.09	0.09	
Log Ammonia-N	-3.06	-3.23	-3.23	-3.23	-3.23	
Ammonia Concentration (mg-NH_3-N/L)	12.15	8.25	8.26	8.27	8.28	
Ammonia Concentration (mg-NH_3/L)	14.78	10.03	10.04	10.05	10.08	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-002
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - Service Condition		

Co-digestion Assessment

10 day Thermophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	10	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 10 day Thermophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	3.90	3.90	3.90	3.90	3.90	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	15	12	11	11	9	
Base OLR (lbsVS/d-cf)	0.16	0.20	0.21	0.23	0.26	
Hydraulic Capacity (HC) (gpd)	123,692	64,557	46,559	20,848	-30,573	*Assumes the minimum allowable HRT 10 days*
HC as Equivalent VS Load (lb-VS/day)	105,222	54,917	39,607	17,735	-26,008	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	96,538	77,558	71,781	63,529	47,025	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Hydraulic	Hydraulic	Hydraulic	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	96,538	54,917	39,607	17,735	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	96,538	54,917	39,607	17,735	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	96,538	54,917	39,607	17,735	0	
SSO Total Solids Load (lb-TS/day)	113,574	64,608	46,596	20,865	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	113,574	64,608	46,596	20,865	0	
SSO (lb-wet/day)	946,451	538,403	388,303	173,875	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	946,451	538,403	388,303	173,875	0	
SSO (wtpd)	473	269	194	87	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	473	269	194	87	0	
SSO (gpd)	113,483	64,557	46,559	20,848	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	113,483	64,557	46,559	20,848	0	
Total Solids, Total Solids Load (lb-TS/d)	215,396	188,932	177,768	161,820	160,521	
Total Solids, Volatile Solids Load (lb-VS/d)	182,253	159,612	150,078	136,459	135,228	
Total Flow (gpd)	379,292	389,500	389,500	389,500	420,073	
Primary sludge percent of VS Load (%)	29%	41%	46%	54%	63%	

WAS percent of VS Load (%)	16%	23%	26%	30%	35%	
FOG percent of VS Load (%)	2%	2%	2%	2%	2%	
SSO percent of VS Load (%)	53%	34%	26%	13%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	10	10	10	10	9	
Co-Digestion OLR (lbs-VS/d-cf)	0.35	0.31	0.29	0.26	0.26	
Process Check	OK	OK	OK	OK	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	86,884	49,425	35,646	15,962	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	138,066	111,718	101,321	86,467	80,167	
Total Sludge Effluent (gpd)	379,292	389,500	389,500	389,500	420,073	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	77,330	77,214	76,447	75,353	80,354	
Volatile Solids (Lbs-VS/d)	44,187	47,894	48,758	49,992	55,061	
Total Solids (% TS)	2.4%	2.4%	2.4%	2.3%	2.3%	
Volatile Solids (% VS)	57%	62%	64%	66%	69%	
Dewatered Solids (Lbs-TS/d)	73,464	73,353	72,625	71,585	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	167	167	165	163	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	1,563,916	889,657	641,632	287,311	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	2,474,953	1,998,469	1,810,637	1,542,304	1,426,972	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	113,574	64,608	46,596	20,865	0	
SSO Volatile Solids Load (lb-VS/d)	96,538	54,917	39,607	17,735	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.000	
SSO Ammonium-N Load (lb-N/day)	4,616	2,626	1,894	848	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	7,324	5,952	5,408	4,631	4,320	
Flow to Digeseter (MGD)	0.38	0.39	0.39	0.39	0.42	
Ammonium-N Conc. (mg/L)	2,315	1,832	1,665	1,425	1,233	
Ammonium-N (molar)	0.17	0.13	0.12	0.10	0.09	
Log Ammonia-N	-2.95	-3.06	-3.10	-3.17	-3.23	
Ammonia Concentration (mg-NH_3-N/L)	15.56	12.31	11.19	9.58	8.28	
Ammonia Concentration (mg-NH_3/L)	18.92	14.97	13.60	11.65	10.08	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

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Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-002
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - Service Condition		

Co-digestion Assessment

10 day Thermophilic Digestion with All digesters in service

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	10	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 10 day Thermophilic Digestion with All digesters in service Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	4.75	4.75	4.75	4.75	4.75	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	18	15	14	13	11	
Base OLR (lbsVS/d-cf)	0.13	0.16	0.17	0.19	0.21	
Hydraulic Capacity (HC) (gpd)	209,192	150,057	132,059	106,348	54,927	*Assumes the minimum allowable HRT 10 days*
HC as Equivalent VS Load (lb-VS/day)	177,955	127,650	112,340	90,468	46,725	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	136,545	117,565	111,788	103,536	87,031	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Hydraulic	Hydraulic	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	136,545	117,565	111,788	90,468	46,725	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	136,545	117,565	111,788	90,468	46,725	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	136,545	117,565	111,788	90,468	46,725	
SSO Total Solids Load (lb-TS/day)	160,641	138,311	131,515	106,433	54,971	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	160,641	138,311	131,515	106,433	54,971	
SSO (lb-wet/day)	1,338,673	1,152,594	1,095,961	886,945	458,088	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,338,673	1,152,594	1,095,961	886,945	458,088	
SSO (wtpd)	669	576	548	443	229	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	669	576	548	443	229	
SSO (gpd)	160,512	138,201	131,410	106,348	54,927	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	160,512	138,201	131,410	106,348	54,927	
Total Solids, Total Solids Load (lb-TS/d)	262,463	262,635	262,687	247,388	215,492	
Total Solids, Volatile Solids Load (lb-VS/d)	222,259	222,259	222,259	209,192	181,953	
Total Flow (gpd)	426,321	463,144	474,351	475,000	475,000	
Primary sludge percent of VS Load (%)	24%	29%	31%	35%	47%	
WAS percent of VS Load (%)	13%	16%	17%	20%	26%	
FOG percent of VS Load (%)	1%	1%	1%	2%	2%	
SSO percent of VS Load (%)	61%	53%	50%	43%	26%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	11	10	10	10	10	

Co-Digestion OLR (lbs-VS/d-cf)	0.35	0.35	0.35	0.33	0.29	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	122,890	105,808	100,609	81,422	42,052	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	174,072	168,101	166,284	151,927	122,219	
Total Sludge Effluent (gpd)	426,321	463,144	474,351	475,000	475,000	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	88,391	94,534	96,403	95,461	93,272	
Volatile Solids (Lbs-VS/d)	48,187	54,158	55,976	57,265	59,733	
Total Solids (% TS)	2.5%	2.4%	2.4%	2.4%	2.4%	
Volatile Solids (% VS)	55%	57%	58%	60%	64%	
Dewatered Solids (Lbs-TS/d)	83,971	89,807	91,583	90,688	88,609	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	191	204	208	206	201	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	2,212,024	1,904,546	1,810,966	1,465,587	756,944	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0		0	0	0	
Total Biogas Production (scfd)	3,123,061	3,013,359	2,979,971	2,720,581	2,183,917	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	160,641	138,311	131,515	106,433	54,971	
SSO Volatile Solids Load (lb-VS/d)	136,545	117,565	111,788	90,468	46,725	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	6,529	5,621	5,345	4,326	2,234	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	9,237	8,947	8,859	8,108	6,554	
Flow to Digeseter (MGD)	0.43	0.46	0.47	0.48	0.48	
Ammonium-N Conc. (mg/L)	2,598	2,316	2,239	2,047	1,654	
Ammonium-N (molar)	0.19	0.17	0.16	0.15	0.12	
Log Ammonia-N	-2.90	-2.95	-2.97	-3.01	-3.10	
Ammonia Concentration (mg-NH_3-N/L)	17.46	15.56	15.05	13.75	11.12	
Ammonia Concentration (mg-NH_3/L)	21.23	18.93	18.30	16.73	13.52	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Brown AND Caldwell

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-002
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - Service Condition		

Co-digestion Assessment

Thermal Hydrolysis with Mesophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	12	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.4	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1	Percent Solids Content of Digester Feed	9%	Assumed	Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	102	Assumed	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Thermal Hydrolysis with Mesophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	3.90	3.90	3.90	3.90	3.90	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	135,655	165,632	174,756	187,790	213,857	
Total Percent Solids Load (%)	9.0%	9.0%	9.0%	9.0%	9.0%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	29	24	22	21	18	
Base OLR (lbsVS/d-cf)	0.16	0.20	0.21	0.23	0.26	
Hydraulic Capacity (HC) (gpd)	188,929	158,951	149,827	136,794	110,726	*Assumes the minimum allowable HRT 12 days*
HC as Equivalent VS Load (lb-VS/day)	160,718	135,217	127,455	116,368	94,192	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	122,574	103,594	97,817	89,565	73,061	*Difference between max OLR (0.4 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	122,574	103,594	97,817	89,565	73,061	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	122,574	103,594	97,817	89,565	73,061	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	122,574	103,594	97,817	89,565	73,061	
SSO Total Solids Load (lb-TS/day)	144,205	121,875	115,079	105,371	85,954	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	144,205	121,875	115,079	105,371	85,954	
SSO (lb-wet/day)	1,201,707	1,015,628	958,995	878,091	716,283	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,201,707	1,015,628	958,995	878,091	716,283	
SSO (wtpd)	601	508	479	439	358	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	601	508	479	439	358	
SSO Digester Feed (gpd)	192,119	162,371	153,317	140,382	114,514	*Assume 9% TS*
HSOW No. 2 (gpd)	0	0	0	0	0	*Assume 9% TS*
SSO Digester Feed(gpd)	192,119	162,371	153,317	140,382	114,514	*Assume 9% TS*
SSO As Received(gpd)	144,090	121,778	114,987	105,287	85,885	*Assume 12% TS*
HSOW No. 2 (gpd)	0	0	0	0	0	*Assume 12% TS*
SSO As Received (gpd)	144,090	121,778	114,987	105,287	85,885	*Assume 12% TS*
Total Solids, Total Solids Load (lb-TS/d)	246,027	246,199	246,251	246,326	246,475	

Total Solids, Volatile Solids Load (lb-VS/d)	208,289	208,289	208,289	208,289	208,289	
Total Flow (gpd)	327,774	328,003	328,072	328,172	328,371	
Primary sludge percent of VS Load (%)	25%	31%	33%	36%	41%	
WAS percent of VS Load (%)	14%	17%	18%	20%	23%	
FOG percent of VS Load (%)	2%	2%	2%	2%	2%	
SSO percent of VS Load (%)	59%	50%	47%	43%	35%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	12	12	12	12	12	
Co-Digestion OLR (lbs-VS/d-cf)	0.40	0.40	0.40	0.40	0.40	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	135,655	165,632	174,756	187,790	213,857	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	4.5%	4.5%	4.5%	4.5%	4.5%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	110,317	93,235	88,036	80,609	65,755	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	161,499	155,527	153,710	151,114	145,922	
Total Sludge Effluent (gpd)	327,774	328,003	328,072	328,172	328,371	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	84,529	90,671	92,541	95,212	100,553	
Volatile Solids (Lbs-VS/d)	46,790	52,761	54,579	57,175	62,367	
Total Solids (% TS)	3.1%	3.3%	3.4%	3.5%	3.7%	
Volatile Solids (% VS)	55%	58%	59%	60%	62%	
Dewatered Solids (Lbs-TS/d)	80,302	86,138	87,914	90,451	95,526	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	183	196	200	206	217	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	1,985,700	1,678,223	1,584,643	1,450,957	1,183,585	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	2,896,737	2,787,035	2,753,648	2,705,951	2,610,558	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	144,205	121,875	115,079	105,371	85,954	
SSO Volatile Solids Load (lb-VS/d)	122,574	103,594	97,817	89,565	73,061	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	5,861	4,953	4,677	4,282	3,493	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	39	39	39	39	39	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.45	9.45	9.45	9.45	9.45	
Total Nitrogen (lb-N/d)	8,569	8,279	8,191	8,065	7,813	
Flow to Digeseter (MGD)	0.33	0.33	0.33	0.33	0.33	
Ammonium-N Conc. (mg/L)	3,135	3,027	2,994	2,947	2,853	
Ammonium-N (molar)	0.22	0.22	0.21	0.21	0.20	
Log Ammonia-N	-3.05	-3.07	-3.07	-3.08	-3.09	
Ammonia Concentration (mg-NH_3-N/L)	12.48	12.05	11.92	11.73	11.36	
Ammonia Concentration (mg-NH_3/L)	15.18	14.65	14.50	14.27	13.81	
Ammonia Toxcitiy Check	Toxic	Toxic	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-003
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - All Digesters in Service		

Co-digestion Assessment

Mesophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.18	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	97	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS_d)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Mesophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	5.84	5.84	5.84	5.84	5.84	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	28	23	22	20	18	
Base OLR (lbsVS/d-cf)	0.09	0.11	0.11	0.12	0.14	
Hydraulic Capacity (HC) (gpd)	180,403	134,312	120,284	100,244	60,165	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	153,465	114,256	102,323	85,276	51,181	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	73,218	58,456	53,963	47,544	34,707	*Difference between max OLR (0.18 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	73,218	58,456	53,963	47,544	34,707	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	73,218	58,456	53,963	47,544	34,707	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	73,218	58,456	53,963	47,544	34,707	
SSO Total Solids Load (lb-TS/day)	86,139	68,771	63,486	55,935	40,832	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	86,139	68,771	63,486	55,935	40,832	
SSO (lb-wet/day)	717,824	573,095	529,047	466,121	340,269	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	717,824	573,095	529,047	466,121	340,269	
SSO (wtpd)	359	287	265	233	170	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	359	287	265	233	170	
SSO (gpd)	86,070	68,716	63,435	55,890	40,800	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	86,070	68,716	63,435	55,890	40,800	
Total Solids, Total Solids Load (lb-TS/d)	166,159	166,279	166,315	166,367	166,471	
Total Solids, Volatile Solids Load (lb-VS/d)	140,595	140,595	140,595	140,595	140,595	
Total Flow (gpd)	295,167	323,905	332,651	345,146	370,135	
Primary sludge percent of VS Load (%)	30%	37%	39%	42%	48%	

WAS percent of VS Load (%)	16%	20%	21%	22%	26%	
FOG percent of VS Load (%)	2%	2%	2%	2%	2%	
SSO percent of VS Load (%)	52%	42%	38%	34%	25%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	20	18	18	17	16	
Co-Digestion OLR (lbs-VS/d-cf)	0.18	0.18	0.18	0.18	0.18	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	65,896	52,610	48,566	42,790	31,237	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	106,454	101,835	100,430	98,422	94,405	
Total Sludge Effluent (gpd)	295,167	323,905	332,651	345,146	370,135	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	59,705	64,443	65,885	67,945	72,065	
Volatile Solids (Lbs-VS/d)	34,141	38,759	40,165	42,173	46,190	
Total Solids (% TS)	2.4%	2.4%	2.4%	2.4%	2.3%	
Volatile Solids (% VS)	57%	60%	61%	62%	64%	
Dewatered Solids (Lbs-TS/d)	56,720	61,221	62,591	64,548	68,462	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	129	139	142	147	156	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	1,186,132	946,982	874,197	770,218	562,261	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	1,908,063	1,823,193	1,797,363	1,760,462	1,686,662	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	86,139	68,771	63,486	55,935	40,832	
SSO Volatile Solids Load (lb-VS/d)	73,218	58,456	53,963	47,544	34,707	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	3,501	2,795	2,580	2,273	1,659	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	36	36	36	36	36	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.47	9.47	9.47	9.47	9.47	
Total Nitrogen (lb-N/d)	5,620	5,397	5,328	5,231	5,037	
Flow to Digeseter (MGD)	0.30	0.32	0.33	0.35	0.37	
Ammonium-N Conc. (mg/L)	2,283	1,998	1,921	1,817	1,632	
Ammonium-N (molar)	0.16	0.14	0.14	0.13	0.12	
Log Ammonia-N	-3.21	-3.26	-3.28	-3.31	-3.35	
Ammonia Concentration (mg-NH_3-N/L)	8.71	7.62	7.33	6.93	6.23	
Ammonia Concentration (mg-NH_3/L)	10.60	9.27	8.91	8.43	7.57	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-003
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - All Digesters in Service		

Co-digestion Assessment

Mesophilic Digestion with Digesters 1-6

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.18	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	97	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Mesophilic Digestion with Digesters 1-6 Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	6.70	6.70	6.70	6.70	6.70	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	32	26	25	23	20	
Base OLR (lbsVS/d-cf)	0.08	0.09	0.10	0.10	0.12	
Hydraulic Capacity (HC) (gpd)	237,403	191,312	177,284	157,244	117,165	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	201,954	162,745	150,812	133,764	99,670	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	93,793	79,031	74,538	68,119	55,282	*Difference between max OLR (0.18 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	93,793	79,031	74,538	68,119	55,282	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	93,793	79,031	74,538	68,119	55,282	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	93,793	79,031	74,538	68,119	55,282	
SSO Total Solids Load (lb-TS/day)	110,345	92,977	87,691	80,140	65,038	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	110,345	92,977	87,691	80,140	65,038	
SSO (lb-wet/day)	919,538	774,809	730,761	667,835	541,984	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	919,538	774,809	730,761	667,835	541,984	
SSO (wtpd)	460	387	365	334	271	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	460	387	365	334	271	
SSO (gpd)	110,256	92,903	87,621	80,076	64,986	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	110,256	92,903	87,621	80,076	64,986	
Total Solids, Total Solids Load (lb-TS/d)	190,365	190,484	190,521	190,573	190,676	
Total Solids, Volatile Solids Load (lb-VS/d)	161,170	161,170	161,170	161,170	161,170	
Total Flow (gpd)	319,353	348,091	356,837	369,332	394,321	
Primary sludge percent of VS Load (%)	26%	32%	34%	36%	41%	
WAS percent of VS Load (%)	14%	17%	18%	19%	22%	
FOG percent of VS Load (%)	2%	2%	2%	2%	2%	
SSO percent of VS Load (%)	58%	49%	46%	42%	34%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	21	19	19	18	17	

Co-Digestion OLR (lbs-VS/d-cf)	0.18	0.18	0.18	0.18	0.18	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	84,414	71,127	67,084	61,307	49,754	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	124,972	120,353	118,947	116,939	112,923	
Total Sludge Effluent (gpd)	319,353	348,091	356,837	369,332	394,321	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	65,394	70,132	71,574	73,634	77,754	
Volatile Solids (Lbs-VS/d)	36,198	40,817	42,223	44,231	48,247	
Total Solids (% TS)	2.5%	2.4%	2.4%	2.4%	2.4%	
Volatile Solids (% VS)	55%	58%	59%	60%	62%	
Dewatered Solids (Lbs-TS/d)	62,124	66,625	67,995	69,952	73,866	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	141	151	155	159	168	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	1,519,445	1,280,295	1,207,510	1,103,531	895,574	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	2,241,375	2,156,505	2,130,675	2,093,775	2,019,975	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	110,345	92,977	87,691	80,140	65,038	
SSO Volatile Solids Load (lb-VS/d)	93,793	79,031	74,538	68,119	55,282	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	4,484	3,779	3,564	3,257	2,643	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (If applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	36	36	36	36	36	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.47	9.47	9.47	9.47	9.47	
Total Nitrogen (lb-N/d)	6,604	6,380	6,312	6,215	6,020	
Flow to Digeseter (MGD)	0.32	0.35	0.36	0.37	0.39	
Ammonium-N Conc. (mg/L)	2,480	2,198	2,121	2,018	1,831	
Ammonium-N (molar)	0.18	0.16	0.15	0.14	0.13	
Log Ammonia-N	-3.17	-3.22	-3.24	-3.26	-3.30	
Ammonia Concentration (mg-NH_3-N/L)	9.46	8.39	8.09	7.70	6.99	
Ammonia Concentration (mg-NH_3/L)	11.51	10.20	9.84	9.36	8.50	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

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Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-003
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - All Digesters in Service		

Co-digestion Assessment

15 day Thermophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS_d)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 15 day Thermophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	5.84	5.84	5.84	5.84	5.84	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	28	23	22	20	18	
Base OLR (lbsVS/d-cf)	0.09	0.11	0.11	0.12	0.14	
Hydraulic Capacity (HC) (gpd)	180,403	134,312	120,284	100,244	60,165	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	153,465	114,256	102,323	85,276	51,181	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	206,002	191,240	186,747	180,328	167,492	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Hydraulic	Hydraulic	Hydraulic	Hydraulic	Hydraulic	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	153,465	114,256	102,323	85,276	51,181	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	153,465	114,256	102,323	85,276	51,181	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	153,465	114,256	102,323	85,276	51,181	
SSO Total Solids Load (lb-TS/day)	180,547	134,419	120,380	100,324	60,213	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	180,547	134,419	120,380	100,324	60,213	
SSO (lb-wet/day)	1,504,561	1,120,159	1,003,168	836,037	501,774	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,504,561	1,120,159	1,003,168	836,037	501,774	
SSO (wtpd)	752	560	502	418	251	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	752	560	502	418	251	
SSO (gpd)	180,403	134,312	120,284	100,244	60,165	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	180,403	134,312	120,284	100,244	60,165	
Total Solids, Total Solids Load (lb-TS/d)	260,568	231,926	223,209	210,757	185,851	
Total Solids, Volatile Solids Load (lb-VS/d)	220,842	196,396	188,955	178,326	157,068	
Total Flow (gpd)	389,500	389,500	389,500	389,500	389,500	
Primary sludge percent of VS Load (%)	19%	26%	29%	33%	43%	

WAS percent of VS Load (%)	10%	14%	15%	18%	23%	
FOG percent of VS Load (%)	1%	2%	2%	2%	2%	
SSO percent of VS Load (%)	69%	58%	54%	48%	33%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	15	15	15	15	15	
Co-Digestion OLR (lbs-VS/d-cf)	0.28	0.25	0.24	0.23	0.20	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Productior

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	138,119	102,831	92,091	76,748	46,063	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	178,677	152,056	143,954	132,380	109,232	
Total Sludge Effluent (gpd)	389,500	389,500	389,500	389,500	389,500	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	81,891	79,870	79,255	78,377	76,620	
Volatile Solids (Lbs-VS/d)	42,166	44,340	45,001	45,946	47,837	
Total Solids (% TS)	2.5%	2.5%	2.4%	2.4%	2.4%	
Volatile Solids (% VS)	51%	56%	57%	59%	62%	
Dewatered Solids (Lbs-TS/d)	77,797	75,877	75,293	74,458	72,789	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	177	172	171	169	165	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	2,486,137	1,850,952	1,657,634	1,381,467	829,132	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	3,208,067	2,727,162	2,580,800	2,371,711	1,953,534	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	180,547	134,419	120,380	100,324	60,213	
SSO Volatile Solids Load (lb-VS/d)	153,465	114,256	102,323	85,276	51,181	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	7,338	5,463	4,892	4,077	2,447	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (If applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	9,457	8,065	7,641	7,035	5,824	
Flow to Digeseter (MGD)	0.39	0.39	0.39	0.39	0.39	
Ammonium-N Conc. (mg/L)	2,911	2,483	2,352	2,166	1,793	
Ammonium-N (molar)	0.21	0.18	0.17	0.15	0.13	
Log Ammonia-N	-2.85	-2.92	-2.95	-2.98	-3.07	
Ammonia Concentration (mg-NH_3-N/L)	19.56	16.68	15.80	14.55	12.05	
Ammonia Concentration (mg-NH_3/L)	23.79	20.29	19.22	17.70	14.65	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Brown AND Caldwell

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-003
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - All Digesters in Service		

Co-digestion Assessment

15 day Thermophilic Digestion with All digesters in service

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 15 day Thermophilic Digestion with All digesters in service Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	6.70	6.70	6.70	6.70	6.70	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	32	26	25	23	20	
Base OLR (lbsVS/d-cf)	0.08	0.09	0.10	0.10	0.12	
Hydraulic Capacity (HC) (gpd)	237,403	191,312	177,284	157,244	117,165	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	201,954	162,745	150,812	133,764	99,670	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	246,009	231,246	226,754	220,335	207,498	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Hydraulic	Hydraulic	Hydraulic	Hydraulic	Hydraulic	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	201,954	162,745	150,812	133,764	99,670	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	201,954	162,745	150,812	133,764	99,670	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	201,954	162,745	150,812	133,764	99,670	
SSO Total Solids Load (lb-TS/day)	237,593	191,465	177,426	157,370	117,259	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	237,593	191,465	177,426	157,370	117,259	
SSO (lb-wet/day)	1,979,941	1,595,539	1,478,548	1,311,417	977,154	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,979,941	1,595,539	1,478,548	1,311,417	977,154	
SSO (wtpd)	990	798	739	656	489	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	990	798	739	656	489	
SSO (gpd)	237,403	191,312	177,284	157,244	117,165	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	237,403	191,312	177,284	157,244	117,165	
Total Solids, Total Solids Load (lb-TS/d)	317,613	288,972	280,255	267,802	242,897	
Total Solids, Volatile Solids Load (lb-VS/d)	269,331	244,884	237,444	226,815	205,557	
Total Flow (gpd)	446,500	446,500	446,500	446,500	446,500	
Primary sludge percent of VS Load (%)	16%	21%	23%	26%	33%	
WAS percent of VS Load (%)	8%	11%	12%	14%	17%	
FOG percent of VS Load (%)	1%	1%	1%	1%	2%	
SSO percent of VS Load (%)	75%	66%	64%	59%	48%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	15	15	15	15	15	

Co-Digestion OLR (lbs-VS/d-cf)	0.30	0.27	0.27	0.25	0.23	
Process Check	OK	OK	OK	OK	OK	
Table X-X: Existing Mesophilic Solids and Biogas Production						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	
Table X-X: Mesophilic Co-digestion Solids and Biogas Production						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	181,759	146,471	135,731	120,388	89,703	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	222,316	195,696	187,594	176,020	152,871	
Total Sludge Effluent (gpd)	446,500	446,500	446,500	446,500	446,500	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	95,297	93,276	92,661	91,783	90,025	
Volatile Solids (Lbs-VS/d)	47,014	49,188	49,850	50,795	52,686	
Total Solids (% TS)	2.6%	2.5%	2.5%	2.5%	2.4%	
Volatile Solids (% VS)	49%	53%	54%	55%	59%	
Dewatered Solids (Lbs-TS/d)	90,532	88,612	88,028	87,193	85,524	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	206	201	200	198	194	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	3,271,655	2,636,469	2,443,152	2,166,985	1,614,650	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	3,993,585	3,512,680	3,366,318	3,157,229	2,739,051	
Table X-X: Nutrient Loading - Ammonia-N Estimates						
HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	237,593	191,465	177,426	157,370	117,259	
SSO Volatile Solids Load (lb-VS/d)	201,954	162,745	150,812	133,764	99,670	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	9,656	7,781	7,211	6,396	4,765	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	11,776	10,383	9,959	9,354	8,143	
Flow to Digeseter (MGD)	0.45	0.45	0.45	0.45	0.45	
Ammonium-N Conc. (mg/L)	3,162	2,788	2,674	2,512	2,187	
Ammonium-N (molar)	0.23	0.20	0.19	0.18	0.16	
Log Ammonia-N	-2.82	-2.87	-2.89	-2.92	-2.98	
Ammonia Concentration (mg-NH_3-N/L)	21.25	18.73	17.97	16.88	14.69	
Ammonia Concentration (mg-NH_3/L)	25.84	22.79	21.86	20.53	17.87	
Ammonia Toxcitiy Check	Toxic	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-003
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - All Digesters in Service		

Co-digestion Assessment

10 day Thermophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	10	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effiency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS$_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

#REF!

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	5.84	5.84	5.84	5.84	5.84	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	28	23	22	20	18	
Base OLR (lbsVS/d-cf)	0.09	0.11	0.11	0.12	0.14	
Hydraulic Capacity (HC) (gpd)	375,153	329,062	315,034	294,994	254,915	*Assumes the minimum allowable HRT 10 days*
HC as Equivalent VS Load (lb-VS/day)	319,135	279,926	267,993	250,946	216,851	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	206,002	191,240	186,747	180,328	167,492	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	206,002	191,240	186,747	180,328	167,492	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	206,002	191,240	186,747	180,328	167,492	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	206,002	191,240	186,747	180,328	167,492	
SSO Total Solids Load (lb-TS/day)	242,355	224,988	219,702	212,151	197,049	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	242,355	224,988	219,702	212,151	197,049	
SSO (lb-wet/day)	2,019,629	1,874,900	1,830,851	1,767,926	1,642,074	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	2,019,629	1,874,900	1,830,851	1,767,926	1,642,074	
SSO (wtpd)	1,010	937	915	884	821	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	1,010	937	915	884	821	
SSO (gpd)	242,162	224,808	219,527	211,981	196,891	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	242,162	224,808	219,527	211,981	196,891	
Total Solids, Total Solids Load (lb-TS/d)	322,376	322,495	322,532	322,583	322,687	
Total Solids, Volatile Solids Load (lb-VS/d)	273,379	273,379	273,379	273,379	273,379	
Total Flow (gpd)	451,259	479,996	488,743	501,237	526,227	
Primary sludge percent of VS Load (%)	15%	19%	20%	21%	24%	

WAS percent of VS Load (%)	8%	10%	11%	11%	13%	
FOG percent of VS Load (%)	1%	1%	1%	1%	1%	
SSO percent of VS Load (%)	75%	70%	68%	66%	61%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	13	12	12	12	11	
Co-Digestion OLR (lbs-VS/d-cf)	0.35	0.35	0.35	0.35	0.35	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	185,402	172,116	168,072	162,296	150,742	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	225,960	221,341	219,935	217,927	213,911	
Total Sludge Effluent (gpd)	451,259	479,996	488,743	501,237	526,227	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	96,416	101,154	102,596	104,656	108,776	
Volatile Solids (Lbs-VS/d)	47,419	52,038	53,444	55,452	59,468	
Total Solids (% TS)	2.6%	2.5%	2.5%	2.5%	2.5%	
Volatile Solids (% VS)	49%	51%	52%	53%	55%	
Dewatered Solids (Lbs-TS/d)	91,595	96,096	97,466	99,423	103,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	208	218	222	226	235	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	3,337,235	3,098,084	3,025,299	2,921,320	2,713,363	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	4,059,165	3,974,295	3,948,465	3,911,565	3,837,765	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	242,355	224,988	219,702	212,151	197,049	
SSO Volatile Solids Load (lb-VS/d)	206,002	191,240	186,747	180,328	167,492	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	9,849	9,144	8,929	8,622	8,008	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	11,969	11,745	11,677	11,580	11,385	
Flow to Digeseter (MGD)	0.45	0.48	0.49	0.50	0.53	
Ammonium-N Conc. (mg/L)	3,180	2,934	2,865	2,770	2,594	
Ammonium-N (molar)	0.23	0.21	0.20	0.20	0.19	
Log Ammonia-N	-2.82	-2.85	-2.86	-2.88	-2.91	
Ammonia Concentration (mg-NH_3-N/L)	21.37	19.71	19.25	18.61	17.43	
Ammonia Concentration (mg-NH_3/L)	25.99	23.98	23.41	22.64	21.20	
Ammonia Toxcitiy Check	Toxic	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-003
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - All Digesters in Service		

Co-digestion Assessment

10 day Thermophilic Digestion with All digesters in service

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	10	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 10 day Thermophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	6.70	6.70	6.70	6.70	6.70	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	209,097	255,188	269,216	289,256	329,335	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	32	26	25	23	20	
Base OLR (lbsVS/d-cf)	0.08	0.09	0.10	0.10	0.12	
Hydraulic Capacity (HC) (gpd)	460,653	414,562	400,534	380,494	340,415	*Assumes the minimum allowable HRT 10 days*
HC as Equivalent VS Load (lb-VS/day)	391,868	352,659	340,726	323,679	289,584	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	246,009	231,246	226,754	220,335	207,498	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	246,009	231,246	226,754	220,335	207,498	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	246,009	231,246	226,754	220,335	207,498	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	246,009	231,246	226,754	220,335	207,498	
SSO Total Solids Load (lb-TS/day)	289,422	272,055	266,769	259,218	244,116	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	289,422	272,055	266,769	259,218	244,116	
SSO (lb-wet/day)	2,411,851	2,267,122	2,223,074	2,160,148	2,034,296	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	2,411,851	2,267,122	2,223,074	2,160,148	2,034,296	
SSO (wtpd)	1,206	1,134	1,112	1,080	1,017	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	1,206	1,134	1,112	1,080	1,017	
SSO (gpd)	289,191	271,837	266,556	259,011	243,920	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	289,191	271,837	266,556	259,011	243,920	
Total Solids, Total Solids Load (lb-TS/d)	369,443	369,562	369,598	369,650	369,754	
Total Solids, Volatile Solids Load (lb-VS/d)	313,386	313,386	313,386	313,386	313,386	
Total Flow (gpd)	498,288	527,025	535,772	548,266	573,256	
Primary sludge percent of VS Load (%)	13%	16%	17%	19%	21%	
WAS percent of VS Load (%)	7%	9%	9%	10%	11%	
FOG percent of VS Load (%)	1%	1%	1%	1%	1%	
SSO percent of VS Load (%)	79%	74%	72%	70%	66%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	13	13	13	12	12	

Co-Digestion OLR (lbs-VS/d-cf)	0.35	0.35	0.35	0.35	0.35	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	209,097	255,188	269,216	289,256	329,335	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	221,408	208,122	204,078	198,302	186,748	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	261,966	257,347	255,941	253,933	249,917	
Total Sludge Effluent (gpd)	498,288	527,025	535,772	548,266	573,256	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	107,477	112,215	113,657	115,717	119,837	
Volatile Solids (Lbs-VS/d)	51,420	56,039	57,444	59,452	63,469	
Total Solids (% TS)	2.6%	2.6%	2.5%	2.5%	2.5%	
Volatile Solids (% VS)	48%	50%	51%	51%	53%	
Dewatered Solids (Lbs-TS/d)	102,103	106,604	107,974	109,931	113,845	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	232	242	245	250	259	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	3,985,343	3,746,192	3,673,407	3,569,429	3,361,471	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	4,707,273	4,622,403	4,596,573	4,559,673	4,485,873	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	289,422	272,055	266,769	259,218	244,116	
SSO Volatile Solids Load (lb-VS/d)	246,009	231,246	226,754	220,335	207,498	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	11,762	11,056	10,842	10,535	9,921	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (If applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	13,882	13,658	13,590	13,493	13,298	
Flow to Digeseter (MGD)	0.50	0.53	0.54	0.55	0.57	
Ammonium-N Conc. (mg/L)	3,340	3,107	3,041	2,951	2,781	
Ammonium-N (molar)	0.24	0.22	0.22	0.21	0.20	
Log Ammonia-N	-2.80	-2.83	-2.84	-2.85	-2.87	
Ammonia Concentration (mg-NH_3-N/L)	22.45	20.88	20.44	19.83	18.69	
Ammonia Concentration (mg-NH_3/L)	27.30	25.39	24.86	24.11	22.73	
Ammonia Toxcitiy Check	Toxic	Toxic	Toxic	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-003
Project			Subject		
Encina Biosolids, Energy, and Emissions			Current Year - All Digesters in Service		

Co-digestion Assessment

Thermal Hydrolysis with Mesophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	12	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.4	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1	Percent Solids Content of Digester Feed	9%	Assumed	Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	102	Assumed	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	140,397	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	60,000	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS$_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO		Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Thermal Hydrolysis with Mesophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	5.84	5.84	5.84	5.84	5.84	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	80,020	97,507	102,829	110,432	125,638	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	67,377	82,139	86,632	93,051	105,887	
Primary sludge percent of VS Load (%)	62%	63%	63%	63%	63%	
WAS percent of VS Load (%)	33%	34%	34%	34%	34%	
FOG percent of VS Load (%)	5%	4%	4%	3%	3%	
Total Digester Feed Flow (gpd)	106,609	129,906	136,996	147,125	167,384	
Total Percent Solids Load (%)	9.0%	9.0%	9.0%	9.0%	9.0%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.3%	84.3%	
Base HRT (days)	55	45	43	40	35	
Base OLR (lbsVS/d-cf)	0.09	0.11	0.11	0.12	0.14	
Hydraulic Capacity (HC) (gpd)	380,266	356,969	349,879	339,750	319,491	*Assumes the minimum allowable HRT 12 days*
HC as Equivalent VS Load (lb-VS/day)	323,485	303,667	297,635	289,018	271,785	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	245,056	230,294	225,801	219,383	206,546	*Difference between max OLR (0.4 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	245,056	230,294	225,801	219,383	206,546	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	245,056	230,294	225,801	219,383	206,546	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	245,056	230,294	225,801	219,383	206,546	
SSO Total Solids Load (lb-TS/day)	288,302	270,934	265,648	258,097	242,995	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	288,302	270,934	265,648	258,097	242,995	
SSO (lb-wet/day)	2,402,513	2,257,783	2,213,735	2,150,809	2,024,958	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	2,402,513	2,257,783	2,213,735	2,150,809	2,024,958	
SSO (wtpd)	1,201	1,129	1,107	1,075	1,012	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	1,201	1,129	1,107	1,075	1,012	
SSO Digester Feed (gpd)	384,095	360,957	353,915	343,854	323,734	*Assume 9% TS*
HSOW No. 2 (gpd)	0	0	0	0	0	*Assume 9% TS*
SSO Digester Feed(gpd)	384,095	360,957	353,915	343,854	323,734	*Assume 9% TS*
SSO As Received(gpd)	288,071	270,717	265,436	257,891	242,801	*Assume 12% TS*
HSOW No. 2 (gpd)	0	0	0	0	0	*Assume 12% TS*
SSO As Received (gpd)	288,071	270,717	265,436	257,891	242,801	*Assume 12% TS*
Total Solids, Total Solids Load (lb-TS/d)	368,322	368,441	368,478	368,529	368,633	

Total Solids, Volatile Solids Load (lb-VS/d)	312,433	312,433	312,433	312,433	312,433	
Total Flow (gpd)	490,703	490,862	490,911	490,980	491,118	
Primary sludge percent of VS Load (%)	13%	16%	17%	19%	21%	
WAS percent of VS Load (%)	7%	9%	9%	10%	11%	
FOG percent of VS Load (%)	1%	1%	1%	1%	1%	
SSO percent of VS Load (%)	78%	74%	72%	70%	66%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	12	12	12	12	12	
Co-Digestion OLR (lbs-VS/d-cf)	0.40	0.40	0.40	0.40	0.40	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	40,558	49,225	51,863	55,632	63,169	
Total Sludge Effluent (gpd)	106,609	129,906	136,996	147,125	167,384	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	39,463	48,282	50,966	54,801	62,470	
Volatile Solids Effluent (Lbs-VS/d)	26,819	32,914	34,769	37,419	42,719	
Total Solids (% TS)	4.4%	4.5%	4.5%	4.5%	4.5%	
Volatile Solids (% VS)	68%	68%	68%	68%	68%	
Dewatered Solids (Lbs-TS/d)	37,489	45,868	48,418	52,061	59,346	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	85	104	110	118	135	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	721,930	876,211	923,166	990,244	1,124,401	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	27,148	33,392	35,293	38,007	43,437	
WAS Volatile Solids Destroyed (lb-VSd/day)	10,536	12,960	13,697	14,751	16,858	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	220,551	207,265	203,221	197,444	185,891	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	261,109	256,490	255,084	253,076	249,060	
Total Sludge Effluent (gpd)	490,703	490,862	490,911	490,980	491,118	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	107,213	111,951	113,393	115,453	119,573	
Volatile Solids (Lbs-VS/d)	51,325	55,943	57,349	59,357	63,373	
Total Solids (% TS)	2.6%	2.7%	2.8%	2.8%	2.9%	
Volatile Solids (% VS)	48%	50%	51%	51%	53%	
Dewatered Solids (Lbs-TS/d)	101,853	106,354	107,724	109,681	113,595	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	231	242	245	249	258	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	483,237	594,382	628,208	676,532	773,179	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	187,548	230,684	243,813	262,568	300,077	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	3,969,912	3,730,761	3,657,976	3,553,998	3,346,040	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	4,691,842	4,606,972	4,581,142	4,544,242	4,470,442	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	288,302	270,934	265,648	258,097	242,995	
SSO Volatile Solids Load (lb-VS/d)	245,056	230,294	225,801	219,383	206,546	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	11,717	11,011	10,796	10,489	9,875	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	48,007	59,049	62,410	67,210	76,812	
Primary Sludge Volatile Solids Load (lb-VS/d)	41,766	51,373	54,296	58,473	66,826	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,545	1,900	2,008	2,163	2,471	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	28,022	34,468	36,429	39,231	44,836	
TWAS Volatile Solids Load (lb-VS/d)	22,418	27,574	29,143	31,385	35,869	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	551	678	717	772	882	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	39	39	39	39	39	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.45	9.45	9.45	9.45	9.45	
Total Nitrogen (lb-N/d)	13,836	13,613	13,544	13,447	13,253	
Flow to Digeseter (MGD)	0.49	0.49	0.49	0.49	0.49	
Ammonium-N Conc. (mg/L)	3,381	3,325	3,308	3,284	3,236	
Ammonium-N (molar)	0.24	0.24	0.24	0.23	0.23	
Log Ammonia-N	-3.02	-3.02	-3.03	-3.03	-3.04	
Ammonia Concentration (mg-NH_3-N/L)	13.46	13.24	13.17	13.07	12.88	
Ammonia Concentration (mg-NH_3/L)	16.37	16.10	16.02	15.90	15.67	
Ammonia Toxcitiy Check	Toxic	Toxic	Toxic	Toxic	Toxic	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-004
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - All Digesters in Service		

Co-digestion Assessment

Mesophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.18	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	97	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Mesophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	5.84	5.84	5.84	5.84	5.84	*Service condition assumes largest digester is out of service with the active volume of each digeser reduc*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	22	18	17	16	14	
Base OLR (lbsVS/d-cf)	0.11	0.13	0.14	0.15	0.17	
Hydraulic Capacity (HC) (gpd)	123,692	64,557	46,559	20,848	-30,573	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	105,222	54,917	39,607	17,735	-26,008	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	54,880	35,900	30,124	21,871	5,367	*Difference between max OLR (0.18 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Hydraulic	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	54,880	35,900	30,124	17,735	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	54,880	35,900	30,124	17,735	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	54,880	35,900	30,124	17,735	0	
SSO Total Solids Load (lb-TS/day)	64,565	42,235	35,440	20,865	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	64,565	42,235	35,440	20,865	0	
SSO (lb-wet/day)	538,042	351,962	295,330	173,875	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	538,042	351,962	295,330	173,875	0	
SSO (wtpd)	269	176	148	87	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	269	176	148	87	0	
SSO (gpd)	64,513	42,202	35,411	20,848	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	64,513	42,202	35,411	20,848	0	
Total Solids, Total Solids Load (lb-TS/d)	166,387	166,559	166,611	161,820	160,521	
Total Solids, Volatile Solids Load (lb-VS/d)	140,595	140,595	140,595	136,459	135,228	
Total Flow (gpd)	330,322	367,145	378,352	389,500	420,073	
Primary sludge percent of VS Load (%)	38%	46%	49%	54%	63%	
WAS percent of VS Load (%)	21%	26%	27%	30%	35%	
FOG percent of VS Load (%)	2%	2%	2%	2%	2%	

SSO percent of VS Load (%)	39%	26%	21%	13%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	18	16	15	15	14	
Co-Digestion OLR (lbs-VS/d-cf)	0.18	0.18	0.18	0.17	0.17	
Process Check	OK	OK	OK	OK	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	49,392	32,310	27,111	15,962	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	100,574	94,603	92,786	86,467	80,167	
Total Sludge Effluent (gpd)	330,322	367,145	378,352	389,500	420,073	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	65,813	71,956	73,826	75,353	80,354	
Volatile Solids (Lbs-VS/d)	40,021	45,992	47,809	49,992	55,061	
Total Solids (% TS)	2.4%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	61%	64%	65%	66%	69%	
Dewatered Solids (Lbs-TS/d)	62,523	68,358	70,134	71,585	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	142	155	159	163	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	889,060	581,583	488,003	287,311	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	1,800,097	1,690,395	1,657,007	1,542,304	1,426,972	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	64,565	42,235	35,440	20,865	0	
SSO Volatile Solids Load (lb-VS/d)	54,880	35,900	30,124	17,735	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.000	
SSO Ammonium-N Load (lb-N/day)	2,624	1,716	1,440	848	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (If applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	36	36	36	36	36	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.47	9.47	9.47	9.47	9.47	
Total Nitrogen (lb-N/d)	5,333	5,043	4,954	4,631	4,320	
Flow to Digeseter (MGD)	0.33	0.37	0.38	0.39	0.42	
Ammonium-N Conc. (mg/L)	1,936	1,647	1,570	1,425	1,233	
Ammonium-N (molar)	0.14	0.12	0.11	0.10	0.09	
Log Ammonia-N	-3.28	-3.35	-3.37	-3.41	-3.47	
Ammonia Concentration (mg-NH_3-N/L)	7.39	6.28	5.99	5.44	4.70	
Ammonia Concentration (mg-NH_3/L)	8.98	7.64	7.29	6.62	5.72	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

ed to account for process inefficiencies.

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-004
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - All Digesters in Service		

Co-digestion Assessment

Mesophilic Digestion with Digesters 1-6

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.18	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	97	1	Peak 14 day	1.3	2
Digester Effiency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Mesophilic Digestion with Digesters 1-6 Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	6.70	6.70	6.70	6.70	6.70	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	25	21	20	18	16	
Base OLR (lbsVS/d-cf)	0.10	0.12	0.12	0.13	0.15	
Hydraulic Capacity (HC) (gpd)	180,692	121,557	103,559	77,848	26,427	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	153,711	103,406	88,096	66,224	22,481	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	75,455	56,475	50,698	42,446	25,942	*Difference between max OLR (0.18 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Hydraulic	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	75,455	56,475	50,698	42,446	22,481	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	75,455	56,475	50,698	42,446	22,481	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	75,455	56,475	50,698	42,446	22,481	
SSO Total Solids Load (lb-TS/day)	88,771	66,441	59,645	49,937	26,448	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	88,771	66,441	59,645	49,937	26,448	
SSO (lb-wet/day)	739,756	553,677	497,044	416,140	220,398	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	739,756	553,677	497,044	416,140	220,398	
SSO (wtpd)	370	277	249	208	110	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	370	277	249	208	110	
SSO (gpd)	88,700	66,388	59,598	49,897	26,427	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	88,700	66,388	59,598	49,897	26,427	
Total Solids, Total Solids Load (lb-TS/d)	190,593	190,765	190,817	190,892	186,969	
Total Solids, Volatile Solids Load (lb-VS/d)	161,170	161,170	161,170	161,170	157,709	
Total Flow (gpd)	354,508	391,331	402,538	418,549	446,500	
Primary sludge percent of VS Load (%)	33%	40%	43%	46%	54%	
WAS percent of VS Load (%)	18%	23%	24%	26%	30%	
FOG percent of VS Load (%)	2%	2%	2%	2%	2%	
SSO percent of VS Load (%)	47%	35%	31%	26%	14%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	19	17	17	16	15	

Co-Digestion OLR (lbs-VS/d-cf)	0.18	0.18	0.18	0.18	0.18	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	67,910	50,828	45,629	38,202	20,233	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	119,091	113,120	111,303	108,707	100,400	
Total Sludge Effluent (gpd)	354,508	391,331	402,538	418,549	446,500	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	71,502	77,644	79,514	82,185	86,569	
Volatile Solids (Lbs-VS/d)	42,078	48,049	49,867	52,463	57,309	
Total Solids (% TS)	2.4%	2.4%	2.4%	2.4%	2.3%	
Volatile Solids (% VS)	59%	62%	63%	64%	66%	
Dewatered Solids (Lbs-TS/d)	67,926	73,762	75,538	78,076	82,241	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	154	168	172	177	187	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	1,222,373	914,895	821,315	687,630	364,186	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	2,133,410	2,023,708	1,990,320	1,942,623	1,791,158	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	88,771	66,441	59,645	49,937	26,448	
SSO Volatile Solids Load (lb-VS/d)	75,455	56,475	50,698	42,446	22,481	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	3,608	2,700	2,424	2,029	1,075	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (If applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	36	36	36	36	36	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.47	9.47	9.47	9.47	9.47	
Total Nitrogen (lb-N/d)	6,316	6,026	5,938	5,812	5,394	
Flow to Digeseter (MGD)	0.35	0.39	0.40	0.42	0.45	
Ammonium-N Conc. (mg/L)	2,136	1,846	1,769	1,665	1,449	
Ammonium-N (molar)	0.15	0.13	0.13	0.12	0.10	
Log Ammonia-N	-3.24	-3.30	-3.32	-3.34	-3.40	
Ammonia Concentration (mg-NH_3-N/L)	8.15	7.05	6.75	6.35	5.53	
Ammonia Concentration (mg-NH_3/L)	9.91	8.57	8.21	7.73	6.72	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Brown AND Caldwell

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-004
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - All Digesters in Service		

Co-digestion Assessment

15 day Thermophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 15 day Thermophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	5.84	5.84	5.84	5.84	5.84	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	22	18	17	16	14	
Base OLR (lbsVS/d-cf)	0.11	0.13	0.14	0.15	0.17	
Hydraulic Capacity (HC) (gpd)	123,692	64,557	46,559	20,848	-30,573	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	105,222	54,917	39,607	17,735	-26,008	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	187,664	168,684	162,908	154,655	138,151	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Hydraulic	Hydraulic	Hydraulic	Hydraulic	No Capacity	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	105,222	54,917	39,607	17,735	0	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	105,222	54,917	39,607	17,735	0	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	105,222	54,917	39,607	17,735	0	
SSO Total Solids Load (lb-TS/day)	123,791	64,608	46,596	20,865	0	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	123,791	64,608	46,596	20,865	0	
SSO (lb-wet/day)	1,031,588	538,403	388,303	173,875	0	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,031,588	538,403	388,303	173,875	0	
SSO (wtpd)	516	269	194	87	0	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	516	269	194	87	0	
SSO (gpd)	123,692	64,557	46,559	20,848	0	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	123,692	64,557	46,559	20,848	0	
Total Solids, Total Solids Load (lb-TS/d)	225,613	188,932	177,768	161,820	160,521	
Total Solids, Volatile Solids Load (lb-VS/d)	190,937	159,612	150,078	136,459	135,228	
Total Flow (gpd)	389,500	389,500	389,500	389,500	420,073	
Primary sludge percent of VS Load (%)	28%	41%	46%	54%	63%	

WAS percent of VS Load (%)	16%	23%	26%	30%	35%	
FOG percent of VS Load (%)	2%	2%	2%	2%	2%	
SSO percent of VS Load (%)	55%	34%	26%	13%	0%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	15	15	15	15	14	
Co-Digestion OLR (lbs-VS/d-cf)	0.24	0.20	0.19	0.17	0.17	
Process Check	OK	OK	OK	OK	No Capacity	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	94,700	49,425	35,646	15,962	0	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	145,882	111,718	101,321	86,467	80,167	
Total Sludge Effluent (gpd)	389,500	389,500	389,500	389,500	420,073	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	79,731	77,214	76,447	75,353	80,354	
Volatile Solids (Lbs-VS/d)	45,055	47,894	48,758	49,992	55,061	
Total Solids (% TS)	2.5%	2.4%	2.4%	2.3%	2.3%	
Volatile Solids (% VS)	57%	62%	64%	66%	69%	
Dewatered Solids (Lbs-TS/d)	75,745	73,353	72,625	71,585	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	172	167	165	163	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	1,704,596	889,657	641,632	287,311	0	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	2,615,633	1,998,469	1,810,637	1,542,304	1,426,972	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	123,791	64,608	46,596	20,865	0	
SSO Volatile Solids Load (lb-VS/d)	105,222	54,917	39,607	17,735	0	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.000	
SSO Ammonium-N Load (lb-N/day)	5,031	2,626	1,894	848	0	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	7,740	5,952	5,408	4,631	4,320	
Flow to Digeseter (MGD)	0.39	0.39	0.39	0.39	0.42	
Ammonium-N Conc. (mg/L)	2,383	1,832	1,665	1,425	1,233	
Ammonium-N (molar)	0.17	0.13	0.12	0.10	0.09	
Log Ammonia-N	-2.94	-3.06	-3.10	-3.17	-3.23	
Ammonia Concentration (mg-NH_3-N/L)	16.01	12.31	11.19	9.58	8.28	
Ammonia Concentration (mg-NH_3/L)	19.47	14.97	13.60	11.65	10.08	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-004
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - All Digesters in Service		

Co-digestion Assessment

15 day Thermophilic Digestion with All digesters in service

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	15	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effiency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS_d)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 15 day Thermophilic Digestion with All digesters in service Feed Assessment						
	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	6.70	6.70	6.70	6.70	6.70	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	25	21	20	18	16	
Base OLR (lbsVS/d-cf)	0.10	0.12	0.12	0.13	0.15	
Hydraulic Capacity (HC) (gpd)	180,692	121,557	103,559	77,848	26,427	*Assumes the minimum allowable HRT 15 days*
HC as Equivalent VS Load (lb-VS/day)	153,711	103,406	88,096	66,224	22,481	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	227,671	208,691	202,914	194,662	178,158	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Hydraulic	Hydraulic	Hydraulic	Hydraulic	Hydraulic	

Table X-X: Mesophilic Co-digestion Feed Assessment						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	153,711	103,406	88,096	66,224	22,481	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	153,711	103,406	88,096	66,224	22,481	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	153,711	103,406	88,096	66,224	22,481	
SSO Total Solids Load (lb-TS/day)	180,836	121,654	103,642	77,911	26,448	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	180,836	121,654	103,642	77,911	26,448	
SSO (lb-wet/day)	1,506,968	1,013,783	863,683	649,255	220,398	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,506,968	1,013,783	863,683	649,255	220,398	
SSO (wtpd)	753	507	432	325	110	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	753	507	432	325	110	
SSO (gpd)	180,692	121,557	103,559	77,848	26,427	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	180,692	121,557	103,559	77,848	26,427	
Total Solids, Total Solids Load (lb-TS/d)	282,658	245,978	234,814	218,865	186,969	
Total Solids, Volatile Solids Load (lb-VS/d)	239,425	208,101	198,567	184,947	157,709	
Total Flow (gpd)	446,500	446,500	446,500	446,500	446,500	
Primary sludge percent of VS Load (%)	22%	31%	35%	40%	54%	
WAS percent of VS Load (%)	12%	18%	19%	22%	30%	
FOG percent of VS Load (%)	1%	2%	2%	2%	2%	
SSO percent of VS Load (%)	64%	50%	44%	36%	14%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	15	15	15	15	15	

Co-Digestion OLR (lbs-VS/d-cf)	0.27	0.23	0.22	0.21	0.18	
Process Check	OK	OK	OK	OK	OK	
Table X-X: Existing Mesophilic Solids and Biogas Production						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	
Table X-X: Mesophilic Co-digestion Solids and Biogas Production						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	138,340	93,065	79,286	59,602	20,233	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	189,522	155,358	144,961	130,107	100,400	
Total Sludge Effluent (gpd)	446,500	446,500	446,500	446,500	446,500	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	93,137	90,619	89,853	88,759	86,569	
Volatile Solids (Lbs-VS/d)	49,904	52,743	53,606	54,841	57,309	
Total Solids (% TS)	2.5%	2.4%	2.4%	2.4%	2.3%	
Volatile Solids (% VS)	54%	58%	60%	62%	66%	
Dewatered Solids (Lbs-TS/d)	88,480	86,088	85,361	84,321	82,241	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	201	196	194	192	187	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	2,490,114	1,675,175	1,427,150	1,072,828	364,186	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	3,401,151	2,783,987	2,596,155	2,327,822	1,791,158	
Table X-X: Nutrient Loading - Ammonia-N Estimates						
HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	180,836	121,654	103,642	77,911	26,448	
SSO Volatile Solids Load (lb-VS/d)	153,711	103,406	88,096	66,224	22,481	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	7,349	4,944	4,212	3,166	1,075	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (If applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	10,058	8,270	7,726	6,949	5,394	
Flow to Digeseter (MGD)	0.45	0.45	0.45	0.45	0.45	
Ammonium-N Conc. (mg/L)	2,701	2,221	2,075	1,866	1,449	
Ammonium-N (molar)	0.19	0.16	0.15	0.13	0.10	
Log Ammonia-N	-2.89	-2.97	-3.00	-3.05	-3.16	
Ammonia Concentration (mg-NH_3-N/L)	18.15	14.92	13.94	12.54	9.73	
Ammonia Concentration (mg-NH_3/L)	22.07	18.15	16.96	15.25	11.84	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-004
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - All Digesters in Service		

Co-digestion Assessment

10 day Thermophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	10	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 10 day Thermophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	5.84	5.84	5.84	5.84	5.84	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	22	18	17	16	14	
Base OLR (lbsVS/d-cf)	0.11	0.13	0.14	0.15	0.17	
Hydraulic Capacity (HC) (gpd)	318,442	259,307	241,309	215,598	164,177	*Assumes the minimum allowable HRT 10 days*
HC as Equivalent VS Load (lb-VS/day)	270,892	220,587	205,277	183,405	139,662	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	187,664	168,684	162,908	154,655	138,151	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	187,664	168,684	162,908	154,655	138,151	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	187,664	168,684	162,908	154,655	138,151	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	187,664	168,684	162,908	154,655	138,151	
SSO Total Solids Load (lb-TS/day)	220,782	198,452	191,656	181,948	162,531	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	220,782	198,452	191,656	181,948	162,531	
SSO (lb-wet/day)	1,839,846	1,653,767	1,597,134	1,516,230	1,354,422	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	1,839,846	1,653,767	1,597,134	1,516,230	1,354,422	
SSO (wtpd)	920	827	799	758	677	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	920	827	799	758	677	
SSO (gpd)	220,605	198,293	191,503	181,802	162,401	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	220,605	198,293	191,503	181,802	162,401	
Total Solids, Total Solids Load (lb-TS/d)	322,604	322,776	322,828	322,903	323,052	
Total Solids, Volatile Solids Load (lb-VS/d)	273,379	273,379	273,379	273,379	273,379	
Total Flow (gpd)	486,413	523,237	534,444	550,454	582,474	
Primary sludge percent of VS Load (%)	19%	24%	25%	27%	31%	

WAS percent of VS Load (%)	11%	13%	14%	15%	17%	
FOG percent of VS Load (%)	1%	1%	1%	1%	1%	
SSO percent of VS Load (%)	69%	62%	60%	57%	51%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	12	11	11	11	10	
Co-Digestion OLR (lbs-VS/d-cf)	0.35	0.35	0.35	0.35	0.35	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	168,898	151,816	146,617	139,190	124,336	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	220,080	214,109	212,291	209,695	204,503	
Total Sludge Effluent (gpd)	486,413	523,237	534,444	550,454	582,474	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	102,524	108,667	110,537	113,207	118,549	
Volatile Solids (Lbs-VS/d)	53,299	59,270	61,088	63,684	68,876	
Total Solids (% TS)	2.5%	2.5%	2.5%	2.5%	2.4%	
Volatile Solids (% VS)	52%	55%	55%	56%	58%	
Dewatered Solids (Lbs-TS/d)	97,398	103,234	105,010	107,547	112,622	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	221	235	239	244	256	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	3,040,162	2,732,685	2,639,105	2,505,419	2,238,047	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	3,951,199	3,841,497	3,808,109	3,760,413	3,665,020	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	220,782	198,452	191,656	181,948	162,531	
SSO Volatile Solids Load (lb-VS/d)	187,664	168,684	162,908	154,655	138,151	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	8,973	8,065	7,789	7,394	6,605	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	11,681	11,391	11,303	11,177	10,925	
Flow to Digeseter (MGD)	0.49	0.52	0.53	0.55	0.58	
Ammonium-N Conc. (mg/L)	2,880	2,610	2,536	2,435	2,249	
Ammonium-N (molar)	0.21	0.19	0.18	0.17	0.16	
Log Ammonia-N	-2.86	-2.90	-2.91	-2.93	-2.97	
Ammonia Concentration (mg-NH_3-N/L)	19.35	17.54	17.04	16.36	15.11	
Ammonia Concentration (mg-NH_3/L)	23.53	21.33	20.72	19.90	18.38	
Ammonia Toxcitiy Check	ok	ok	ok	ok	ok	

Brown and Caldwell

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-004
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - All Digesters in Service		

Co-digestion Assessment

10 day Thermophilic Digestion with All digesters in service

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	10	Assumed	Peaking Factors		
Number of Secondary Digesters	3	1	Maxium OLR (lbs-VS/cf-d)	0.35	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1				Peak Month	1.23	2
Volume of Secondary Digesters (MG)	0.3	1	Digester Temperature (F)	151	1	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS $_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)
PS Org. Nitrogen (lb-N/lb-TS)			TWAS Org. Nitrogen (lb-N/lb-TS)			Existing HSOW Org. Nitrogen (lb-N/lb-TS)		
PS Soluble Nitrogen (lb-N/lb-TS)			TWAS Soluble Nitrogen (lb-N/lb-TS)			Existing HSOW Soluble Nitrogen (lb-N/lb-TS)		

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing 10 day Thermophilic Digestion with All digesters in service Feed Assessment

	Annual Average	Peak Month	Peak Month	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	6.70	6.70	6.70	6.70	6.70	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	265,808	324,943	342,941	368,652	420,073	
Total Percent Solids Load (%)	4.6%	4.6%	4.6%	4.6%	4.6%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	25	21	20	18	16	
Base OLR (lbsVS/d-cf)	0.10	0.12	0.12	0.13	0.15	
Hydraulic Capacity (HC) (gpd)	403,942	344,807	326,809	301,098	249,677	*Assumes the minimum allowable HRT 10 days*
HC as Equivalent VS Load (lb-VS/day)	343,625	293,320	278,010	256,138	212,395	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	227,671	208,691	202,914	194,662	178,158	*Difference between max OLR (0.35 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	227,671	208,691	202,914	194,662	178,158	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	227,671	208,691	202,914	194,662	178,158	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	227,671	208,691	202,914	194,662	178,158	
SSO Total Solids Load (lb-TS/day)	267,848	245,519	238,723	229,014	209,597	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	267,848	245,519	238,723	229,014	209,597	
SSO (lb-wet/day)	2,232,069	2,045,990	1,989,357	1,908,453	1,746,645	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	2,232,069	2,045,990	1,989,357	1,908,453	1,746,645	
SSO (wtpd)	1,116	1,023	995	954	873	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	1,116	1,023	995	954	873	
SSO (gpd)	267,634	245,322	238,532	228,831	209,430	
HSOW No. 2 (gpd)	0	0	0	0	0	
SSO (gpd)	267,634	245,322	238,532	228,831	209,430	
Total Solids, Total Solids Load (lb-TS/d)	369,671	369,842	369,895	369,969	370,119	
Total Solids, Volatile Solids Load (lb-VS/d)	313,386	313,386	313,386	313,386	313,386	
Total Flow (gpd)	533,443	570,266	581,473	597,483	629,503	
Primary sludge percent of VS Load (%)	17%	21%	22%	24%	27%	
WAS percent of VS Load (%)	9%	12%	12%	13%	15%	
FOG percent of VS Load (%)	1%	1%	1%	1%	1%	
SSO percent of VS Load (%)	73%	67%	65%	62%	57%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	13	12	12	11	11	

Co-Digestion OLR (lbs-VS/d-cf)	0.35	0.35	0.35	0.35	0.35	
Process Check	OK	OK	OK	OK	OK	
Table X-X: Existing Mesophilic Solids and Biogas Production						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	265,808	324,943	342,941	368,652	420,073	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	2.3%	2.3%	2.3%	2.3%	2.3%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	
Table X-X: Mesophilic Co-digestion Solids and Biogas Production						
	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	204,904	187,822	182,623	175,196	160,342	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	256,086	250,115	248,297	245,701	240,509	
Total Sludge Effluent (gpd)	533,443	570,266	581,473	597,483	629,503	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	113,585	119,728	121,597	124,268	129,610	
Volatile Solids (Lbs-VS/d)	57,300	63,271	65,088	67,684	72,877	
Total Solids (% TS)	2.6%	2.5%	2.5%	2.5%	2.5%	
Volatile Solids (% VS)	50%	53%	54%	54%	56%	
Dewatered Solids (Lbs-TS/d)	107,906	113,741	115,517	118,055	123,129	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	245	259	263	268	280	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	3,688,271	3,380,793	3,287,213	3,153,527	2,886,156	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0		0	0	0	
Total Biogas Production (scfd)	4,599,308	4,489,605	4,456,218	4,408,521	4,313,128	
Table X-X: Nutrient Loading - Ammonia-N Estimates						
HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	267,848	245,519	238,723	229,014	209,597	
SSO Volatile Solids Load (lb-VS/d)	227,671	208,691	202,914	194,662	178,158	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	10,886	9,978	9,702	9,307	8,518	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	66	66	66	66	66	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.22	9.22	9.22	9.22	9.22	
Total Nitrogen (lb-N/d)	13,594	13,304	13,216	13,090	12,838	
Flow to Digeseter (MGD)	0.53	0.57	0.58	0.60	0.63	
Ammonium-N Conc. (mg/L)	3,056	2,797	2,725	2,627	2,445	
Ammonium-N (molar)	0.22	0.20	0.19	0.19	0.17	
Log Ammonia-N	-2.83	-2.87	-2.88	-2.90	-2.93	
Ammonia Concentration (mg-NH_3-N/L)	20.53	18.80	18.31	17.65	16.43	
Ammonia Concentration (mg-NH_3/L)	24.97	22.86	22.27	21.47	19.98	
Ammonia Toxcitiy Check	Toxic	ok	ok	ok	ok	

Date Checked	Checked By	Job Number	By	Date	Calc No
9/22/2017	Chris Muller	150871	Tracy Chouinard	9/15/2017	C-004
Project			Subject		
Encina Biosolids, Energy, and Emissions			2030 Year - All Digesters in Service		

Co-digestion Assessment

Thermal Hydrolysis with Mesophilic Digestion

Digester and Process Information

Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Number of Primary Digesters	3	1	Minium HRT (days)	12	Assumed	Peaking Factors		
Number of Secondary Digesters			Maxium OLR (lbs-VS/cf-d)	0.4	Assumed	Annual Average	1	2
Volume of Primary Digesters (MG)	2.05	1	Percent Solids Content of Digester Feed	9%	Assumed	Peak Month	1.23	2
Volume of Secondary Digesters (MG)			Digester Temperature (F)	102	Assumed	Peak 14 day	1.3	2
Digester Effliency Allowance (%)	5%	Assumed	Dewatering Total Solids (%TS)	22%	1	Peak 7 day	1.4	2
Digester pH	7.05	1	Dewatering Capture Rate (%)	95%	1	Peak day	1.6	2

Digester Sludge Feed

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge Flow (gpd)	177,844	1	Use if facility already receives HSOW (blank if not applicable)		
Primary Sludge Total Solids (%)	4.1%	1	HSOW Name	FOG	1
Primary Sludge Volatile Solids (%)	87%	1	FOG Flow (gpd)	8,700	1
TWAS Flow (gpd)	79,264	1	FOG Total Solids (%)	5.5%	1
TWAS Total Solids (%)	6%	1	FOG Volatile Solids (%)	80%	2
TWAS Volatile Solids (%)	80%	1	Are peaking factors applied to FOG?	No	
Domestic Sludge Biogas production yield (scf/lb-VS$_d$)	18	1	FOG Biogas production yield (scf/lb-VSd)	17.8	1

High Strength Organic Waste (HSOW)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
HSOW No. 1 Name	SSO	0	Percent of SSO (%)	100%	Assumed
HSOW No. 2 Name			Percent of (%)	0%	
SSO Total Solids (%)	12%	4	SSO Biogas production yield (scf/lb-VSd)	18	Assumed
SSO Volatile Solids (%)	85%	4	HSOW No. 2 Biogas production yield (scf/lb-VSd)		
HSOW No. 2 Total Solids (%)					
HSOW No. 2 Volatile Solids (%)					

Digester Volatile Solids Reduction (VSR)

Parameter	Input Values	Reference	Parameter	Input Values	Reference
Primary Sludge VSR (%)	65%	3	Account for Synergystic Affects?	No	
TWAS VSR (%)	47%	3	Synergystic Increase in Solids Reduction (%)		
FOG VSR (%)	90%	3			
SSO VSR (%)	90%	3			
Do not use this row					

Nutrients Speciation for Existing Conditions

Primary Sludge			TWAS			Existing HSOW (if applicable)		
Parameter	Input Values	Reference	Parameter	Input Values	Reference	Parameter	Input Values	Reference
Nitrogen Speciation			Nitrogen Speciation			Nitrogen Speciation		
PS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	TWAS Total Nitrogen (lb-N/lb-TS)	0.065	6 (TKN Content)	Existing HSOW Total Nitrogen (lb-N/lb-TS)	0.010	6 (TKN Content)

Nutrients Speciation for HSOW

Parameter	Input Values	Reference
Nitrogen Speciation		
SSO Total Nitrogen (lb-N/lb-TS)	0.063	4
HSOW No. 2 Total Nitrogen (lb-N/lb-TS)		
SSO Org. Nitrogen (lb-N/lb-TS)	0.058	4
HSOW No. 2 Org. Nitrogen (lb-N/lb-TS)		
SSO-Soluble Nitrogen (lb-N/lb-TS)	0.005	4
HSOW No. 2 Non-Soluble Nitrogen (lb-N/lb-TS)		
Maximum alloawable ammonia-N concentration (mg-N/L)	3,000	

Parallel Operation of Digesters

Table X-X: Existing Thermal Hydrolysis with Mesophilic Digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Peaking Factors	1.00	1.23	1.30	1.40	1.60	
Digester Volume (MG)	5.84	5.84	5.84	5.84	5.84	*Service condition assumes largest digester is out of service with the active volume of each digeser reduced to account for process inefficiencies.*
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
FOG Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
Total Digester Feed, Total Solids Load (lb-TS/d)	101,822	124,324	131,172	140,955	160,521	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
FOG Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Total Digester Feed, Volatile Solids Load (lb-VS/d)	85,715	104,695	110,471	118,724	135,228	
Primary sludge percent of VS Load (%)	62%	62%	62%	62%	63%	
WAS percent of VS Load (%)	35%	35%	35%	35%	35%	
FOG percent of VS Load (%)	4%	3%	3%	3%	2%	
Total Digester Feed Flow (gpd)	135,655	165,632	174,756	187,790	213,857	
Total Percent Solids Load (%)	9.0%	9.0%	9.0%	9.0%	9.0%	
Total Percent Volatile Solids Load (%)	84.2%	84.2%	84.2%	84.2%	84.2%	
Base HRT (days)	43	35	33	31	27	
Base OLR (lbsVS/d-cf)	0.11	0.13	0.14	0.15	0.17	
Hydraulic Capacity (HC) (gpd)	351,220	321,243	312,119	299,085	273,018	*Assumes the minimum allowable HRT 12 days*
HC as Equivalent VS Load (lb-VS/day)	298,776	273,275	265,513	254,426	232,251	*Equivalent load of HSOW, based on hydraulic capacity*
Organic Load Capacity (lb-VS/day)	226,718	207,738	201,962	193,710	177,205	*Difference between max OLR (0.4 lbs-VS/cf-d) and current load*
Process Limitation	Organic Load	Organic Load	Organic Load	Organic Load	Organic Load	

Table X-X: Mesophilic Co-digestion Feed Assessment

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Total HSOW Volatile Solids Load (lb-VS/day)	226,718	207,738	201,962	193,710	177,205	*Calculated available organic load, based on defined limit*
SSO Volatile Solids Load (lb-VS/day)	226,718	207,738	201,962	193,710	177,205	
HSOW No. 2 Volatile Solids Load (lb-VS/day)	0	0	0	0	0	
Total HSOW Volatile Solids Load (lb-VS/day)	226,718	207,738	201,962	193,710	177,205	
SSO Total Solids Load (lb-TS/day)	266,728	244,398	237,602	227,894	208,477	*Conversion to Total Solids load based on SSO %VS*
HSOW No. 2 Total Solids Load (lb-TS/day)	0	0	0	0	0	
SSO Total Solids Load (lb-TS/day)	266,728	244,398	237,602	227,894	208,477	
SSO (lb-wet/day)	2,222,730	2,036,651	1,980,018	1,899,114	1,737,306	*Conversion to Wet Solids load based on SSO %TS*
HSOW No. 2 Total Load (lb-wet/day)	0	0	0	0	0	
SSO (lb-wet/day)	2,222,730	2,036,651	1,980,018	1,899,114	1,737,306	
SSO (wtpd)	1,111	1,018	990	950	869	
HSOW No. 2 (wtpd)	0	0	0	0	0	
SSO (wtpd)	1,111	1,018	990	950	869	
SSO Digester Feed (gpd)	355,353	325,604	316,550	303,615	277,747	*Assume 9% TS*
HSOW No. 2 (gpd)	0	0	0	0	0	*Assume 9% TS*
SSO Digester Feed(gpd)	355,353	325,604	316,550	303,615	277,747	*Assume 9% TS*
SSO As Received(gpd)	266,514	244,203	237,412	227,712	208,310	*Assume 12% TS*
HSOW No. 2 (gpd)	0	0	0	0	0	*Assume 12% TS*
SSO As Received (gpd)	266,514	244,203	237,412	227,712	208,310	*Assume 12% TS*
Total Solids, Total Solids Load (lb-TS/d)	368,550	368,722	368,774	368,849	368,998	

Total Solids, Volatile Solids Load (lb-VS/d)	312,433	312,433	312,433	312,433	312,433	
Total Flow (gpd)	491,007	491,236	491,306	491,405	491,604	
Primary sludge percent of VS Load (%)	17%	21%	22%	24%	27%	
WAS percent of VS Load (%)	9%	12%	12%	13%	15%	
FOG percent of VS Load (%)	1%	1%	1%	1%	1%	
SSO percent of VS Load (%)	73%	66%	65%	62%	57%	
HSOW No. 2 percent of VS Load (%)	0%	0%	0%	0%	0%	
Check	ok	ok	ok	ok	ok	
Co-digestion HRT (days)	12	12	12	12	12	
Co-Digestion OLR (lbs-VS/d-cf)	0.40	0.40	0.40	0.40	0.40	
Process Check	OK	OK	OK	OK	OK	

Table X-X: Existing Mesophilic Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
Total Volatile Solids Destroyed (lb-VSd/day)	51,182	62,293	65,674	70,505	80,167	
Total Sludge Effluent (gpd)	135,655	165,632	174,756	187,790	213,857	*Assumes that volume in equals volume out*
Total Solids Effluent (Lbs-TS/d)	50,640	62,031	65,497	70,450	80,354	
Volatile Solids Effluent (Lbs-VS/d)	34,533	42,402	44,797	48,218	55,061	
Total Solids (% TS)	4.5%	4.5%	4.5%	4.5%	4.5%	
Volatile Solids (% VS)	68%	68%	68%	68%	69%	
Dewatered Solids (Lbs-TS/d)	48,108	58,929	62,222	66,927	76,337	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	109	134	141	152	173	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludge Biogas Production (scfd)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Biogas Production (scfd)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
Biogas Production (scfd)	911,037	1,108,812	1,169,005	1,254,994	1,426,972	

Table X-X: Mesophilic Co-digestion Solids and Biogas Production

	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	34,389	42,299	44,706	48,145	55,023	
WAS Volatile Solids Destroyed (lb-VSd/day)	13,919	17,121	18,095	19,487	22,271	
FOG Volatile Solids Destroyed (lb-VSd/day)	2,873	2,873	2,873	2,873	2,873	
SSO Volatile Solids Destroyed (lb-VSd/day)	204,047	186,965	181,766	174,339	159,485	
HSOW No. 2 Volatile Solids Destroyed (lb-VSd/day)	0	0	0	0	0	
Total Volatile Solids Destroyed (lb-VSd/day)	255,228	249,257	247,440	244,844	239,652	
Total Sludge Effluent (gpd)	491,007	491,236	491,306	491,405	491,604	*Assumes that volume in equals volume out*
Total Solids (Lbs-TS/d)	113,321	119,464	121,334	124,005	129,346	
Volatile Solids (Lbs-VS/d)	57,205	63,176	64,993	67,589	72,781	
Total Solids (% TS)	2.8%	2.9%	3.0%	3.0%	3.2%	
Volatile Solids (% VS)	50%	53%	54%	55%	56%	
Dewatered Solids (Lbs-TS/d)	107,655	113,491	115,267	117,804	122,879	*Dewatered cake assumes 95% capture rate*
Biosolids Cake (wtpd)	245	258	262	268	279	*Assumes biosolids cake has a solids content of 22% TS*
Primary sludgeVolatile Solids Destroyed (lb-VSd/day)	612,128	752,917	795,766	856,979	979,404	*Assumes a biogas yield of 17.8 scf/lb-VSd*
WAS Volatile Solids Destroyed (lb-VSd/day)	247,765	304,751	322,094	346,871	396,424	*Assumes a biogas yield of 17.8 scf/lb-VSd*
FOG Biogas Production (scfd)	51,145	51,145	51,145	51,145	51,145	*Assumes a biogas yield of 17.8 scf/lb-VSd*
SSO Biogas Production (scfd)	3,672,839	3,365,362	3,271,782	3,138,096	2,870,724	*Assumes a biogas yield of 18 scf/lb-VSd*
HSOW No. 2 Biogas Production (scfd)	0	0	0	0	0	
Total Biogas Production (scfd)	4,583,876	4,474,174	4,440,787	4,393,090	4,297,697	

Table X-X: Nutrient Loading - Ammonia-N Estimates

HSOW No 1	Annual Average	Peak Month	Peak 14 day	Peak 7 day	Peak day	Notes
SSO Organic Nitrogen Content (lb-N/lb-TS)	0.063	0.063	0.063	0.063	0.063	
SSO Total Solids Load (lb-TS/d)	266,728	244,398	237,602	227,894	208,477	
SSO Volatile Solids Load (lb-VS/d)	226,718	207,738	201,962	193,710	177,205	
SSO Nitrogen Content (lb-N/lb-VS)	0.053	0.053	0.053	0.053	0.053	
SSO Ammonium-N Load (lb-N/day)	10,840	9,932	9,656	9,262	8,473	
HSOW No 2						
HSOW No. 2 Organic Nitrogen Content (lb-N/lb-TS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Total Solids Load (lb-TS/d)	0	0	0	0	0	
HSOW No. 2 Volatile Solids Load (lb-VS/d)	0	0	0	0	0	
HSOW No. 2 Nitrogen Content (lb-N/lb-VS)	0.000	0.000	0.000	0.000	0.000	
HSOW No. 2 Ammonium-N Load (lb-N/day)	0	0	0	0	0	
Existing						
Primary Sludge						
Primary Sludge Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
Primary Sludge Total Solids Load (lb-TS/d)	60,812	74,799	79,056	85,137	97,299	
Primary Sludge Volatile Solids Load (lb-VS/d)	52,906	65,075	68,778	74,069	84,650	
Nitrogen Content (lb-N/lb-VS)	0.057	0.057	0.057	0.057	0.057	
Ammonium-N Load (lb-N/day)	1,957	2,407	2,544	2,739	3,131	
TWAS						
TWAS Total Nitrogen Content (lb-N/lb-TS)	0.065	0.065	0.065	0.065	0.065	
TWAS Total Solids Load (lb-TS/d)	37,020	45,534	48,125	51,827	59,231	
TWAS Volatile Solids Load (lb-VS/d)	29,616	36,427	38,500	41,462	47,385	
Nitrogen Content (lb-N/lb-VS)	0.052	0.052	0.052	0.052	0.052	
Ammonium-N Load (lb-N/day)	728	896	947	1,020	1,165	
Existing HSOW (if applicable)						
HSOW Total Nitrogen Content (lb-N/lb-TS)	0.010	0.010	0.010	0.010	0.010	
HSOW Total Solids Load (lb-TS/d)	3,991	3,991	3,991	3,991	3,991	
HSOW Volatile Solids Load (lb-VS/d)	3,193	3,193	3,193	3,193	3,193	
Nitrogen Content (lb-N/lb-VS)	0.008	0.008	0.008	0.008	0.008	
Ammonium-N Load (lb-N/day)	24	24	24	24	24	
Total						
Digester Temperature (deg C)	39	39	39	39	39	
Digester pH	7	7	7	7	7	
Ammonia/Ammonium -pKa	9.45	9.45	9.45	9.45	9.45	
Total Nitrogen (lb-N/d)	13,549	13,259	13,170	13,044	12,792	
Flow to Digeseter (MGD)	0.49	0.49	0.49	0.49	0.49	
Ammonium-N Conc. (mg/L)	3,309	3,236	3,214	3,183	3,120	
Ammonium-N (molar)	0.24	0.23	0.23	0.23	0.22	
Log Ammonia-N	-3.03	-3.04	-3.04	-3.04	-3.05	
Ammonia Concentration (mg-NH_3-N/L)	13.17	12.88	12.80	12.67	12.42	
Ammonia Concentration (mg-NH_3/L)	16.02	15.67	15.56	15.41	15.11	
Ammonia Toxcitiy Check	Toxic	Toxic	Toxic	Toxic	Toxic	

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Technical Memorandum

FINAL

Prepared for: Encina Wastewater Authority

Project Title: Biosolids, Energy and Emissions

Project No.: 150871.005.001

Technical Memorandum No. 5

Subject: Technology Evaluation for Waste Heat

Date: December 22, 2017

To: Scott McClelland, Assistant General Manager

From: Scott Lacy, Project Manager

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Limitations:

This document was prepared solely for Encina Wastewater Authority in accordance with professional standards at the time the services were performed and in accordance with the contract between Encina Wastewater Authority and Brown and Caldwell dated June 28, 2017. This document is governed by the specific scope of work authorized by Encina Wastewater Authority; it is not intended to be relied upon by any other party except for regulatory authorities contemplated by the scope of work. We have relied on information or instructions provided by Encina Wastewater Authority and other parties and, unless otherwise expressly indicated, have made no independent investigation as to the validity, completeness, or accuracy of such information.

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Executive Summary

The Encina Water Pollution Control Facility (EWPCF) currently has four 750-kilowatt (kW) (nameplate) internal combustion (IC) engines and a biosolids dryer, both of which produce heat. Recovered heat is utilized by the anaerobic digesters and an absorption chiller serving the Power Building while the remaining heat is wasted to plant effluent and atmosphere. This Technical Memorandum (TM) 5 provides an evaluation of alternative technologies for increasing heat utilization. The waste heat utilization technologies evaluated in this TM include:

- Absorption and adsorption chillers
- Organic Rankine Cycle (ORC)
- Small-scale steam turbines
- Gasification of biosolids
- Thermophilic digestion or thermal hydrolysis process (THP)

Screening and ranking of technologies was performed in a workshop with Encina Wastewater Authority (EWA) staff on August 16, 2017. The project team applied a fatal-flaw test to all alternatives and technologies that did not pass the fatal-flaw filter were eliminated. Technologies that passed the fatal-flaw filter, namely thermophilic digestion/thermal hydrolysis process (THP) and small-scale steam turbines, were assessed using evaluation criteria developed to reflect EWA's values and goals for the project (Table ES-1). Heat utilization alternatives that received an overall score of 3 or higher in the scoring evaluation will be further refined and analyzed using Brown and Caldwell's (BC's) Solids Water Energy Evaluation Tool (SWEET).

Section 1: Introduction

EWA has undertaken a Biosolids Energy and Emissions Plan (BEE Plan) which will be used to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed Process Master Plan. The BEE Plan has several goals:

1. Provide a comprehensive analysis of all project elements including biosolids treatment, gas use, energy generation, and waste heat;
2. Address capacity limitations in the solids handling process at the EWPCF;
3. Assess which alternative is likely to be the most cost effective and sustainable solution for EWA;
4. Move the EWPCF toward greater energy independence; and
5. Reduce greenhouse gas emissions.

The purpose of TM 5 is to conduct a technology screening for increasing heat utilization for a beneficial purpose rather than wasting it. This TM does not provide an alternatives analysis, but does provide insight to the methodology and rationale used to select alternatives which will move forward for further analysis in the SWEET model development.

1.1 Purpose and Scope

This TM is preceded by TM 1 which addressed the baseline energy and heat profiles and projections, established a mass balance for the solids handling system, and evaluated sludge flows and loads projections performed under the Process Master Plan. Screening and evaluation of solids processing and power production technologies are described in TMs 1, 2 and 3, including derivation of the heat projections used in the alternatives evaluation presented in this TM.

TM 5 summarizes the methodology for screening and evaluating heat utilization technologies, the technologies evaluated, and how these alternatives were ranked to determine which would move forward in the SWEET analysis. Recommended technologies will be advanced for further analysis and will be combined with the solids handling and waste heat alternatives presented in TMs 2 and 3. Screening and ranking of technologies were performed in a workshop with EWA staff on August 16, 2017. Meeting minutes from this workshop have been provided as Attachment A.

1.2 Background Information

The EWA cogeneration system has four Caterpillar 3516 IC engine-generators installed in the Power Building; each engine-generator has a nameplate electrical output of 750 kW. One of the four IC engines at the EWPCF serves as a standby unit in the event another IC engine must be shut down. Thus, three IC engines are available for cogeneration.

IC engine operation is permitted by San Diego Air Pollution Control District. EWA received a revised air permit, dated November 8, 2017, allowing utilization for a total of 280 million standard cubic feet (scf) of digester gas (DG) and natural gas (NG) per year to fuel the IC engines. The permit limits NG consumption to 28 million scf per year (scf/year)—or 10 percent by volume. Under the previous air permit, EWA was allowed to utilize 224 million scf of DG and NG per year for the IC engines, and NG consumption could not exceed 22.4 million scf/year. The fuel consumption limits of the previous permit allowed only two of the four IC engines to be used during typical operation. However, there were times when the plant ran a third engine and physically disconnected from the grid during peak demand periods to avoid high power charges.

EWA pursued modifications to its air permit to allow the entire use of the current biogas in the IC engines and increase the generating capacity of the plant. A summary of current and future EWPCF biogas projections is shown in Table 1-1. These projections assume high strength waste (HSW) quantities do not increase and are discussed in greater detail in TM 1. The new air permit increases the DG and NG usage limit to approximately 533 scf per minute (scfm), which exceeds the current biogas production with the increased quantities of HSW the plant recently began accepting. As a result, the equivalent of 2.5 engines may be operated continuously; thus, increasing the amount of waste heat that can be recovered.

Table 1-1. Projected Biogas Production

Unit Measurement	Current	2020	2030	2040
scfm	501	528	619	709
therms/year[1]	1,581,000	1,666,000	1,951,000	2,235,000

1. *Based on 600 Btu/ft³ LHV*

Following TM 1, BC reevaluated the current heat production and demand values. The reevaluation suggests the existing mesophilic digesters likely require 2.1 to 2.4 million British thermal units (MMBtu) per hour (MMBtu/hr), total, rather than the initially estimated 1.2 MMBtu/hr. With the old permit, the engines recover around 5.3 MMBtu/hr rather than the initially estimated 6 MMBtu/hr. When the new permit conditions are applied, approximately 6 to 7 MMBtu/hr of heat can be recovered from the engines. A summary of these projections is provided in Table 1-2. Excess heat can be beneficially used for various purposes, which will be discussed in Section 2.

Table 1-2. Heat Production and Usage				
	Baseline TM 1		Revised Projections	
	Production, MMBtu/hr	Usage, MMBtu/hr	Production, MMBtu/hr	Usage, MMBtu/hr
Engines	6.0	-	6.0 – 7.0	-
Dryer/RTO	1.4	-	1.4	-
Digesters	-	1.2	-	2.3
Total	7.4	1.2	7.4 – 8.4	2.3

Section 2: Identification of Technologies for Waste Heat Utilization Production

The BC team identified and evaluated technologies to utilize the excess heat generated by the IC engines. Alternative technologies include the following:

- Small scale steam turbines
- Thermophilic digestion or THP
- Absorption and adsorption chillers
- ORC
- Gasification of biosolids

These technologies are discussed in subsequent sections in further detail. The waste heat technologies were first screened using four fatal flaw criteria that were developed in conjunction with EWA staff. The four fatal flaw screening criteria include the following:

1. **At least one successful North American installation of technology.** There must be at least one full-scale installation of the technology at a wastewater treatment plant (WWTP) in North America.
2. **At least one successful installation and operation in a facility of similar size.** The technology should be sufficiently developed that it is applicable at a facility of comparable size to EWPCF to ensure compatibility.
3. **Available space.** The technology must be accommodated within the limited available footprint at EWPCF.
4. **Compatibility with plant site and any existing equipment.** The technology must be capable of being integrated into the existing treatment plant infrastructure.

For an alternative to be considered for the ranking process, it must pass all four fatal flaw criteria.

2.1 Small-Scale Steam Turbines

A small-scale steam turbine system uses a steam boiler to combust any excess DG and produce steam. Instead of using a pressure regulator to reduce the pressure of the outlet steam, a small back-pressure steam turbine and generator is installed to generate electricity. After passing through the turbine, steam can be used to transfer excess heat to the digesters or a THP system. A basic diagram of this process is presented in Figure 2-1. If steam is not consumed, it can be recycled in a Rankine cycle, which would require a condenser unit, waste heat removal, a pump, and other associated equipment.

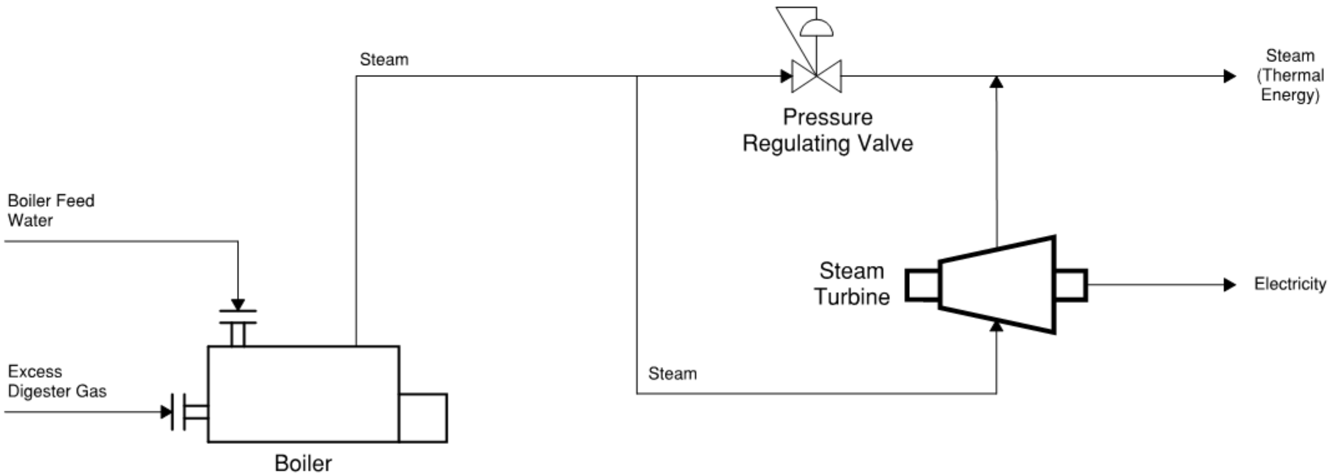

Figure 2-1. Small-scale steam turbine system process flow diagram.

Engine waste heat can also be utilized in this process in a composite boiler to preheat boiler feed water upstream of where the water enters the DG or NG fired chamber. Preheating the feed water reduces DG or NG consumption. A simplified flow diagram of the small-scale steam turbine system with a composite boiler is shown in Figure 2-2.

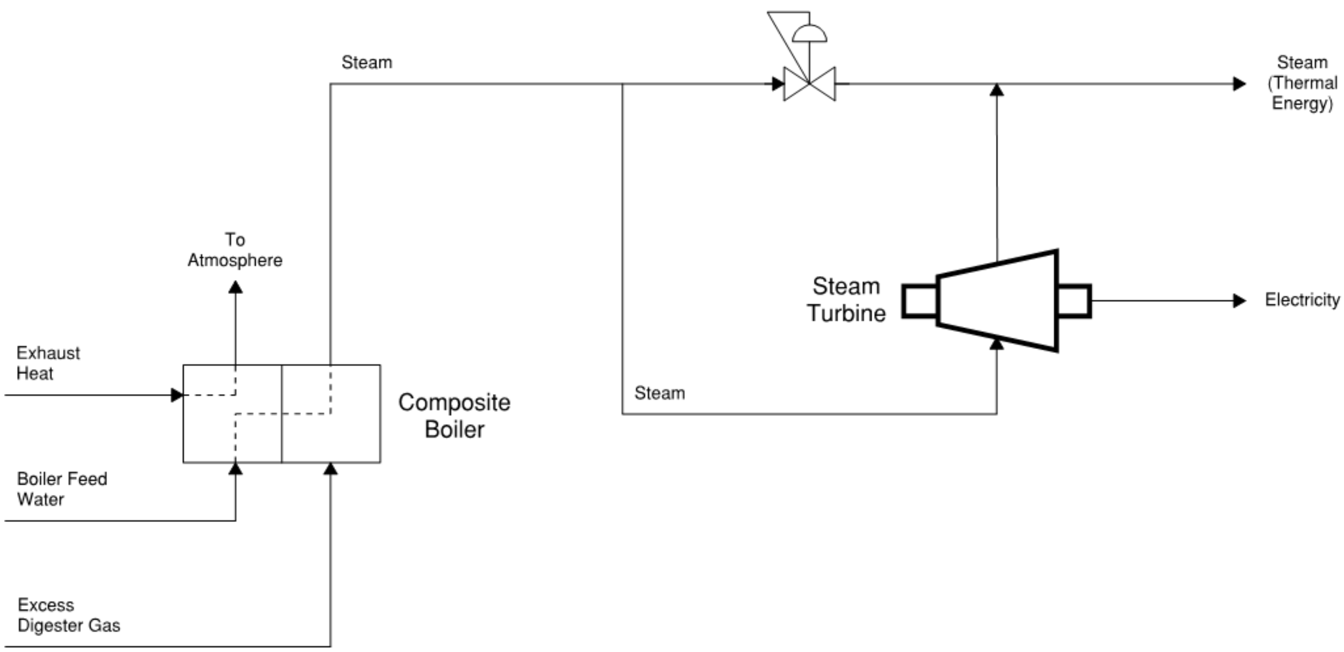

Figure 2-2. Small-scale steam turbine system and composite boiler process flow diagram.

This type of small-scale steam turbine system has not been employed at any WWTPs in the U.S., but this process can be readily applied. These systems have been successfully installed by NLine Energy at hospitals and other large-scale industrial settings to take the place of pressure regulators in the steam heat systems. In addition, boilers and steam turbines are proven technologies, are available at competitive market prices, and have a relatively small footprint. Small-scale steam turbines can be cost effective when paired with an existing steam system, but EWPCF only uses hot water for heating services. Adding a steam system for the sole purpose of running a steam turbine is not cost effective; a conceptual order of magnitude cost estimate for adding a steam system and steam turbine is $1 million. Such a system would only be compatible at EWPCF if a process that requires steam, such as THP, is installed.

2.2 Thermophilic Digestion or Thermal Hydrolysis Process

Thermophilic digestion or THP would allow for additional utilization of engine waste heat, as well as benefits to the digestion process. These alternate solids stabilization technologies are summarized in greater detail in TM 2.

Thermophilic digestion, which selects organisms with favorable digestion kinetics at thermophilic temperatures targeted at 135 degrees Fahrenheit, is an alternative to the existing mesophilic digestion which operates between 95 and 100 degrees Fahrenheit. To achieve thermophilic temperatures, additional engine exhaust heat would need to be recovered through the plant hot water loop and transferred to the digesters via installing more heat exchangers and larger hot water pumps. It should also be noted that the temperature of the hot water needed for thermophilic digestion is generally higher than for mesophilic digestion, and recoverable heat drops as the recovery temperature rises. A more detailed evaluation should be performed to determine how much heat would be available from the existing engines if thermophilic digestion is considered further. Changes to the overall heat loop may be required, as well. Other treatment plants that recover engine waste heat for thermophilic digestion include Hyperion in Los Angeles, California; East Bay Municipal Utilities District in Oakland, California; Oceanside Treatment Plant in San Francisco, California; and the Annacis Island Treatment Plant in Vancouver, British Columbia.

In THP, sludge is heated to around 165 degrees Celsius (330 degrees Fahrenheit) at an elevated pressure using direct steam injection, followed by a sudden drop in pressure. This process improves digestion performance by breaking down sludge to make it more accessible to microbes during digestion. In general, IC engine exhaust heat is a poor source for making steam, while boilers and gas turbines have had more success. Exhaust heat from IC engines can, however, be utilized to preheat feedwater prior to producing steam in a boiler for THP or in a composite boiler.

Modifying EWPCF to accommodate a THP system would require a larger footprint than upgrading the mesophilic digesters to thermophilic digesters because THP requires additional ancillary equipment. However, as stated in TM 2, the EWPCF has room to accommodate the additional footprint of a THP system. Heat recovery equipment that would be associated with THP (i.e., steam or composite boilers) would have a relatively minor footprint. If steam boilers are used, a heat exchanger would be required to transfer waste heat from the IC engine to the boiler feedwater. If a composite boiler is used, engine exhaust could be introduced directly to the boiler to increase the feedwater temperature and reduce the DG or NG requirement. Multiple manufacturers have developed THP systems (Cambi, Veolia, etc.) at municipal WWTPs in the U.S. and Europe. For example, the District of Columbia Water and Sewer Authority (DC Water) in Washington, D.C. has a Cambi THP system which uses cogeneration steam to provide heat for the Cambi process.

There are multiple plants that operate thermophilic digesters or THP systems using waste heat from IC engines that have been in operation for longer than 5 years. The additional heat recovery equipment required for THP (e.g., heat exchangers, pumps, and boilers) has a relatively small physical footprint and can be installed within available space at EWPCF. If advanced digestion technologies are selected as part of the stabilization technology, waste heat from the engines can be recovered for a beneficial purpose. For these reasons, thermophilic digestion or THP passes the fatal flaw filter.

2.3 Absorption and Adsorption Chillers

Recovered heat from IC engines can also be used as part of the refrigeration cycle of absorption and adsorption chillers. Hot water or steam gaining energy from the IC engine waste heat is used to vaporize a refrigerant which has been absorbed or adsorbed in the chiller so that it can be recycled after subsequent condensation.

Absorption and adsorption chillers operate under similar principles; the primary difference is the sorbent compound that is used to capture the vaporized refrigerant. Absorption chillers use a fluid absorbent whereas adsorption chillers use a solid adsorbent. A general absorption cycle process flow diagram is presented in Figure 2-3. Other important differences to consider are that adsorption chillers are typically more expensive and less efficient but have significantly longer life expectancies.

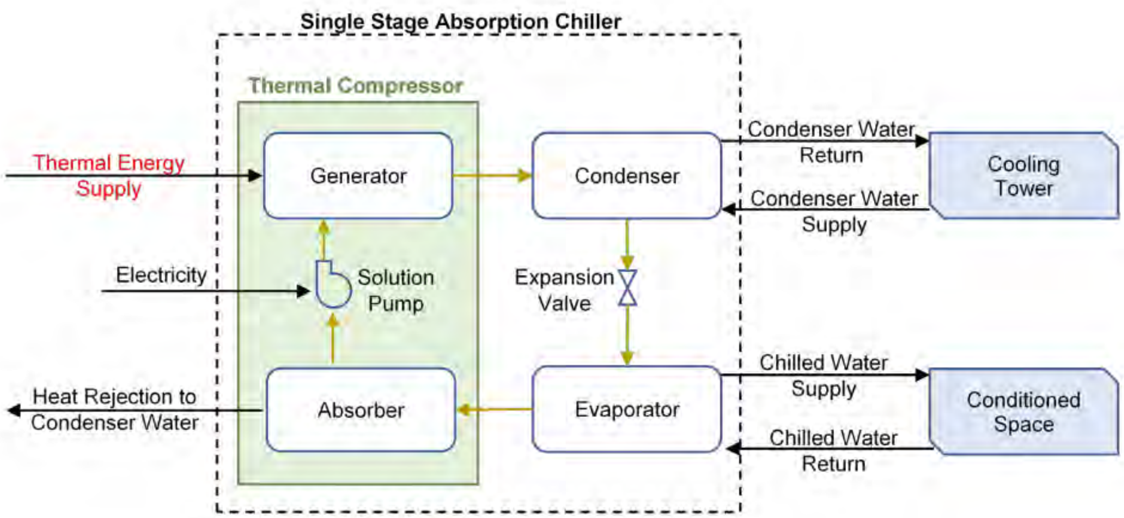

Figure 2-3. Absorption cooling process flow diagram.

Source: U.S. Department of Energy Fact Sheet.

Absorption and adsorption chillers can be applied as air conditioning systems or as chilling systems for equipment and processes. These two types of systems can be provided in various sizes and configurations with cooling capacities ranging from 4.5 kW to 5 megawatts (MW). The wide range of cooling capacities allows for adsorption and absorption chillers to utilize as much waste heat as needed. These technologies are proven and have been applied in various forms and industrial settings since the early 1900s.

BC understands that the plant is moving from adsorption chillers to a centralized heating, ventilation, and air conditioning (HVAC) systems; therefore, this alternative fails the fatal flaw filter on compatibility and will no longer be evaluated moving forward.

2.4 Organic Rankine Cycle

ORC is a thermodynamic process in which waste heat is transferred to an organic fluid with a boiling point lower than water at a constant pressure. The organic fluid then vaporizes and expands in a vapor turbine to drive a generator, producing electricity. Cooled vapor is then condensed back to liquid state and recycled through the system via a pump. Figure 2-4 shows a schematic of how the ORC process operates when interconnected with an IC engine. As presented in Figure 2-4, ORC systems require a substantial cooling water stream to condense the organic working fluid after it exits the turbine. Overall, ORC systems have a relatively low efficiency in converting excess thermal energy to electrical power. Average overall ORC efficiencies are between 10 and 12 percent when applied at WWTPs for waste heat usage.

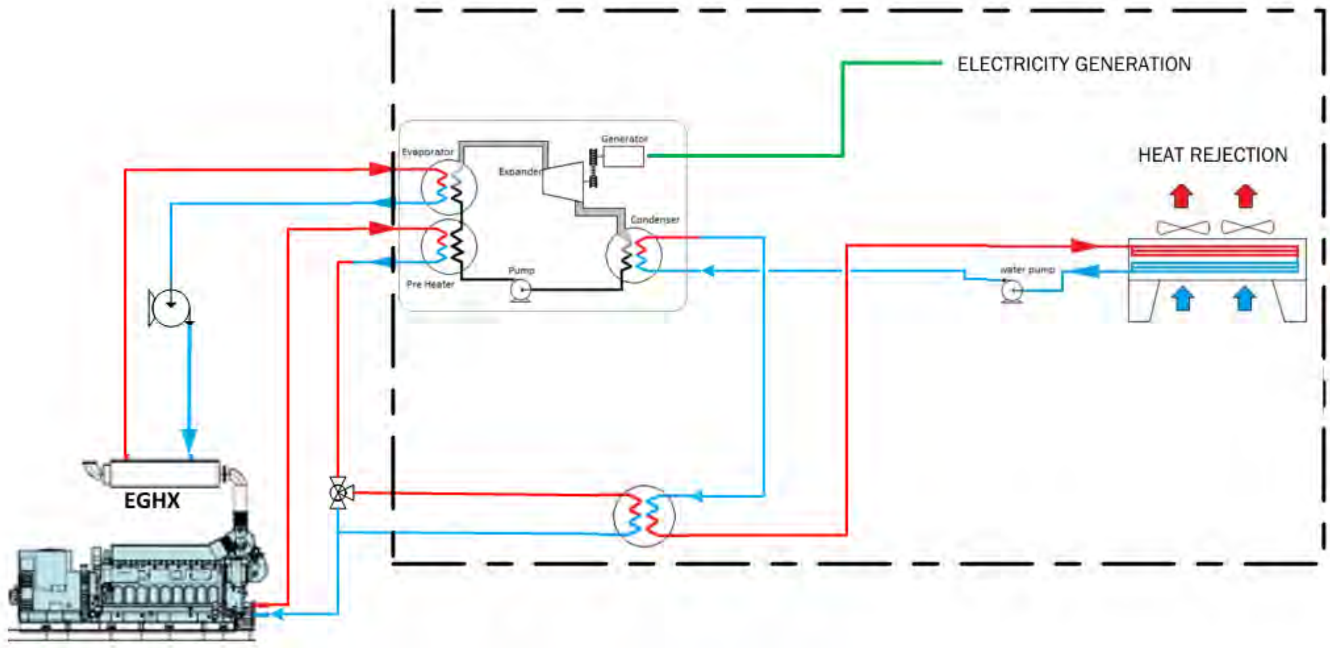

Figure 2-4. Process flow diagram detailing the ORC.

Source: ElectraTherm.

Turboden (Italian brand) and ElectraTherm (U.S. brand) are the two main manufacturers that supply ORC systems to the U.S. ORC systems have been installed at multiple WWTPs in Europe. In the U.S., ORC systems have been installed at biomass processing plants and oil and gas operations but only one WWTP—the Albany County Sewer District (ACSD) North Plant in New York. The ACSD North Plant is a 35-million gallons per day (mgd) WWTP, similar in size to the EWPCF, and waste heat is generated by sludge combustion in an incinerator. The generated waste heat is used to create steam and run ACSD North Plant's Turboden ORC system, which has an installed capacity of 925 kW. The ACSD North Plant ORC application is not analogous to an ORC process that uses waste heat from an internal combustion engine because engine cogeneration produces significantly less heat than incineration at this scale.

The ORC is still considered an emerging technology with limited operating experience at WWTPs similar in size to EWA's; therefore, ORC does not pass the fatal flaw filter. Additionally, the parasitic loads associated with the large cooling water flow requirement significantly reduce the benefits provided by an ORC system.

2.5 Gasification of Biosolids

Gasification of biosolids is a high temperature, thermal conversion process that produces a combustible gas mixture of hydrogen, carbon monoxide, and carbon dioxide. Gasification at EWPCF would take biosolids exiting the thermal dryer and combine them with waste heat from the IC engines to perform the reaction. The end products of gasification are ash and syngas, which is a combustible gas with a lower heating value between 100 and 300 Btu per standard cubic foot. Syngas can likely be used in the IC engines but would require upstream conditioning and engine modification for the very low Btu fuel.

Gasification of biosolids is still considered an emerging technology because there are not full-scale installations at municipal WWTPs. The plant in Sanford, Florida, recently ceased operations because the solids processing company (Maxwest Environmental) filed for bankruptcy. With the limited operating history, gasification of biosolids does not pass the fatal flaw filter.

2.6 Fatal Flaw Conclusions

Waste heat technologies that pass the fatal flaw criteria include small-scale steam turbines and recovery of waste heat for thermophilic digestion or thermal hydrolysis. Both technologies have been successfully operated at WWTPs and align with the existing systems at EWPCF and available plant area. These alternatives are ranked using the evaluation and scoring criteria in Section 3 to determine if they should be analyzed further using BC's SWEET tool.

Absorption and adsorption chillers fail the fatal flaw filter because EWA plans to replace the existing adsorption chillers with a central HVAC system. ORC systems and biosolids gasification fail the fatal flaw filter because both technologies have limited operating experience at large-scale WWTPs.

The results of the fatal flaw evaluation are provided in Table 2-1.

Table 2-1. Waste Heat Technology Fatal Flaw Evaluation

	Technology Maturity	Successful Operation	Available Space	Compatibility
Small-Scale Steam Turbines	Pass	Pass	Pass	Pass
Use for Thermophilic Digestion/THP	Pass	Pass	Pass	Pass
Absorption and Adsorption Chillers	Pass	Pass	Pass	Fail
ORC	Fail	Fail	Pass	Pass
Gasification of Biosolids	Fail	Fail	Pass	Pass

Section 3: Ranking of Screened Technologies

This section describes the results of applying the evaluation criteria described in Section 2 to further screen and rank the technologies that passed the fatal flaw filter.

3.1 Introduction

Following application of the fatal flaw filter, Table 3-1 summarizes the technologies that were further evaluated using established criteria. The final scores and weightings were fixed in Workshop 2 with EWA staff. In this analysis, a weighted average score of 3 or less led a technology to be eliminated from further consideration. The rationale behind the scoring for each technology area is described in this section.

3.2 Criteria Descriptions and Weightings

Alternatives that passed the fatal flaw filter were further evaluated and ranked based on both economic and non-economic screening criteria. The BC team worked with EWA staff to develop a series of evaluation criteria that reflect the project goals, EWA's values, and EWA's general operational practices. Criteria weights were assigned in Workshop 2 with EWA staff. Criteria and weightings are presented in Table 3-1.

Table 3-1. Criteria and Weight for Technology Screening[1]			
Criterion	Description	Scoring Description	Weight
Proven Technology Performance	Proven and reliable technology with same configuration intended at Encina. Long successful operating track record.	Low score indicates no successful large-scale operating installations in North America or Europe, no successful demonstration scale installations in North America or Europe, and unknown safety or reliability record. High score indicates more than one successful operating installation in North America or Europe, more than one operating installation at a WWTP of at least 40 mgd in North America or Europe, track record duration greater than 5 years, and vendors in Western U. S.	20%
Minimize Life-Cycle Costs	Qualitative metric of program cost. Capital and O&M costs based on existing EWA data or similar experience at other WWTPs.	Low score indicates high capital cost to build on-site facilities and high O&M costs. High score indicates low capital cost to build on-site facilities and low O&M costs.	10%
Energy/Resource Recovery	Increases biogas production through advanced digestion. Supports co-digestion of organic waste. Recovery of renewable energy.	Low score indicates high energy requirement for on-site technology, no increase in biogas production, technology does not recover energy as biogas, no recovery of renewable energy in biosolids, and no biosolids resource recovery. High score indicates a higher biogas production, compatible with co-digestion of organic waste, and biosolids resource recovery.	25%
O&M Impacts	Impacts to existing plant O&M staff levels. Complexity of new technology O&M and control systems. Reliability of new technology (potential downtime). Minimal impacts to plant safety.	Low score indicates more O&M time required, complex mechanical and control systems required compared with existing plant facilities, potential equipment downtime, and new chemicals or hazards. High score indicates reduction in O&M staff time required, new technology is simple to operate and maintain, reliable with minimal downtime, and no new chemicals or hazards.	10%
Environmental Impacts	Impacts to carbon footprint and air permitting.	Low score indicates high carbon footprint for technology, and new permitting for environmental regulatory requirements. High score indicates low carbon footprint for technology and no additional permitting for environmental regulatory requirements.	15%
Community and Stakeholder Impacts	Minimize nuisance impacts such as dust, odors, vectors, aesthetics, noise and traffic. Assess impacts to partner agency issues/values as well as local planning codes and requirements.	Low score indicates nuisance factors for on-site technology are difficult to mitigate. High score indicates nuisance factors can be mitigated at plant site.	10%
Project Site Compatibility	Assess compatibility of technology with available plant footprint. Incorporation into existing treatment process.		10%

1 Criteria are scored on a scale of 1-5, with 5 being the highest.

O&M = operations and maintenance

3.3 Results and Discussion

Table 3-2 shows the scoring results for the waste heat utilization technologies that passed the fatal flaw filter. Use of waste heat for advanced digestion technologies received a higher score in every rating criteria over small-scale steam turbines. Rationale behind the scoring for each alternative is described below.

Thermophilic digestion is a proven process that could increase the plant's capacity to accept high strength waste. Because the additional heat demands can be satisfied by the existing cogeneration system, this specific use of waste heat minimizes life-cycle costs by generating tipping fee revenue and increasing DG production with few negative impacts.

THP in conjunction with mesophilic digestion can produce a Class A biosolids product, but requires steam to bring the inlet sludge up to high process temperatures. Waste heat from the cogeneration process can help offset this heat demand.

Small-scale steam turbines are an emerging technology. Newer versions of this equipment are more efficient than historical models, which makes the technology cost effective in place of traditional pressure regulating valves. The small-scale steam turbine may be most effective if combined with a THP system because both require steam.

Utilizing engine waste heat for either thermophilic digestion or THP is an established practice at several large WWTPs in the U.S. The process for thermophilic digestion is similar in concept to mesophilic digestion, with a hot water loop and heat exchangers. At the DC Water plant, heat is recovered in the form of steam to satisfy the high-quality heat demand of THP.

Recovering additional heat for use in thermophilic digestion does not have a significant capital cost, nor does it add a major O&M burden. Because EWPCF does not have an existing steam heat system, recovering heat for THP requires significant capital investment to install equipment for generating steam for and delivering steam to the THP system. In comparison, the cost to install a small-scale steam turbine relative to the increased power production has a higher cost to benefit ratio.

An air permit is required for both THP and small-scale steam turbines because a new boiler is required to produce steam. Air permitting requirements for boilers are presented in TM 6.

Table 3-2. Waste Heat Technologies Evaluation

Criterion	Small-Scale Steam Turbines	Thermophilic Digestion/THP
Proven Technology Performance	2	5
Minimize Life-Cycle Costs	3	5
Energy/Resource Recovery	4	4
O&M Impacts	3	3
Environmental Impacts	3	4
Community and Stakeholder Impacts	3	4
Project Site Compatibility	3	4
Weighted Score	3.05	4.20

Section 4: Conclusions and Next Steps

Screening of heat utilization alternatives resulted in a final selection of technologies to be included in end-to-end alternatives and are summarized in the list below. These technologies will be combined with the results of Tasks 2, 3, and 4 for the creation of end-to-end alternatives for analysis in the SWEET model. Factors influencing solids stabilization will be paired with the heat utilization technologies, if applicable, to aid in selection of the best overall alternative. Development of end-to-end alternatives will be performed in cooperation with EWA staff prior to analysis. The shortlist of alternatives to be carried forward in SWEET analysis consists of small-scale steam turbines, in conjunction with THP, and providing heat to thermophilic digestion or THP.

Attachment A: Workshop Meeting Minutes

Screening and Ranking of Technologies, August 16, 2017

Meeting Minutes

9665 Chesapeake Drive, Suite 201
San Diego, CA 92123

T: 858.571.8822
F: 858.571.8833

Prepared for: Encina Wastewater Authority
Project Title: Energy & Emissions Strategic Plan & Biosolids Management Plan Update
Project No.: 150871

Purpose of Meeting: Workshop #2 **Date:** August 16, 2017
Meeting Location: Encina Wastewater Authority **Time:** 1:30 – 5:00 PM
Minutes Prepared by: Hari Seshan and Jocelyn Lu, Brown and Caldwell

Attendees:

Doug Campbell, Encina, JPA	Adam Ross, Brown and Caldwell
Scott McClelland, Encina JPA	Hari Seshan, Brown and Caldwell
Jimmy Kearns, Encina JPA	Jocelyn Lu, Brown and Caldwell
Mike Steinlicht, Encina JPA	Natalie Sierra, Brown and Caldwell
Octavio Navarrete, Encina JPA	Scott Lacy, Brown and Caldwell
Nathan Chase, RMC	Tom Chapman, Brown and Caldwell

Attachments:

- Workshop #2 Presentation Slides

Decisions

The following is a list of decisions made as a result of the meeting discussion:

- BC team to evaluate RDTs against the current status quo of primary clarifier and DAFT.
- Stabilization technologies that moved to the next round of evaluation: Mesophilic Digestion, Mesophilic Digestion with High Solids, Thermophilic Digestion, and Traditional CAMBI.
- Dewatering technologies that moved to the next round of evaluation: Centrifuges and Belt Presses.
- Post-dewatering technology that moved to the next round of evaluation: Thermal Drying - High Quality (Drum Dryer).
- Alternative power production technologies that moved to the next round of evaluation: Internal Combustion Engines (Status Quo), Internal Combustion Engines – with Gas Conditioning, Internal Combustion Engines – with Exhaust Treatment, Digester Upgrading – Pipeline Injection, Micro-Turbines, Biosolids Drying – Direct Use of Biogas, Large Scale Photovoltaics (PV), Small Scale Rooftop PV.
- Waste heat technologies that moved to the next round of evaluation: Small-Scale Steam Turbines, and Thermo/THP.

Action Required

The following is a list of actions required as a result of the meeting discussion:

- Jimmy to send Adam maintenance schedule costs.
- Octavio to send WAS daily flow data to Hari Seshan (Hari).
- Scott L to send list of additional data/document requests over to Scott M after updating based on discussion.
- Scott M to send a list of EWA attendees for the Waste Haulers Meeting to BC.
- Adam to send a draft agenda of the Waste Haulers meeting to EWA and finalize per any EWA comments.
- Octavio to send EWA's SDG&E point of contact to Adam. EWA and BC to discuss initial contact with SDG&E regarding biomethane pipeline injection.
- Octavio to send Hari lab data on the performance of the centrifuges.
- Tom to work with Octavio on refining the solids mass balance.
- Adam to present a big picture view of the power production alternatives at the next workshop.
- BC to identify technologies that would be beneficial to visit at WEFTEC.
- BC will set up a meeting with Anaergia to discuss project goals and opportunities. This meeting will be separate from the Waste Hauler meeting.
- Scott L and Scott M will schedule Workshop 3 for mid-September – aim for conducting the Waste Hauler meeting on the same day.
- EWA will take the dryer out of service in September/October. BC requests that any condition assessment results be shared with the team – particularly related to the increased use of digester gas (siloxane or hydrogen sulfide issues).
- BC to check in with EWA to confirm is any support is needed related to the next board meeting on Oct 11.

Summary

Workshop #2 was held for the Encina Water Authority (EWA) Energy & Emissions Strategic Plan & Biosolids Management Plan Update. The purpose of this Workshop was to review pending administrative tasks and provide task updates. A summary of the discussion is provided below:

Introductory Items

BC started off the meeting by reviewing the schedule and goals for the meeting. The goals are to generate content and direction for the project team moving forward.

- This month, the Brown and Caldwell (BC) team will be:
  - Preparing a baseline report, to be reviewed by EWA in September.
  - BC will also be preparing report sections of Tasks 2 and 3 by September.
  - In October and November, BC will be developing SWEET alternatives and providing more clarity on how the pieces interact.
- Adam Ross (Adam) stated that he expects to have more questions about permitting, cogeneration (cogen), electrical rates, and where to send digester gas, and would appreciate dialogue between now and the next workshop. EWA staff recommended for him to work with Octavio Navarrete (Octavio).

New Data Request Items

BC reviewed new data request items with EWA. They included:

- Trussell food waste capacity report - Scott McClelland (Scott M) stated that he has the data, but not the report, on the Trussell study. Preliminary conclusions of the report indicate that EWA could accept an additional 80,000 gal/week of FOG and 25,000 gal/week of brewery waste. EWA expect it'll take about another month before the report is ready. Imported wastes are received Monday – Friday/Saturday. A constant feed to the digesters is provided until around Saturday afternoon. A potential limitation to high strength waste acceptance is truck offloading capacity. A food waste pilot program began on Monday, 9/14.
- O&M costs for cogen engines - Adam asks if EWA has annual O&M costs for the engines. Jimmy Kearns (Jimmy) states that EWA has annual costs for the maintenance schedule.
    - **ACTION: Jimmy to send Adam maintenance schedule costs.**
- WAS flow data
    - BC requests the WAS flow data, and Octavio indicates that EWA does have that data.
    - **ACTION: Octavio to send WAS daily flow data to Hari Seshan (Hari).**
- Air permitting summaries or progress
    - Doug Campbell (Doug) sent Adam the latest email from Don King (Don).

Outstanding Data Requests

BC reviewed outstanding data requests with EWA. They included:

- Cogen drawing and cut-sheets
    - Natalie Sierra (Natalie) points out that BC has received drawings from Andritz.
- Information on energy management
- High strength waste storage (typical day operating procedure)
- **ACTION: Scott L to send list of additional data/document requests over to Scott M after updating based on discussion.**

There was a subsequent discussion on wasted gas that was being flared. Octavio explains that the operators need to manually control the digester gas flow to the dryer, which results in some flaring. Operators generally try to set the digester gas flow rate to avoid drawing down the gas system and triggering natural gas blending at cogen. This typically results in a conservative offtake of digester gas to the dryer which results in some flaring. Mike Steinlicht (Mike) asks how much is being flared, and Adam calculated that about 180 kW of gas was being flared (averaged over a month) in current operation.

Cogeneration operation was discussed. EWA operates two engines on digester gas 24/7. A third engine operates on natural gas during peak power rates. EWA physically disconnects from the power grid to avoid demand and consumption charges.

FOG is fed to the digesters at a constant rate of 12 gallons per minute. FOG is fed to only one or two digesters, not all. The FOG feeding begins on Monday with first deliveries of the week, and continues into Saturday to pump down material from the last deliveries on Friday.

<u>Meeting with Waste Haulers</u>

BC reviewed the timing, attendees, and goals of the Waste Haulers Meeting. Below is a summary of the discussion:

- Scott L reviewed the potential list of attendees, which included: EWA representatives, BC representatives, Waste Management (WM), Republic, EDCO, and potentially LES or Anaergia.
  - **ACTION: Scott M to send a list of EWA attendees for the Waste Haulers Meeting to BC.**
- Scott M stated that the intent of the meeting is to develop a public-private partnership and noted increase grant eligibility by having this kind of relationship.
- Mike emphasized that the elected officials want all of the waste haulers at the table, especially those that operate within EWA's service area.
- Adam reviewed the draft Waste Hauler Agenda, which would cover background on the plant, current operation, and a discussion of potential capacity.
- Scott M stated that he would like to have an agenda finalized and sent out to each waste hauler 30 days in advance of the meeting, to give them adequate prep time.
  - **ACTION: Adam to send a draft agenda of the Waste Haulers meeting to EWA and finalize per any EWA comments 30-days in advance of the meeting.**
- Adam stated that another discussion point for the meeting is the waste haulers potential interest in accepting compressed natural gas (CNG). Scott M stated that SDG&E should be involved in these conversations as well. A meeting should be arranged with SDG&E.
  - **ACTION: Octavio to send EWA's SDG&E point of contact to Adam.**
- Different gas delivery options, tube trailer vs. pipeline, were discussed. Adam stated that a tube trailer has less stringent standards than a pipeline, but there would be tube trucks coming in and out of the facility. However, the pipeline would have more stringent sampling/reporting requirements and the investment for an interconnection for the pipeline could cost $1 – 2 million dollars. This will be developed as the alternatives analysis is advanced.

<u>Other Outstanding Items</u>

BC reviewed their understanding of the discussion with Anaergia:

- Adam stated that Anaergia is promoting Omnivore as a process treatment option, which may or may not be the right fit at EWA. However, there might be opportunity for Anaergia to work with waste haulers for pre-processing food waste.

<u>Review of Mass Balance and Project Flows and Loads</u>

BC presented the project flows and loads:

- Mass Balance
  - Hari reviewed the assumptions made to calculated WAS. Octavio responded that the actual WAS flow is around 0.75 MGD, and that he could send that data to BC (ACTION above).
  - Adam stated that the VSR value of 65% seemed suspiciously high. Octavio stated that EWA's VSR value was closer to 55%.
  - Hari stated that the centrifuge % capture right now is 78%. Octavio responded that the capture rate for the centrifuges is consistently 95%, and that the calculated value is probably lower because of values during start-up and shut-down.
    - **ACTION: Octavio to send Hari lab data on the performance of the centrifuges.**

  - Tom requested that the BC team review the data with Octavio after he send is to BC.
    - **ACTION: Tom to send up conference call with Octavio after reviewing the data.**
- Solids Mass Balance Comparison
  - Tom presented a graph that shows that BC's calculated solids loading was higher than the calculated values in the Process Master Plan (2016).
  - Octavio stated that one reason for the increase might be a 2015 change in how EWA sampled the influent flow.
  - **ACTION: Tom to work with Octavio on refining the solids mass balance.**
- Power Loads and Gas Usage
  - Adam reviewed the gas usage graphs with EWA.
  - Digester Gas Usage Summary – Total gas production is trending up, probably due to the increase in high strength waste deliveries. Adam pointed out that the yellow "Total Gas Production" line didn't match up with the top of the bars, which is normal. Scott M pointed out that the important part is that the yellow line followed the same trend as the bars.
  - Natural Gas Usage Summary - Most of the natural gas is being used for the heat dryer and cogen, which is expected.
  - Power Production and Import – Currently, EWA is making about 80% of their electricity needs. This means that EWA could potentially export power. A look into the SDG&E power bills also showed that the actual kWh power that EWA is purchasing only constitutes $10,000 out of a $70,000 bill. The majority of the bill is non-coincident and standby power.
    - Mike stated that he had talked to SDG&E about the standby charges and haven't been able to get around them.
- Engine Fuel Use
  - Octavio explained that the increase in natural gas in November 2015 was because they needed to switch to natural gas to stay below emission limits.

<u>Screening of Technologies</u>

BC the fatal flaw filter and evaluation criteria, and then evaluated each process technology against that criteria. The results of the evaluation are summarized below and more details are included in the attached Workshop #2 PowerPoint slides.

- There were four fatal flaw filters:
  - At least one successful North American installation of the technology
  - At least one successful installation in a facility of similar size
  - There is available space to implement that technology
  - Compatibility with plant size and any existing equipment
- The technologies that passed the fatal flaw filter were then scored for each evaluation criteria, which included: end use market compatibility, proven technology performance, life cycle costs, energy/resource recovery, O&M impacts, environmental impacts, community and stakeholder impacts, and project site combability.
  - Each evaluation criteria was then weighted to reflect EWA's priorities.

  - Technologies that scored lower than a 3 were eliminated, and technologies that scored greater than a 3 would be evaluated through the SWEET model.
  - O&M impacts criteria will be clarified to describe reduction in O&M staff time.
- Thickening Technologies
  - Prior planning efforts recommended evaluating rotary drum thickeners (RDTs) against the existing primary clarifier and dissolved air flotation thickeners (DAFTs). EWA concurred with that recommendation.
  - Natalie asked if the team should add Anaergia's Omnivore to the list of technologies to evaluate. Scott L proposed that that decision to be made after a meeting with Anaergia takes place.
    - **DECISION: BC team to evaluate RDTs against the current status quo of primary clarifier and DAFT.**
- Stabilization Technologies
  - Technologies that failed the fatal filter: Staged Digestion, Acid/Gas Phased Digestion, Temperature Phased Anaerobic Digesion, Enzymatic Hydrolysis, Chemical Hydrolysis, THP – DLD, and Solid Stream CAMBI.
  - Technologies that scored lower than a 3 in the evaluation criteria: Lystek.
  - **(DECISION) Stabilization technologies that moved to the next round of evaluation: Mesophilic Digestion, Mesophilic Digestion with High Solids, Thermophilic Digestion, and Traditional CAMBI.**
- Dewatering Technologies
  - Technologies that failed the fatal filter: Bucher Press.
  - Technologies that scored lower than a 3 in the evaluation criteria: Screw Press, Rotary Press, and Volute Press.
  - **(DECISION) Dewatering technologies that moved to the next round of evaluation: Centrifuges and Belt Press.**
- Post-Dewatering Technologies
  - Technologies that failed the fatal filter: Thermal Drying: Low Quality (Indirect Dryer), Gasification, and Pyrolysis.
  - Technologies that scored lower than a 3 in the evaluation criteria: N/A
  - **(DECISION) Post-dewatering technologies that moved to the next round of evaluation: Thermal Drying: High Quality (Drum Dryer).**
- Alternative Power Production Technologies
  - Technologies that failed the fatal filter: Fuel Cells and Wind Turbines.
  - Technologies that scored lower than a 3 in the evaluation criteria: Energy Storage (Batteries), Large Scale Solar Photovoltaics
  - **(DECISION) Alternative power production technologies that moved to the next round of evaluation: Internal Combustion Engines (Status Quo), Internal Combustion Engines – with Gas Conditioning, Internal Combustion Engines – with Exhaust Treatment, Digester Upgrading – Pipeline Injection, Micro-Turbines, Biosolids Drying – Direct Use of Biogas, Large-Scale Solar Photovoltaics (PV), and Small Scale Rooftop PV.**
- Waste Heat Technologies
  - Technologies that failed the fatal filter: Absorption and Adsorption Chillers, Organic Rankine Cycle, and Gasification of Biosolids.

- Technologies that scored lower than a 3 in the evaluation criteria: N/A
- **(DECISION) Waste heat technologies that moved to the next round of evaluation: Small-Scale Steam Turbines, and Thermo/THP.**

<u>**Creation of End to End Alternatives**</u>
The BC team reviewed initial alternatives that were to be evaluated, as well as different power production alternatives. The power production alternatives included:

- Baseline: existing cogen and drying
- Baseline with gas conditioning
- Existing cogen with vehicle fuel (via pipeline injection or tube trailer)
- Existing cogen with microtubines
- Existing cogen with steam boiler/turbine
- New cogen permit, CO catalyst and selective catalytic reduction (SCR), with gas conditioning
- Vehicle fuel (primary use of digestive gas) with existing cogen
- **ACTION: Adam to present a big picture view of the power production alternatives at the next workshop.**

<u>**Grant Updates**</u>
BC provided an overview of different grant programs, and explained how the program would fit into the SWEET model. The programs included:

- Self-Generation Incentives Program
- Low Carbon Fuel Standard
- Renewable Fuel Standard
- Organics Grant Program
- Healthy Soils Program
- Green Project Reserve

<u>**Air Permitting Discussion**</u>
BC and EWA discussed the current efforts of the air permit modification. EWA is submitting a request for permit modification in one week. If successful, it would increase the permitted cogen capacity by ~20%.

<u>**Look Ahead & Wrap-Up**</u>
The meeting ended with a look ahead and reviewing pending action items.

- Workshop #3 will take place in mid-September, and the team will try to schedule the Waste Hauler Meeting on the same day.
- The team will present the following in Workshop #3:
  - Baseline SWEET model
  - Conceptual layouts and details of alternatives for consensus and feedback
  - Air permitting impacts on power production alternatives
  - Grant updates
- WEFTEC is also taking place in early-October. Mike stated that it would be beneficial to walk the floor together with BC to look at potential technologies.
  - **ACTION: BC to identify technologies that would be beneficial to visit at WEFTEC.**

- ACTION: BC to check in with EWA to confirm is any support is needed related to the next board meeting on Oct 11.

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Energy & Emissions Strategic Plan & Biosolids Management Plan Update

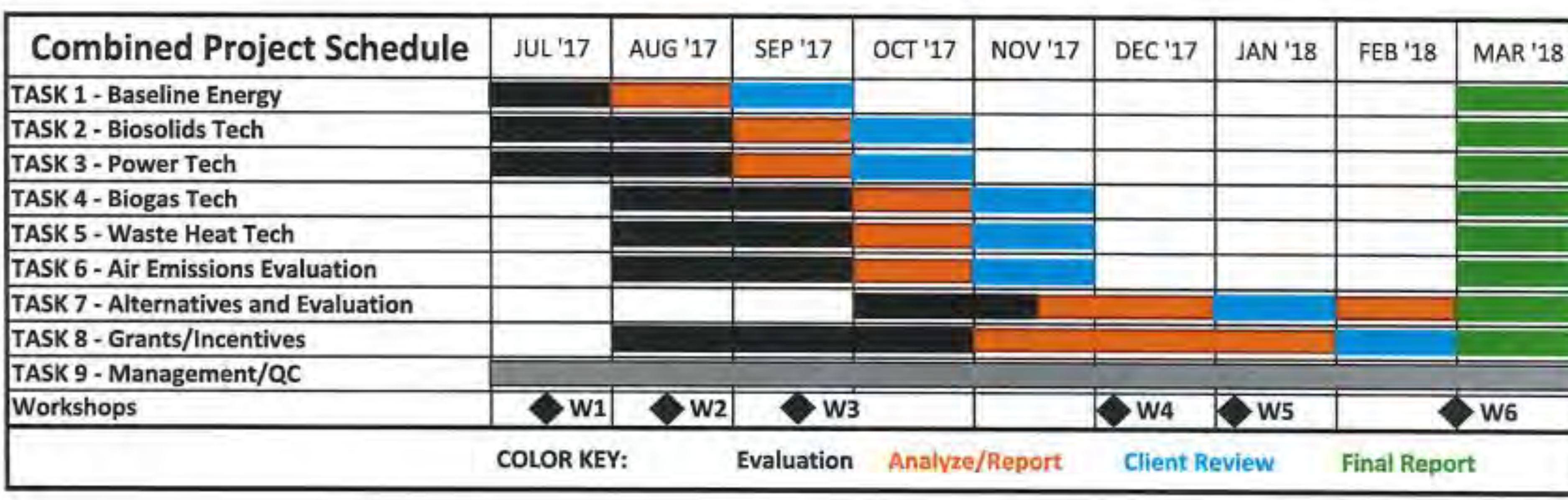
ENCINA WASTEWATER AUTHORITY

Workshop #2 – August 16, 2017

Encina Water Pollution Control Facility

Project Schedule

- Progress On Schedule
- Task 1 Energy Baseline Complete
- Other Tasks (except 7) are Under Way
- Workshop #2 Today



Agenda

- Administrative (20 min)
  - Status of data requests
  - Comments on waste hauler agenda
  - Discussion with Anaergia
- Review Mass Balance and Projected Flows and Loads (45 min)
- Review Fatal Flaw and Screening Criteria (30 min)
- Screen Technologies (1 hr)
- Discussion of Preliminary End to End Alternatives (30 minutes)
- Grants Update (10 min)
- Air Emissions Review (5 min)
- Wrap-Up/Review Action Items (10 min)

New Data Requests

- Trussell food waste capacity report
- O+M costs for the engines (have costs for electricity for the system, but not for gas treatment, upkeep, general maintenance, etc.)
- WAS daily flow data (back-calculated for mass balance)
- FOG TS and VS data (used assumptions from 2016 PMP for mass balance)
- Any air permitting summaries or progress between EWA and Don King

Outstanding Data Requests

- Cogen and solids systems drawings, engine cut sheets
- Dryer system drawings and cut sheets
- Recent air permitting efforts – progress, memos, contact info
- Copies of current air permits (SDAPCD and Title V)
- Energy Management – typical day operating procedure:
  - Cogen strategy
  - Peak period disconnect from utility
  - HSW storage and feed strategy

Waste Hauler Agenda

- Timing: September (coordinate with Workshop 3)
- Attendees:
  - EWA – Scott, Jimmy
  - BC – Adam, Ari
  - WM
  - Republic
  - EDCO
  - LES?
  - Anaergia?
- Goals:
  - Provide background info to haulers about EWA's goals and BEE effort
  - Determine availability of pre-processed food waste, market demand for an EWA initiative to receive more material, tipping fee range for SWEET analysis
  - Gauge interest in a renewable CNG partnership
  - Discuss "next steps" such as letter of intent, future coordination

Other Outstanding Items

- Discussion with Anaergia
  - Omnivore as an alternative
  - Orex or Biorex for food waste pre-processing
  - Status of food waste receiving project(s) with Republic
  - Capacity at Rialto facility for dried product?

Review of Mass Balance and Projected Flows and Loads

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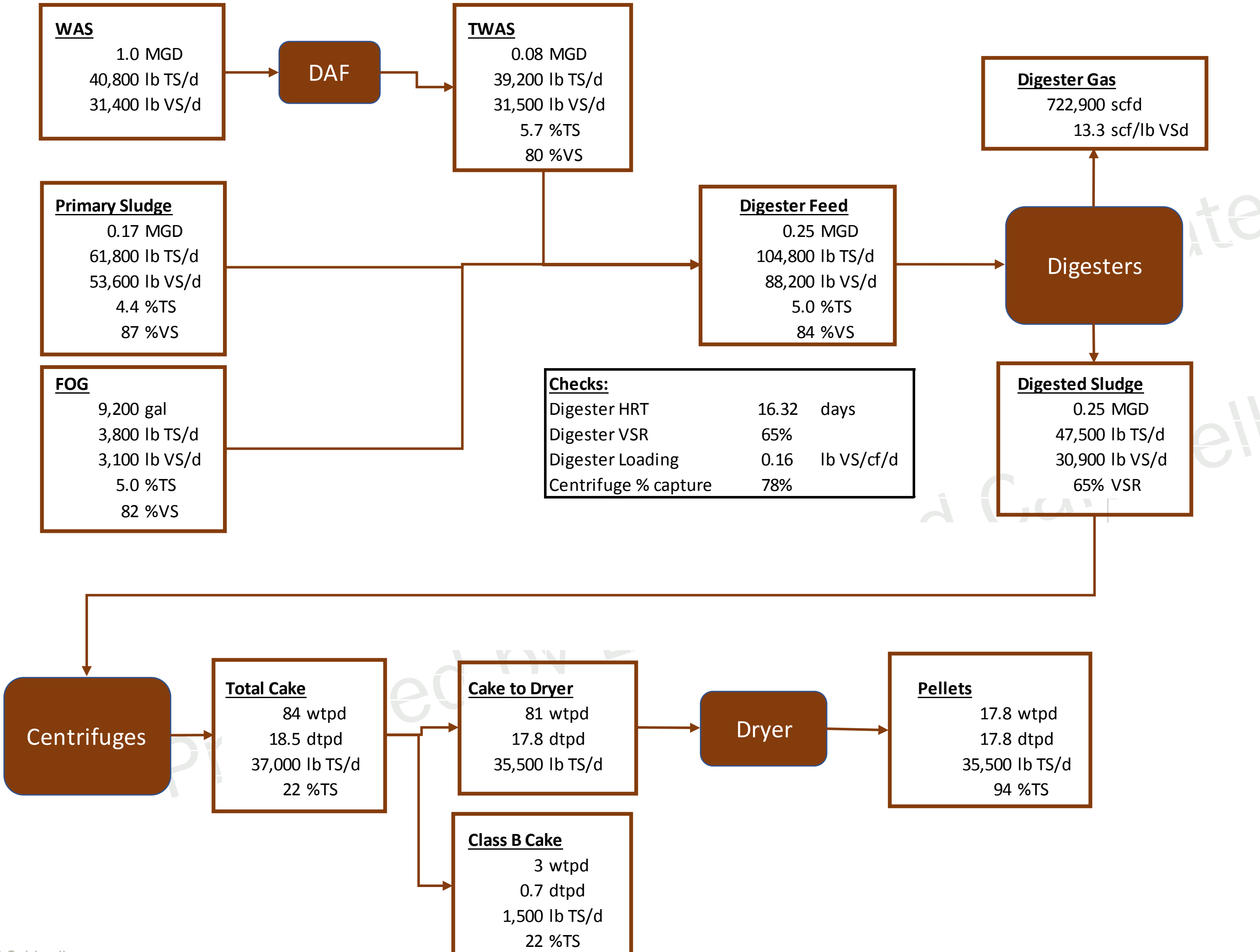
Mass Balance

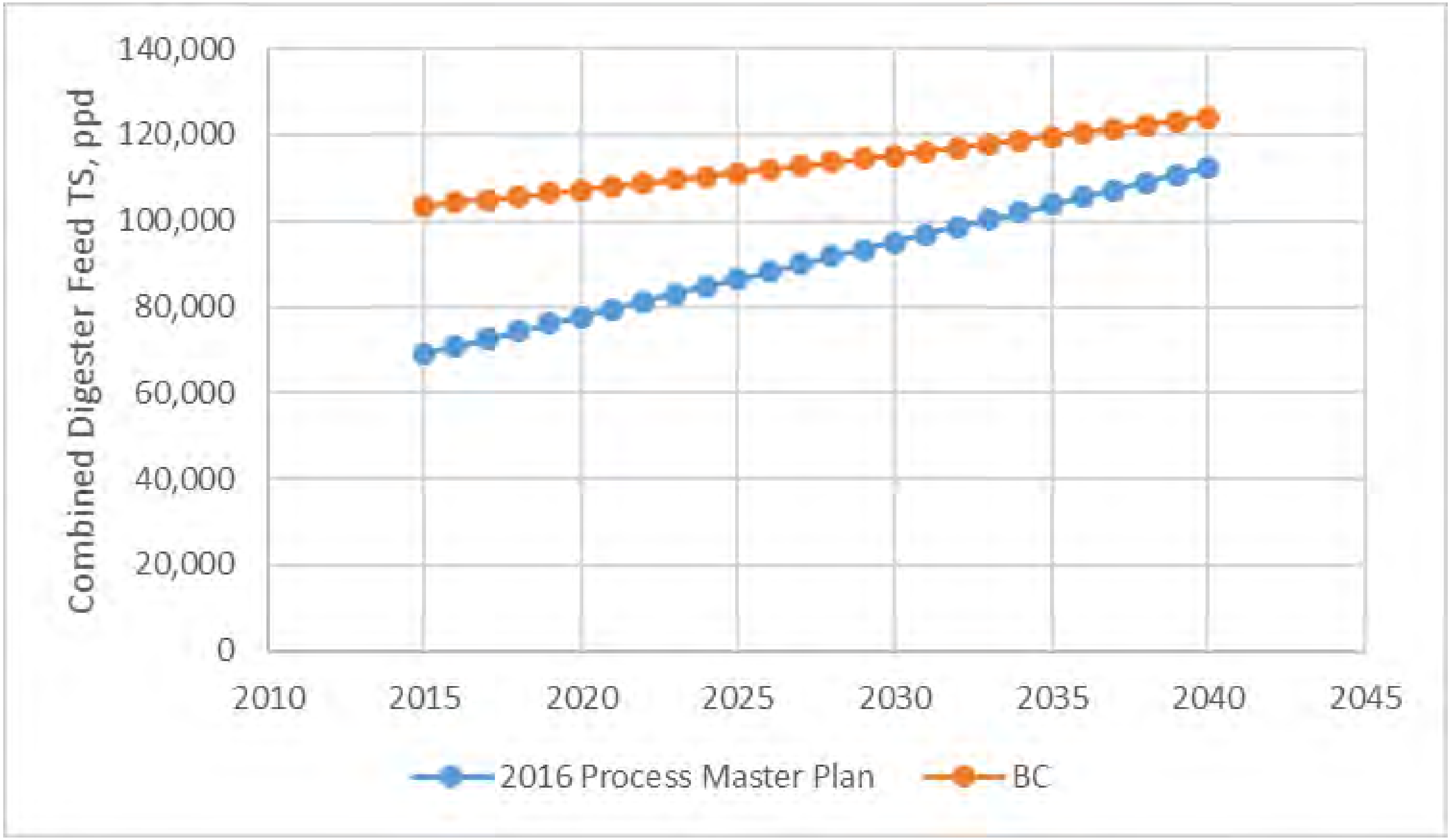
MAY 2015 - JUNE 2017



Mass Balance Assumptions

- TWAS flows that were zero and subsequent loads when TWAS flow was zero were excluded. Assumed percent capture rate for the DAFTs is 95%.
- TWAS flows were taken from DAFT totalizer data and digester feed meters.
- The digester feed flow from July 1, 2016 to June 2017 were subtracted daily to obtain a daily digester feed volume. This was based on the assumption that the flow values were cumulative from a meter reading starting 7/1/16.
- The Class B cake data were averaged with zero data to obtain an annualized daily average.
- FOG data were a daily average of the volumes received. This assumes FOG is fed 24/7/365. Assumes %TS and %VS are 5% and 82%, respectively.
- To calibrate the mass balance as shown, 2,300 lbs TS/d and 1,900 lbs VS/d were added to Primary Sludge.

Solids Mass Balance Comparison



Sludge Production Peaking Factors

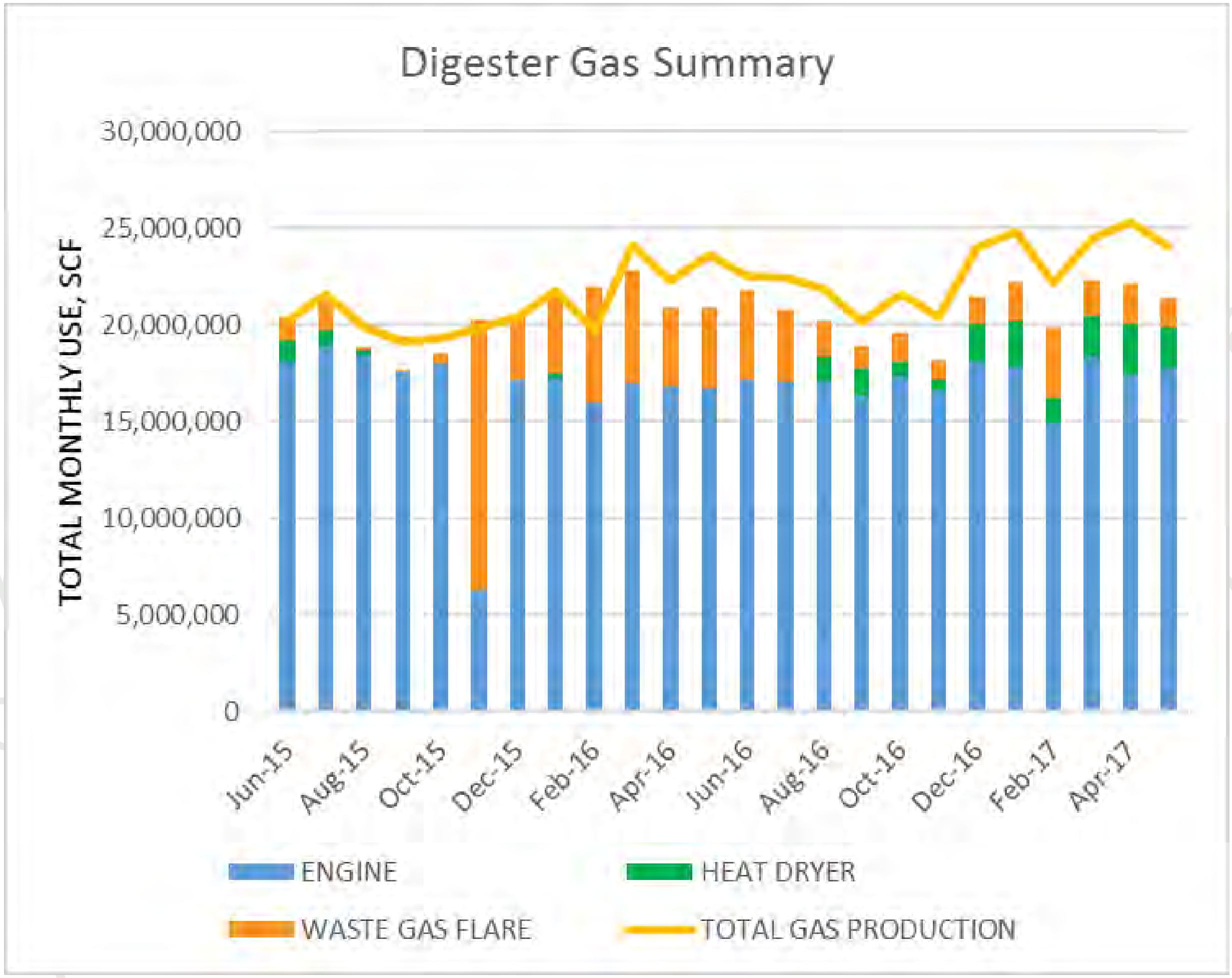
	Max Month	Peak 2-Week	Peak Week	Peak Day
Primary Sludge	1.23	1.3	1.4	1.60
WAS	1.23	1.3	1.4	1.60
Combined Sludge	1.23	1.3	1.4	1.60

Notes:
- Peaking factors for maximum month and peak day conditions are developed based on 2016 PMP solids projections.
- Peaking factors for maximum 2-week and maximum week conditions are proposed based on historical data.

Power Loads and Gas Usage

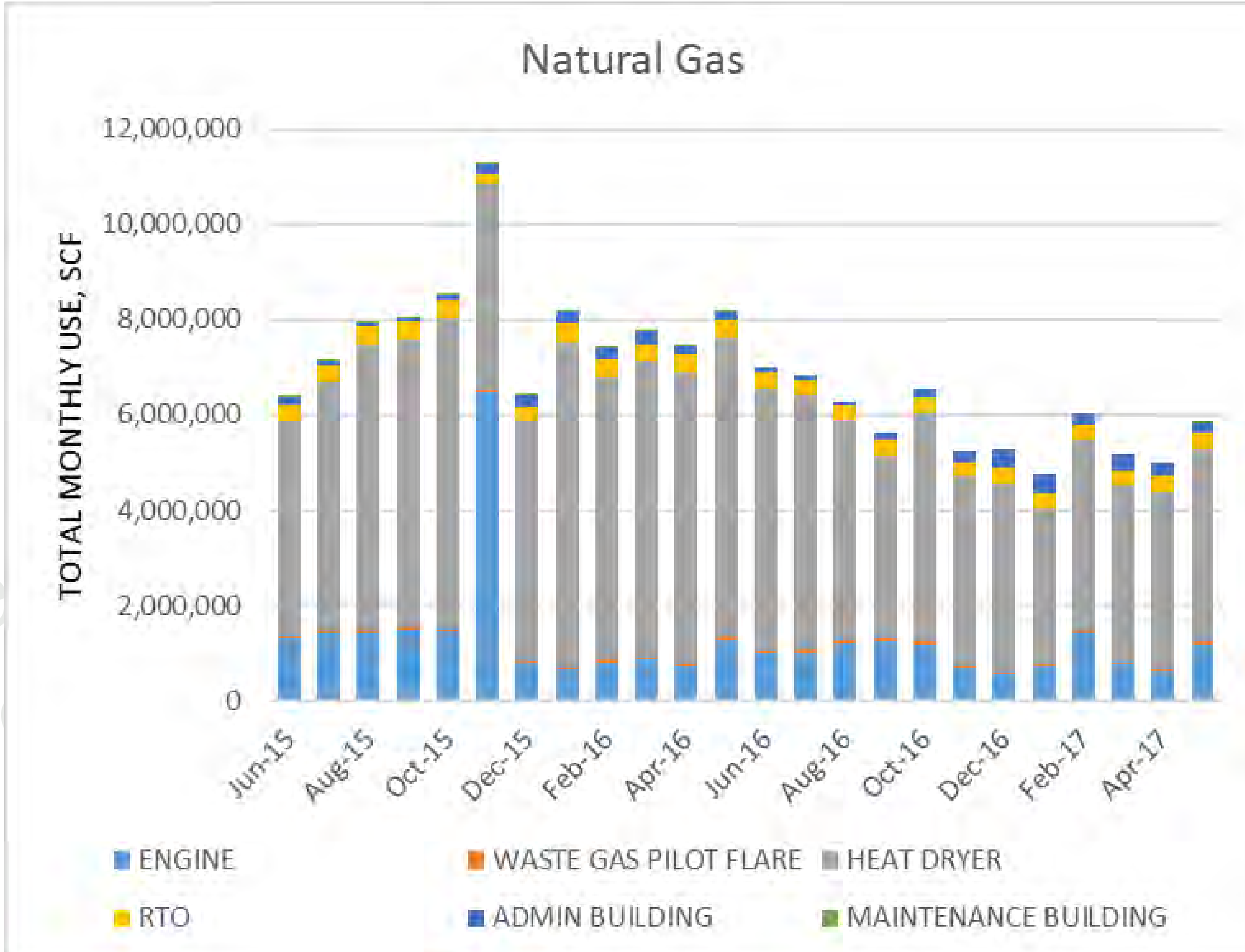
- Power:
  - Monthly production: 1,500 kW (2, 750 kW engines full output – 80% of total electrical demand)
  - Monthly import: 385 kW equivalent (1,390 MWh per year)
- Digester gas:
  - Average production: 1,645,000 therms per year
  - Engines: 1,263,000 therms per year
  - Waste gas: 229,000 therms per year
  - Heat dryer: 57,000 therms per year
- Natural gas: 856,000 therms per year
  - Engines: 156,000 therms/year
  - Other plant use: 700,000 therms/year

Digester Gas Usage Summary – Last 2 years



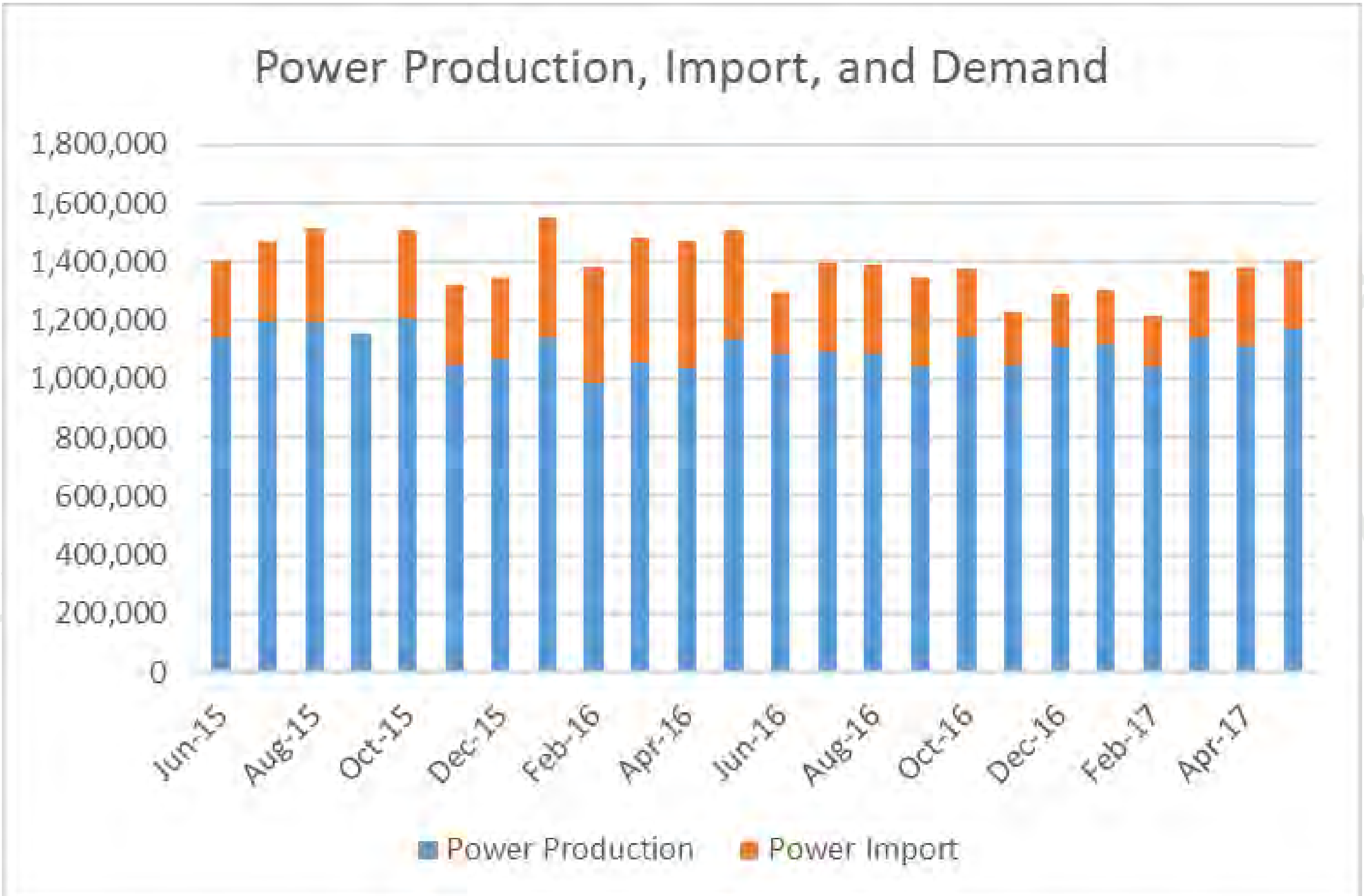
1) What happened November 2015? DG outage?
2) Divergence of "total gas production" from sum of other meters
3) When DG is sent to the heat dryer, what contributes to flaring?
4) Flared gas, over the course of the last year, represents 179 kW of "potential" power production

Natural Gas Usage Summary – Last 2 years



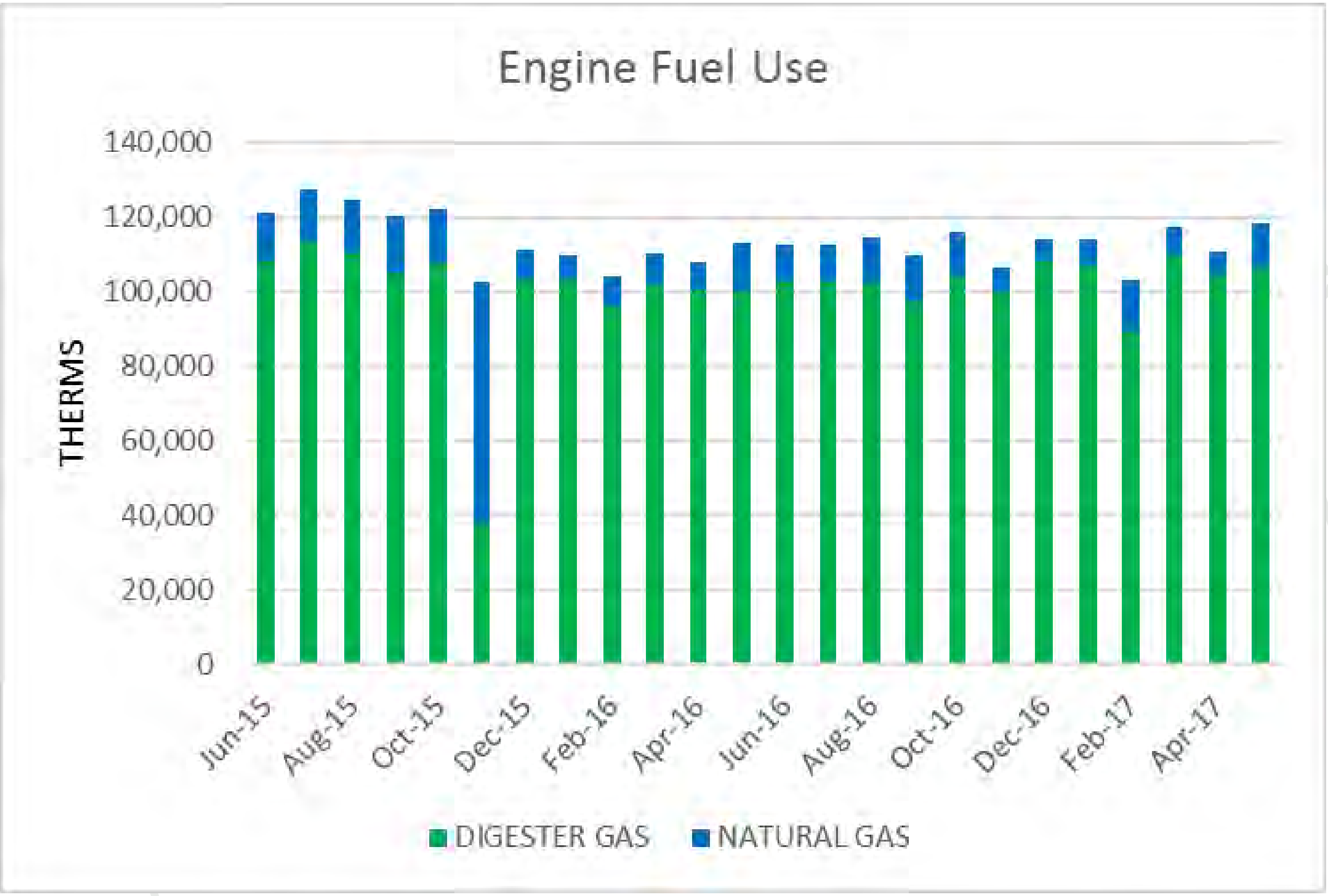
1) What is the NG control strategy to cogen? Why is there NG contribution to cogen in months where DG is being sent to dryer or flare?

Power Production and Import – Last 2 years



1) Consistently operating at 2-engine output
2) Operating a third engine at full output (if DG production increases and/or permit is modified) would result in power export

Engine Fuel Use– Last 2 years



1) Consistent operation
2) What is NG blending strategy?

Screening of Technologies

Fatal Flaw Filter

- Applied uniformly across all technologies
- Four criteria:
  - At least one successful North American installation of technology
  - At least one successful installation in a facility of similar size
  - Available space
  - Compatibility with plant size and any existing equipment

Evaluation Criteria

Criterion	Criterion Description	Scoring Description
End Use Market Compatibility	• Onsite technology directly produces one of the recommended product alternatives. • Alternately, onsite technology product is compatible with product alternatives.	• **Low score** indicates technology product that has not been identified as part of the product list nor compatible with the product list. **High score** indicates technology product that is compatible with Class B cake, Class A cake, Class A THP cake, and dried Class A pellet.
Proven Technology Performance	• Proven and reliable technology with same configuration intended at Encina. • Long successful operating track record.	• **Low score** indicates no successful large scale operating installations in North America or Europe, no successful demonstration scale installations in North America or Europe, and unknown safety or reliability record. • **High score** indicates more than one successful operating installation in North America or Europe, more than one operating installation at a WWTP of at least 40 mgd in North America or Europe, track record duration > 5 years, and vendors in Western USA.
Minimize Life Cycle Costs	• Qualitative metric of program cost. • Capital and O&M costs based on existing Encina data or similar experience at other WWTPs. • Potential revenues from sales. • Product/market geographic proximity.	• **Low score** indicates high capital cost to build onsite facilities, high O&M costs, expensive end use market, and high transportation costs. • **High score** indicates low capital cost to build onsite facilities, low O&M costs, potential product revenue, and product destination within 100 miles.

Evaluation Criteria (cont.)

Criterion	Criterion Description	Scoring Description
Energy/Resource Recovery	• Increases biogas production through advanced digestion. • Supports co-digestion of organic waste. • Recovery of renewable energy. • Beneficial use of biosolids product.	• **Low score** indicates high energy requirement for onsite technology, no increase in biogas production, technology does not recover energy as biogas, no recovery of renewable energy in biosolids, and no biosolids resource recovery. • **High score** indicates a higher biogas production, compatible with co-digestion of organic waste, and biosolids resource recovery.
O&M Impacts	• Impacts to existing plant O&M staff levels. • Complexity of new technology O&M and control systems. • Reliability of new technology (potential downtime). • Minimal impacts to plant safety.	• **Low score** indicates more O&M time required, complex mechanical and control systems required compared with existing plant facilities, potential equipment downtime, and new chemicals or hazards. • **High score** indicates reduction in O&M staff time required, new technology is simple to operate and maintain, reliable with minimal downtime, and no new chemicals or hazards.

Evaluation Criteria (cont.)

Criterion	Criterion Description	Scoring Description
Environmental Impacts	• Impacts to carbon footprint and air permitting.	• **Low score** indicates high carbon footprint for technology, high travel distance to end use, difficult to treat side-streams or impacts to GWRS, and new permitting for environmental regulatory requirements. • **High score** indicates low carbon footprint for technology, low travel distance to end use, minimal side-stream generation or impacts, no additional permitting for environmental regulatory requirements.
Community & Stakeholder Impacts	• Minimize nuisance impacts such as dust, odors, vectors, aesthetics, noise and traffic. • Assess impacts to partner agency issues/values as well as local planning codes and requirements.	• **Low score** indicates nuisance factors for onsite technology are difficult to mitigate. • **High score** indicates nuisance factors can be mitigated at plant site.
Project Site Compatibility	• Assess compatibility of technology with available plant footprint. • Incorporation into existing treatment process. • Ability to accept co-digestion substrates.	• **Low score** indicates lack of site space for new facilities, requires abandonment of existing facilities, and difficult integration with existing plant. • **High score** indicates available footprint for new facilities and maintains space for future facilities, easy of integration with existing processes and facilities.

Evaluation Criteria Weighting

Criterion	Weight Stabilization	Weight Dewatering	Weight Biogas Use and Waste Heat
End Use Market Compatibility	15%	15%	NA
Proven Technology Performance	15%	25%	20%
Minimize Life Cycle Costs	10%	20%	10%
Energy/Resource Recovery	20%	NA	25%
O&M Impacts	10%	15%	10%
Environmental Impacts	10%	5%	15%
Community & Stakeholder Impacts	10%	5%	10%
Project Site Compatibility	10%	15%	10%

Thickening Technologies

- Primary Clarifier (Existing)
- DAFT (Existing)
- Rotary Drum Thickener (RDT)
- Recommendation from prior planning efforts used to evaluate RDTs compared to status quo

Starting with the End in Mind – Market Compatibility

- Class B Cake – Land application (Arizona) or contract composting
- Class A Cake – Land application in CA and AZ (soil blending and land reclamation possible)
- Class A THP Cake – Land application and soil blending (land reclamation possible)
- Class A granules (high quality) – Land application, horticulture, fertilizer blending, soil blending (land reclamation possible)
- Class A granules (low quality) – Land application (land reclamation possible)
- Class A Lystegro – Land application

Options to produce end-use product alternatives

Product Alternatives	Technology Options
Class B Cake	Class B digestion
Class A Cake	Class A digestion (thermophilic or TPAD)
Class A THP Cake	THP/digestion
Class A Dried Granule (high quality)	Class A or B digestion + two dryer trains
Class A Dried Granule (low quality)	Class A or B digestion + maximize existing dryer
Class A Lystegro	Class A or B digestion + Lystek

Stabilization Technologies

- Mesophilic Digestion
- Mesophilic High Solids Digestion
- Staged Digestion
- Acid/Gas Digestion
- Thermophilic Digestion
- Temperature Phased Anaerobic Digestion (TPAD)
- Enzymatic Hydrolysis
- Chemical Hydrolysis
- Lystek
- Thermal Hydrolysis Process (THP) – Traditional CAMBI
- THP – Digestion-Lysis-Digestion (DLD)
- THP – Solid Stream CAMBI

Stabilization Technologies – Fatal Flaw

	Technology Maturity	Successful Operation of Comparable Size	Available Space	Compatibility
Mesophilic Digestion	Pass	Pass	Pass	Pass
Mesophilic with High Solids	Pass	Pass	Pass	Pass
Staged Digestion	Pass	Pass	Fail	Pass
Acid/Gas Phased Digestion	Pass	Pass	Fail	Pass
Thermophilic Digestion	Pass	Pass	Pass	Pass
Temperature Phased Anaerobic Digestion	Pass	Pass	Fail	Pass
Enzymatic Hydrolysis	Fail	Fail	Pass	Pass
Chemical Hydrolysis	Pass	Fail	Pass	Pass
Lystek	Pass	Pass	Pass	Pass
Traditional CAMBI	Pass	Pass	Pass	Pass
THP - DLD	Fail	Fail	Fail	Pass
Solid Stream CAMBI	Fail	Fail	Pass	Pass

Stabilization Technologies - Screening

	Mesophilic Digestion	Mesophilic Digestion with High Solids	Thermophilic Digestion	Lystek	Traditional CAMBI
End Use Market Compatibility	3	3	3	2	5
Proven Technology Performance	5	2	5	2	4
Minimize Life Cycle Costs	3	3	4	2	2
Energy/Resource Recovery	3	4	5	3	4
O&M Impacts	4	3	4	3	3
Environmental Impacts	4	4	4	3	4
Community & Stakeholder Impacts	4	4	4	2	4
Project Site Compatibility	5	3	5	3	2
Weighted Score	**3.80**	**3.25**	**4.30**	**2.50**	**3.65**

Dewatering Technologies

- Centrifuge
- Belt press
- Screw press
- Rotary press
- Volute press
- Bucher press

Dewatering Technologies – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Centrifuges	Pass	Pass	Pass	Pass
Belt Press	Pass	Pass	Pass	Pass
Screw Press	Pass	Pass	Pass	Pass
Rotary Press	Pass	Pass	Pass	Pass
Volute Press	Pass	Pass	Pass	Pass
Bucher Press	Fail	Fail	Pass	Pass

Dewatering Technologies - Screening

	Centrifuges	Belt Press	Screw Press	Rotary Press	Volute Press
End Use Market Compatibility	3	5	4	3	3
Proven Technology Performance	5	5	3	2	2
Minimize Life Cycle Costs	4	4	3	3	3
O&M Impacts	5	5	2	2	2
Environmental Impacts	3	2	3	3	3
Community & Stakeholder Impacts	4	4	4	4	4
Project Site Compatibility	5	4	2	3	3
Weighted Score	**4.35**	**4.45**	**2.90**	**2.65**	**2.65**

Post-Dewatering Technologies

- Thermal drying – high quality granules
- Thermal drying – low quality granules (indirect dryer)
- Gasification
- Pyrolysis
- Partial solar drying
- Deep well injection
- Dehydration
- Incineration

Post-Dewatering Technologies – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Thermal Drying: Low Quality (Indirect Dryer)	Pass	Pass	Pass	Fail
Thermal Drying: High Quality (Drum Dryer)	Pass	Pass	Pass	Pass
Gasification	Fail	Fail	Pass	Pass
Pyrolysis	Fail	Fail	Pass	Pass

Alternative Power Production Technologies

- Internal Combustion Engines
- Digester gas upgrading
  - For pipeline injection
  - For vehicle fueling (CNG)
- Microturbines
- Biosolids Drying – direct use of biogas
- Energy Storage (Batteries)
- Fuel Cells
- Large Scale Solar Photovoltaics (PV)
- Small Scale/Rooftop Solar Photovoltaics
- Wind Turbines
- Direct sale to adjacent power plant

Alternative Power Production – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Internal Combustion Engines	Pass	Pass	Pass	Pass
Digester Upgrading: Pipeline Injection	Pass	Pass	Pass	Pass
Digester Upgrading: Vehicle Fueling (CNG)	Pass	Pass	Pass	Pass
Microturbines	Pass	Pass	Pass	Pass
Biosolids Drying - Direct Use Of Biogas	Pass	Pass	Pass	Pass
Energy Storage	Pass	Pass	Pass	Pass
Fuel Cells	Fail	Fail	Pass	Pass
Large Scale Solar Photovoltaics	Pass	Pass	Pass	Pass
Small Scale/Rooftop Solar Photovoltaics	Pass	Pass	Pass	Pass
Wind Turbines	Pass	Pass	Fail	Fail

Alternative Power Production – Screening

	Internal Combustion Engines - Status Quo	Internal Combustion Engines - With Gas Conditioning	Internal Combustion Engines - With Exhaust Treatment	Digester Upgrading: Pipeline Injection	Digester Upgrading: Vehicle Fueling (CNG)	Micro-turbines	Biosolids Drying - Direct Use Of Biogas	Energy Storage (Batteries)	Small Scale Rooftop PV	Large Scale Photovoltaics
Proven Technology Performance	5	5	4	2	3	4	5	3	5	5
Minimize Life Cycle Costs	3	3	4	4	4	3	3	3	4	4
Energy/Resource Recovery	4	4	5	4	4	4	2	1	5	5
O&M Impacts	3	4	3	4	4	4	3	4	5	5
Environmental Impacts	3	3	4	5	5	5	3	3	5	4
Community & Stakeholder Impacts	4	4	5	5	5	4	3	3	5	5
Project Site Compatibility	5	5	4	4	4	4	5	3	2	2
Weighted Score	3.95	4.05	4.25	3.85	4.05	4.05	3.35	2.60	4.60	4.45

Waste Heat Technologies

- Small Scale Steam Turbines
- Thermo/THP
- Absorption and Adsorption Chillers
- Organic Rankine Cycle (ORC)
- Gasification of Biosolids

Waste Heat Technologies – Fatal Flaw

	Technology Maturity	Successful Operation	Available Space	Compatibility
Small Scale Steam Turbines	Pass	Pass	Pass	Pass
Use For Thermo/THP	Pass	Pass	Pass	Pass
Absorption And Adsorption Chillers	Pass	Pass	Pass	Fail
Organic Rankine Cycle	Fail	Fail	Pass	Pass
Gasification Of Biosolids	Fail	Fail	Pass	Pass

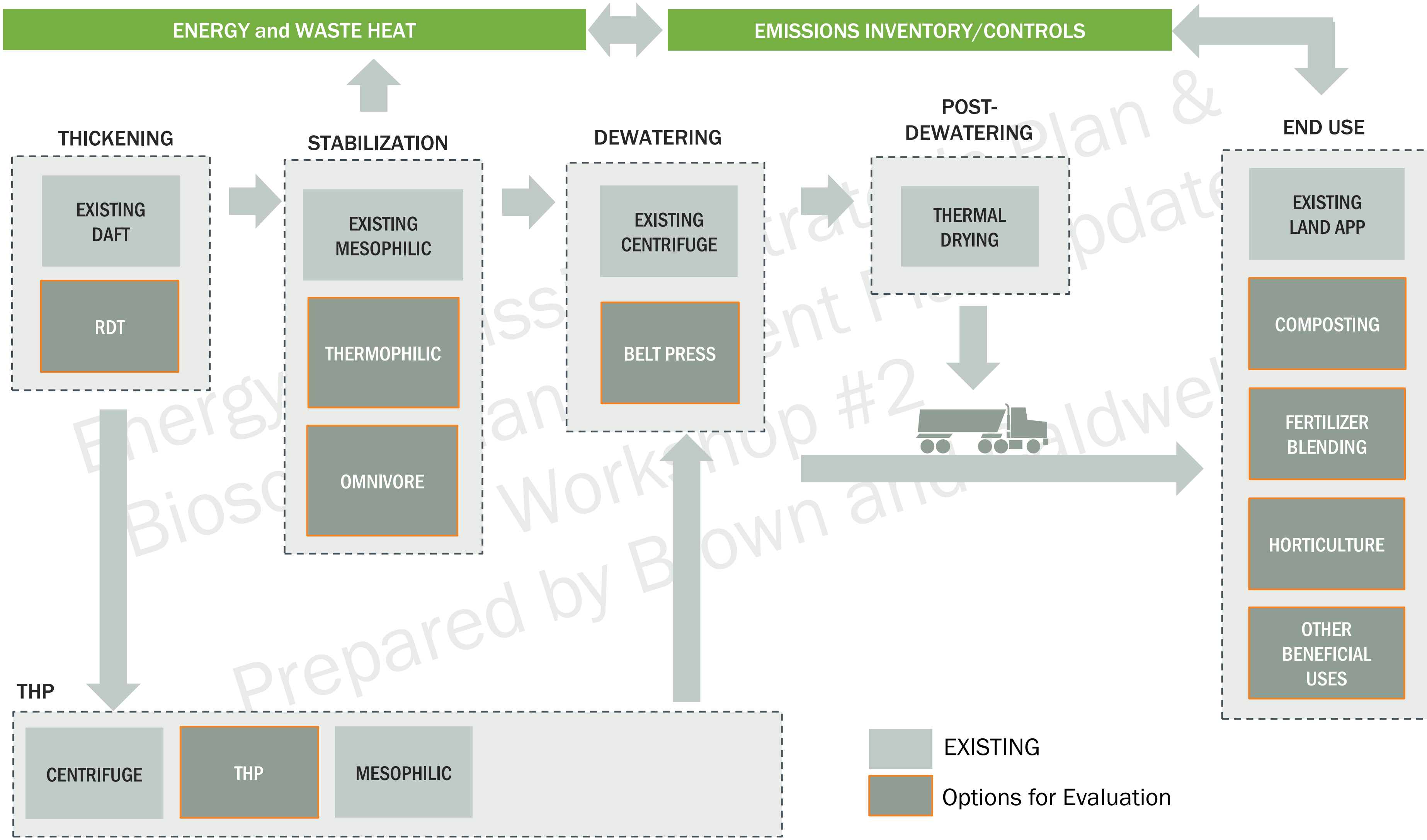
Waste Heat Technologies – Screening

	Small-Scale Steam Turbines	Thermo/THP
Proven Technology Performance	2	5
Minimize Life Cycle Costs	3	5
Energy/Resource Recovery	4	4
O&M Impacts	3	3
Environmental Impacts	3	4
Community & Stakeholder Impacts	3	4
Project Site Compatibility	3	4
Weighted Score	**3.05**	**4.2**

Creation of End to End Alternatives

Brown AND Caldwell

Evaluating Technologies and Markets Together



Initial Alternatives

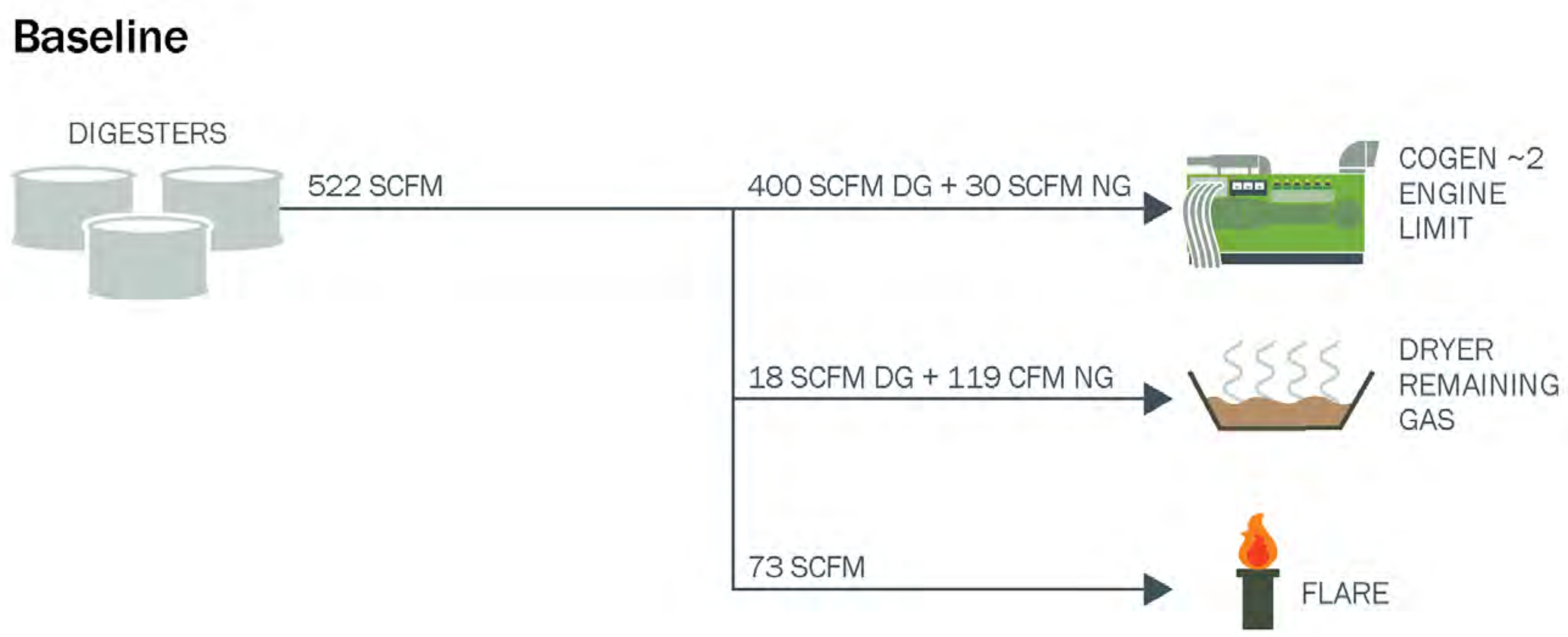
- Meso plus second dryer
- Meso plus Class B hauling
- Thermophilic
  - With and without second dryer
- Cambi (traditional)
  - With and without second dryer

- Additional Layers
  - Thickening
  - Dewatering
  - Energy alternatives
  - End use markets

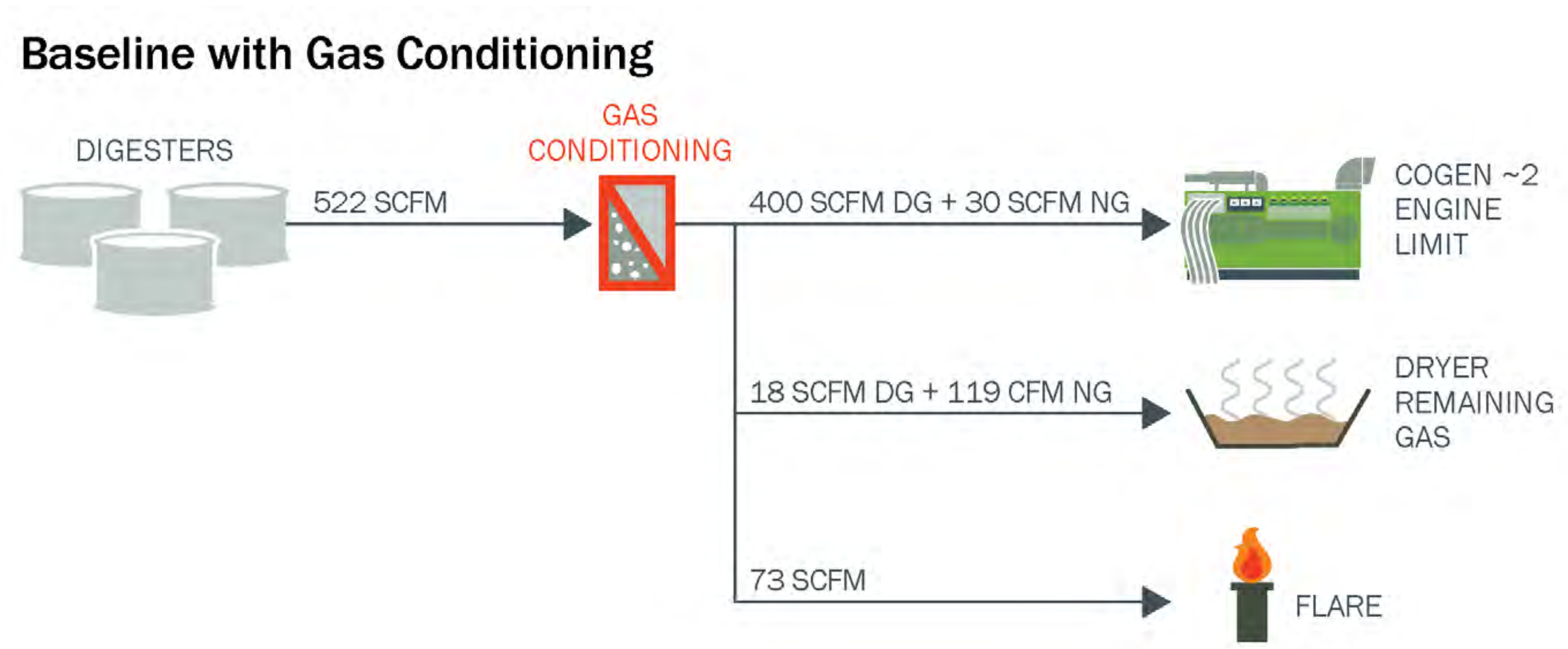
Alternatives: Power Production

- Baseline: Existing cogen + drying
- Baseline + gas conditioning
  - Gas conditioning serves to reduce O&M costs associated with engines and dryer
- Existing cogen + vehicle fuel (via pipeline injection or tube trailer)
  - No permit modification to cogen / no DG to dryer
  - Continue to operate two engines
  - Additional gas routed to vehicle fuel
- Existing cogen + microturbines
  - Includes gas conditioning
  - No permit modification to cogen / no DG to dryer
- Existing cogen + steam boiler/turbine
  - No permit modification to cogen / no DG to dryer
  - Additional gas routed to steam boiler; steam used in small turbine
- New cogen permit, CO catalyst and SCR, gas conditioning
  - Need to consider plant demand as a limit on power production
- Vehicle Fuel (primary use of DG) + existing cogen (natural gas + tail gas)
  - "All in" on vehicle fuel

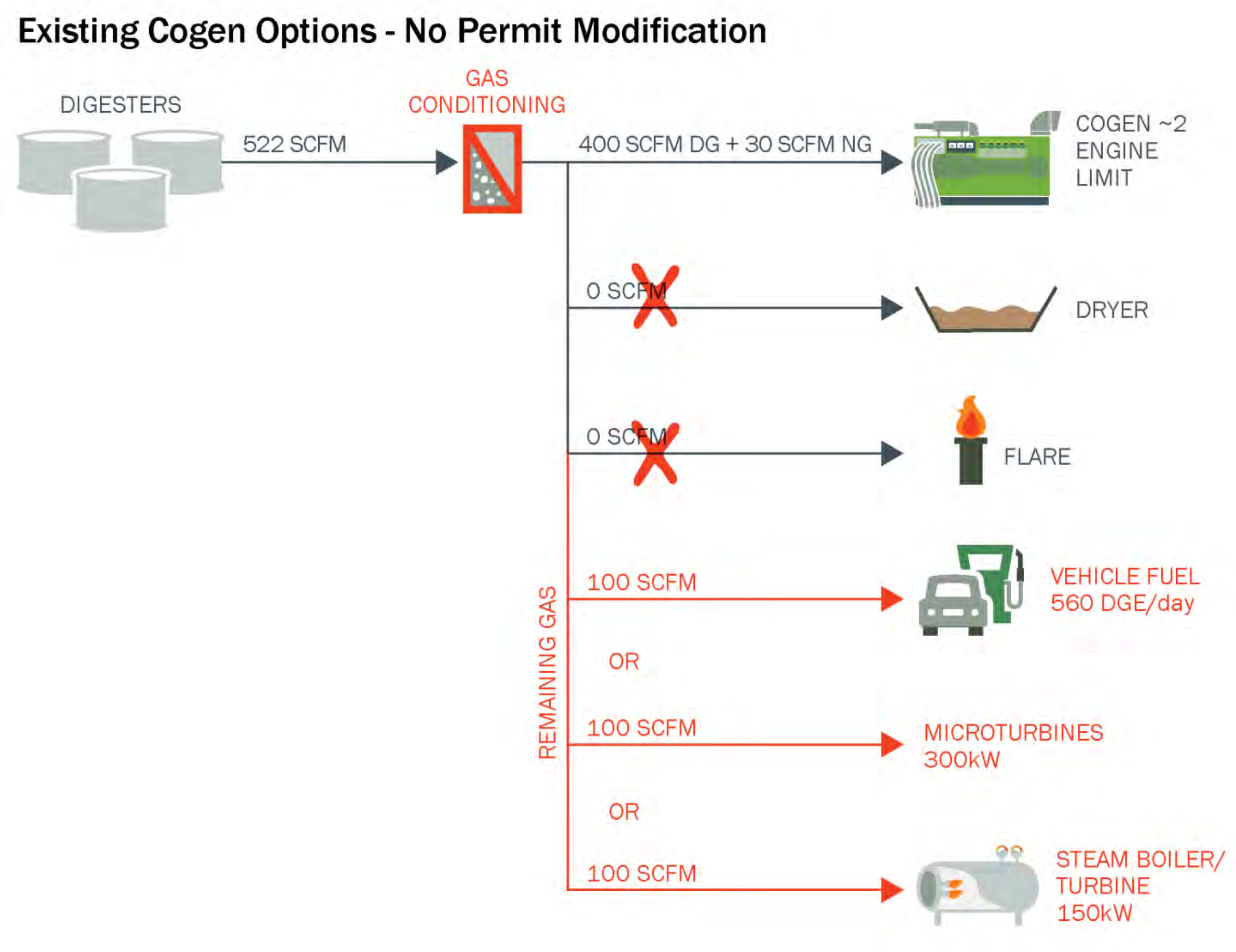
Baseline includes cogeneration (permit limited), dryer and some flaring



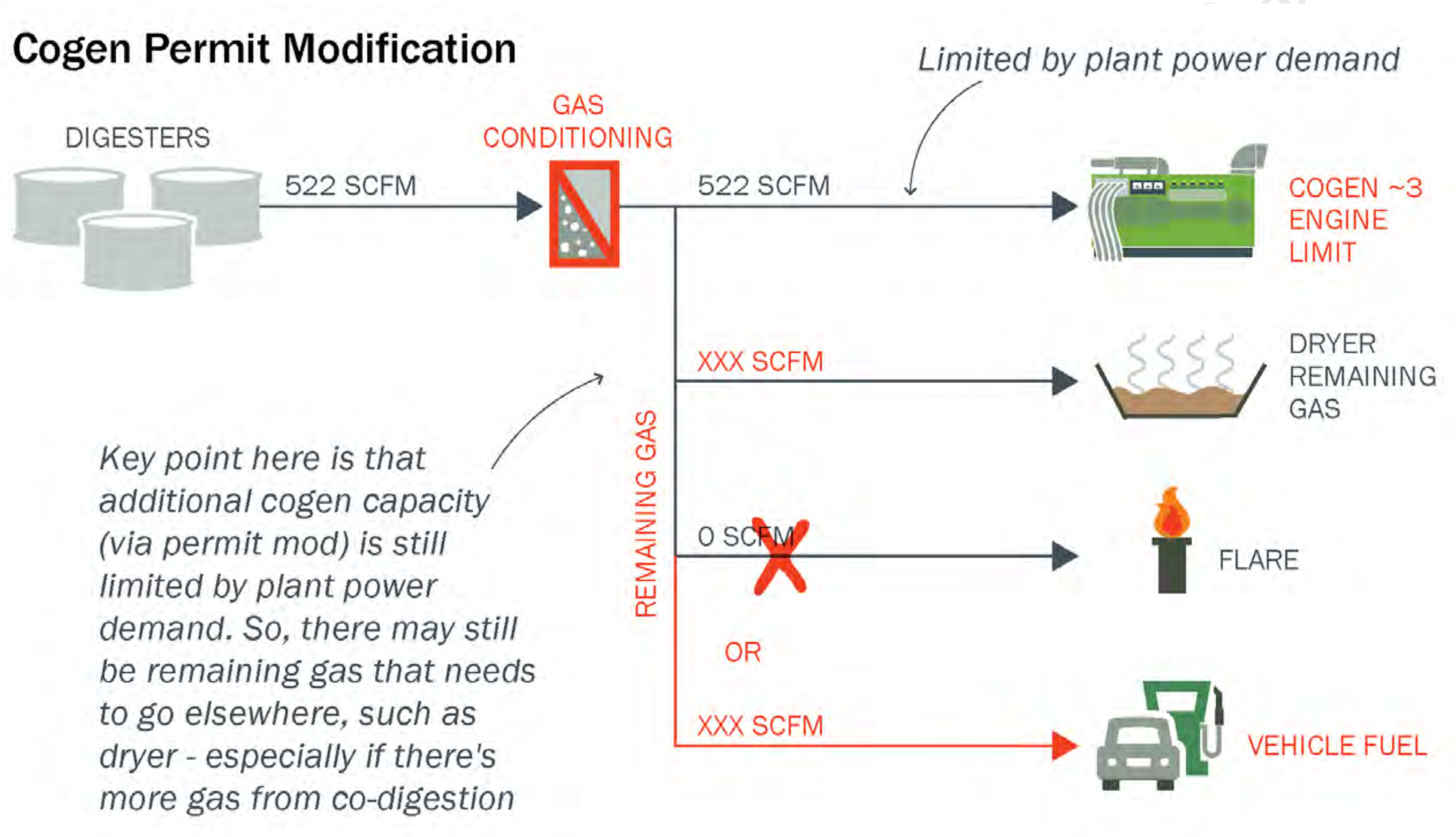
Gas conditioning could reduce engine and dryer O&M costs associated with siloxanes



With the existing permit in place, where else can we send digester gas to get highest value?

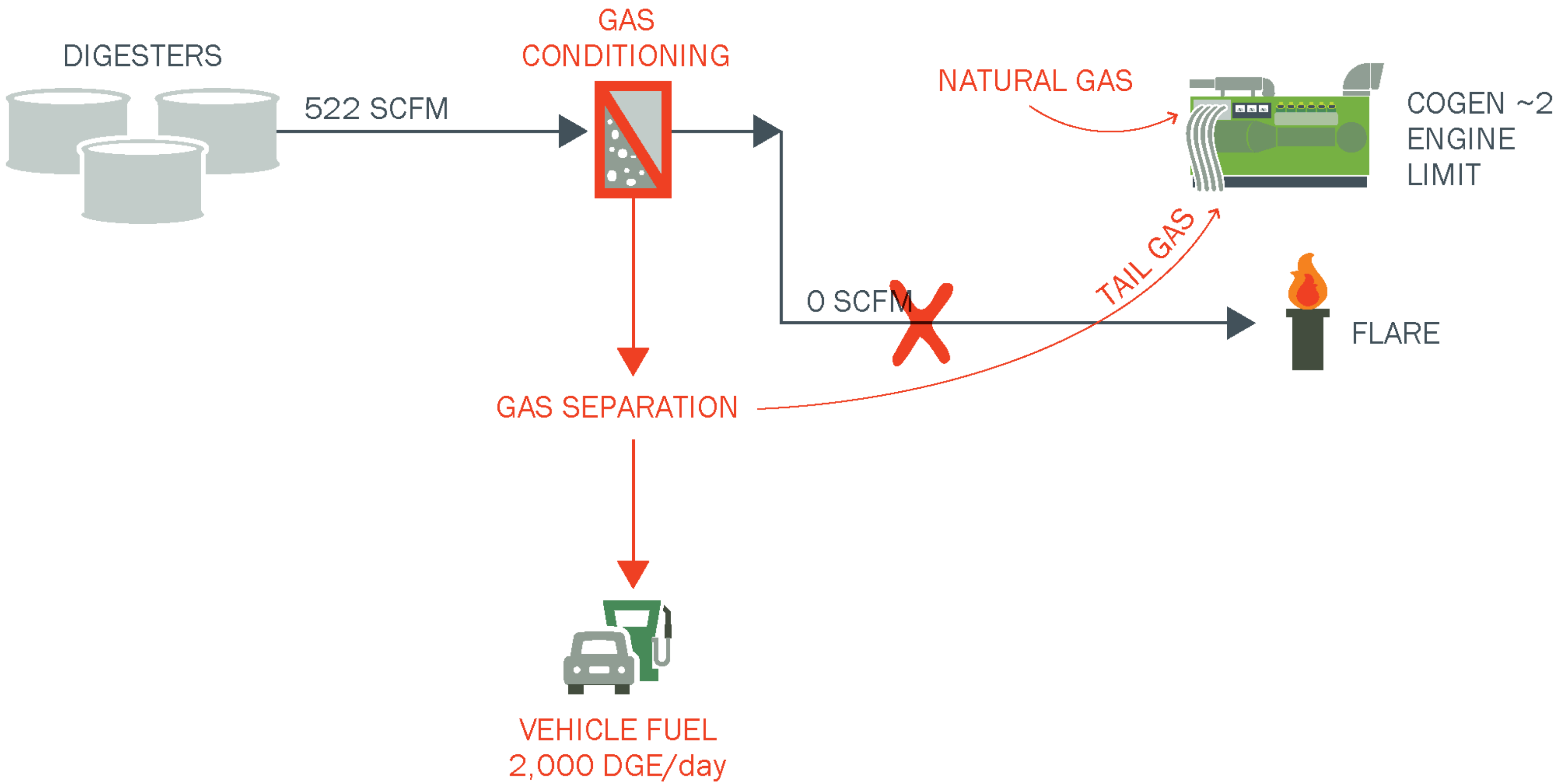


A permit modification allows EWA to meet plant electricity demand, but any additional gas would need to go to a non-generating use



An all-vehicle-fuel option may deliver the best economics

Vehicle Fuel



Alternatives to be presented at next workshop

- Process schematic
- General overview (pros and cons)
- Footprint
- Potential locations

Grant Updates

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Self Generation Incentive Program

Program	Self-Generation Incentive Program (SGIP)
Agency	California Energy Commission / administered by SDG&E
Eligible Projects	Self-generation projects such as new engines, microturbines, or steam turbines – increased incentives for renewable/biogas projects; Energy storage / batteries
Funding	Incentives based on anticipated power output – based on fuel availability, not nameplate capacity; 50% paid upfront / 50% paid over 5 years based on performance
Schedule	Funding available each year / first-come, first-served Battery funding decreases as tiers fill up Projects must be operational within 18 months of award
How much are we talking?	~$500k - $1M depending on project size
Recommendation for SWEET Analysis	Don't count on funding to justify project economics
Next steps	Continue to track / pursue if selected alternatives meet criteria

Low-Carbon Fuel Standard

Program	Low-Carbon Fuel Standard (LCFS)
Agency	California Air Resources Board
Eligible Projects	Part of AB 32 scoping plan – projects that reduce the carbon intensity of California's vehicle fuel – i.e. renewable compressed natural gas (CNG vehicle fuel)
Funding	Incentives based on fuel production, market-based values; Paid on a per-gallon basis as the project performs
Schedule	Ongoing program, recently extended through 2030
How much are we talking?	Varies … could equate to ~$0.50/DGE - $1.00/DGE depending on market factors
Recommendation for SWEET Analysis	Include in SWEET analysis for vehicle fuel projects; Assume funding only through 2030, use conservative values
Next steps	Continue to track / pursue if vehicle fuel is recommended

Renewable Fuel Standard

Program	Renewable Fuel Standard
Agency	US Environmental Protection Agency
Eligible Projects	Renewable fuel projects– i.e. renewable compressed natural gas (CNG vehicle fuel)
Funding	Incentives based on fuel production, market-based values; Paid on a per-gallon basis as the project performs
Schedule	Ongoing program, not guaranteed beyond 2022
How much are we talking?	A lot of uncertainty: Wastewater digester gas is eligible for highest value of RINs – D3 EPA has recently stated that DG from food waste is a lower value – D5 EPA has the ability to set RIN quotas, which drive supply-and-demand, market-based pricing
Recommendation for SWEET Analysis	Include in SWEET analysis for vehicle fuel projects; Assume funding only through 2022, use conservative values
Next steps	Continue to track / pursue if vehicle fuel is recommended

Organics Grant Program

Program	Organics Grant Program
Agency	Department of Resource Recovery and Recycling (CalRecycle)
Eligible Projects	Projects that serve to divert organics (food waste) from landfill – toward anaerobic digestion or composting; recently issued with a food rescue requirement
Funding	Incentives based on project size and potential tons diverted
Schedule	Recently awarded, not expected to reissue for ~18 months
How much are we talking?	Up to $4M per project
Recommendation for SWEET Analysis	Do not include – too competitive to count on
Next steps	Continue to track / pursue if food waste receiving is recommended

Organics Grant Program - Recent Award

Recommendation:
Staff recommends approval of 10 grant awards, as listed in Table 1 below, for $24,000,000.

Table 1. Organics Grant Program Recommended Award – List A

Applicant	County	Total Award
Anaerobic Digestion Projects		
County Sanitation Districts of Los Angeles County	Los Angeles	$4,000,000
HZIU Kompogas SLO, Inc.	San Luis Obispo	$4,000,000
Rialto Bioenergy Facility, LLC	San Bernardino	$4,000,000
	Subtotal	**$12,000,000**
Compost Projects		
City of San Diego	San Diego	$3,000,000
Mid Valley Recycling, LLC	Fresno	$1,875,000
Salinas Valley Solid Waste Authority	Monterey	$1,341,865
Recology Yuba-Sutter *(partially funded)*	Yuba	$2,783,135
	Subtotal	**$9,000,000**
Rural Compost Projects		
Napa Recycling & Waste Services, LLC	Napa	$541,700
South Lake Refuse Company, LLC	Lake	$1,218,026
West Coast Waste *(partially funded)*	Madera	$1,240,274
	Subtotal	**$3,000,000**
	Grand Total	**$24,000,000**

Organics Grant Program - Recent Award

Table 2. Organics Grant Program Recommended Award – List B

Applicant	County	Total Award Requested*
Anaerobic Digestion Projects		
CR&R Incorporated	Riverside	$4,000,000
Contra Costa Waste Services	Contra Costa	$4,000,000
City of Manteca	San Joaquin	$1,500,000
Santa Barbara County	Santa Barbara	$4,000,000
Subtotal		**$13,500,000**
Compost Projects		
Recology Yuba-Sutter *(partially funded)*	Yuba	$216,865
Agromin OC, LLC	San Bernardino	$600,000
Waste Management of Alameda County, Inc.	Alameda	$3,000,000
GreenWaste Recovery, Inc.	Santa Clara	$1,700,000
Burrtec Waste Industries, Inc.	Riverside	$3,000,000
Arakelian Enterprises Inc. DBA Athens Services	San Bernardino	$3,000,000
Best Way Disposal Company, Inc. DBA Advance Disposal Co.	San Bernardino	$2,481,250
Kern County	Kern	$3,000,000
City of Oceanside	San Diego	$1,178,351
Subtotal		**$18,176,466**
Rural Compost Projects		
West Coast Waste *(partially funded)*	Madera	$161,326
Upper Valley Disposal Service	Napa	$1,250,000
Subtotal		**$1,411,326**
	Grand Total	**$33,087,792**

Heathy Soils Program

Program	Healthy Soils Program
Agency	California Department of Food and Agriculture
Eligible Projects	Demonstration projects that sequester carbon and reduce GHG emissions – groups within CASA
Funding	Incentives based on project size and potential GHG benefit
Schedule	Currently accepting applications through September 19 Annual funding program (AB 32 funds), amounts and criteria may vary
How much are we talking?	Up to $3.75M total
Recommendation for SWEET Analysis	Do not include / ancillary benefit to support end use program
Next steps	Continue to track / connect with CASA Science and Research Group for potential partnerships

Green Project Reserve

Program	Green Project Reserve
Agency	California Water Resources Control Board
Eligible Projects	Projects that improve energy efficiency, renewable energy generation, or recycled water production
Funding	A component of Clean Water State Revolving Funding; Green Project Reserve is a “loan forgiveness” program CWSRF is generally oversubscribed, but GPR is underutilized
Schedule	Ongoing
How much are we talking?	Up to $4M per project, or 50% of project value, whichever is higher
Recommendation for SWEET Analysis	Do not include
Next steps	Something for EWA to keep in mind – if a larger capital project requires funding, consider CWSRF and adding an eligible GPR component

Air Permitting Discussion

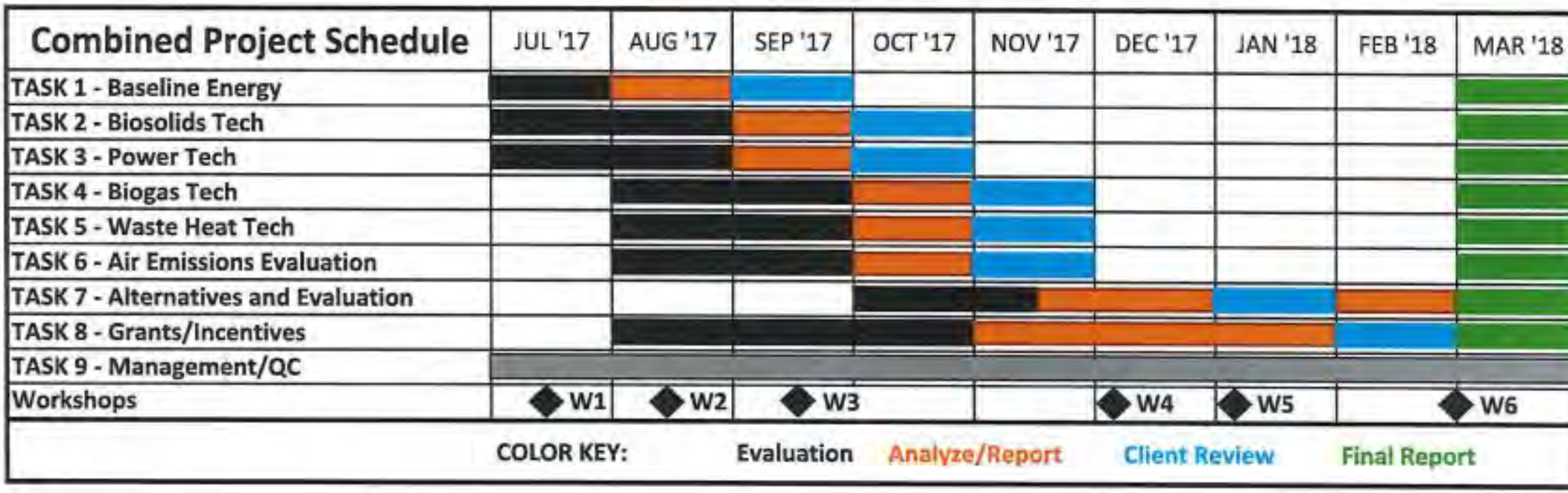
EWA is actively pursuing air permit modification

- EWA (with Don King) will submit a request for permit modification within ~1 week
- Goal is to adjust the CO emission rate from 530 ppm to ~400 ppm, and thereby adjust the fuel input limit aimed at keeping CO emissions below Title V synthetic minor threshold
- If successful, this effort would increase permitted cogen capacity by ~20%
- This increase would allow EWA to meet plant electricity demand with current digester gas flows and cogen system

Look Ahead & Wrap-Up

Project Schedule

- Workshop #3 in mid-September
- Draft Analysis and Reports to Begin



Look Ahead – September Workshop

- Consensus on mass balance/baseline
- Conceptual layouts/details of alternatives for consensus/feedback (example numbers to support including biogas production, food waste that can be imported)
- Air permitting impacts on power production alternatives
- Informational meeting with waste haulers
- Debrief on Anaergia meeting
- Grants update

Wrap-Up

QUESTIONS?

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Technical Memorandum

FINAL

Prepared for: Encina Wastewater Authority

Project Title: Biosolids, Energy and Emissions

Project No.: 150871.006

Technical Memorandum No. 6

Subject: Air Emissions

Date: February 13, 2018

To: Scott McClelland, Assistant General Manager

From: Scott Lacy, Project Manager

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Don Trueblood, Senior Expert

Limitations:

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Executive Summary

The Encina Water Pollution Control Facility (EWPCF) currently has four 750-kilowatt (kW) internal combustion (IC) engines, a biosolids dryer, a waste gas flare, and a wet scrubber and regenerative thermal oxidizer. Operation of and air emissions from these technologies are currently regulated by the San Diego Air Pollution Control District. Changes to biosolids processing, energy production and utilization, and waste heat recovery that are covered in Technical Memoranda (TMs) 2, 3, 4, and 5 may require modifications to the existing air permits or new air permits. Specific regulatory requirements for alternatives that produce emissions and pass fatal-flaw filters in TMs 2, 3, 4, and 5 are discussed in this TM 6. Alternatives that may require permitting changes include:

- Changes to thermal drying operation
- Changes to internal combustion engine operation
- Addition of microturbines for power generation
- Addition of boilers to provide steam for a Cambi™ thermal hydrolysis process
- Changes to odor control equipment associated with new odor sources
- Addition of digester gas conditioning
- Addition of digester gas upgrading for pipeline injection or vehicle fuel
- Addition of digester gas storage

New regulations and regulatory trends that may impact future air permitting for EWPCF were also assessed as part of this TM.

Last, a greenhouse gas (GHG) inventory was performed for the existing gas utilization technologies, including the engines, thermal biosolids dryer, RTO, and flare. Potential GHG reductions associated with future energy production alternatives are included in the discussion of the GHG inventory.

Section 1: Introduction

EWA has undertaken a Biosolids Energy and Emissions Plan (BEE Plan) which will be used to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed Process Master Plan. The BEE Plan has several goals:

1. Provide a comprehensive analysis of all project elements including biosolids treatment, gas use, energy generation, and waste heat;
2. Address capacity limitations in the solids handling process at the EWPCF;
3. Assess which alternative is likely to be the most cost effective and sustainable solution for EWA;
4. Move the EWPCF toward greater energy independence; and
5. Reduce greenhouse gas emissions.

The purpose of TM 6 is to review permit requirements related to air emissions associated with the cogeneration operation. This TM explores opportunities to remove the air permit constraints to optimize the use of the existing IC engines, presents pathways to meet Best Available Control Technology (BACT) and other air emission requirements for potential alternatives in TMs 3, 4 and 5, and presents the greenhouse gas inventory (GHG) for the existing operation that future alternatives can be measured against.

1.1 Existing SDAPCD Permit

The EWPCF is regulated under the San Diego County Air Pollution Control District (SDAPCD). SDAPCD permits establish operating limits based on maximum estimated emissions levels that must be confirmed by regular source testing. Regulated processes at the plant include stationary sources and abatement devices. Emissions requirements differ between stationary sources and abatement devices. Major stationary sources at the plant are:

- One Andritz DDS40 biosolids dryer
- Four Caterpillar G3516 750-kW lean-burn internal combustion (IC) engines

Abatement devices at the plant are:

- One Varec Biogas 244 Series enclosed flare
- One wet scrubber and one CECO Systems regenerative thermal oxidizer (RTO), which are coupled with the biosolids dryer

The air permits for the four IC engines limit fuel consumption and emission of criteria air pollutants. EWA pursued air permit modifications for the IC engines to increase the permitted fuel consumption. An updated IC engine air permit was received on November 8, 2017 (Attachment A). Fuel consumption and emission limits for the IC engines from the previous permit and the new permit are summarized in Table 1-1. The IC engine air permits also delineate source testing, maintenance, record-keeping, and site accessibility requirements.

Table 1-1. Previous and Existing Air Permit Requirements for the IC Engines

Requirement	Previous Permit Limit	New Permit Limit	Units
Nitrogen oxides (NO_x) emissions limit, digester gas	47	47	Parts per million by volume (ppmv)
NO_x emissions limit, natural gas	54	54	ppmv
Carbon monoxide (CO) emissions limit, digester gas	569	400	ppmv
CO emissions limit, natural gas	390	390	ppmv
Annual fuel consumption, total	224,000,000	280,000,000	Standard cubic feet (scf)
Annual fuel consumption, natural gas	22,400,000	28,000,000	scf
Daily fuel consumption, digester gas	1,000,000	1,000,000	scf
Daily fuel consumption, natural gas	550,000	550,000	scf

Note: Fuel consumption limits include all four engines.

No modifications to the air permits for the biosolids dryer, flare, and wet scrubber and RTO have been requested, but EWA may need to pursue an updated flare permit to meet projected digester gas production. The potential for a new flare permit is discussed further in Section 2.5. The current flare permit allows digester gas usage of 300 million scf/year, which equates to approximately 570 scf/minute. Flare operation, maintenance, and monitoring requirements are also defined in the permit.

1.2 Synthetic Minor Facility

EWPCF currently operates as a Synthetic Minor Facility, meaning the facility's stationary emissions sources have the potential to exceed at least one of the Title V Major Source thresholds. For reference, the Major Source thresholds are provided in Table 1-2. Stationary emission sources at EWPCF are operated to keep the facility within the Synthetic Minor Facility confines. Historically, CO has been the limiting air pollutant (i.e. CO emissions have been closest to the applicable Major Source threshold). IC engine operation produces most of the CO emissions.

Table 1-2. Title V Major Source Emissions Thresholds

Pollutant	Emissions Threshold (tons/year)
Volatile organic compounds (VOCs)	100
Inhalable particulates (PM10)	100
Sulfur dioxide (SO_2)	100
NO_x	100
CO	100
Ozone depleting compounds	100
Lead compounds	10
Single Hazardous Air Pollutant	10
Combination of Hazardous Air Pollutants	25

Section 2: Future Alternatives

All alternatives that involve future modifications or additions of equipment that may produce air emissions must be compliant with current SDAPCD, California Air Resources Board (CARB), and federal regulations.

First, considerations for EWPCF's Synthetic Minor status must be made when evaluating alternatives. Some alternatives, such as expanding IC engine operation or adding a second biosolids dryer, may cause annual emissions of one or more regulated pollutants to exceed the respective Major Source threshold. Because CO emissions at EWPCF have historically been close to this limit, additional CO emissions from future alternatives and CO emissions controls must be weighed when evaluating these alternatives. Exceeding any Major Source threshold would change EWPCF's status from a Synthetic Minor facility to a Title Major Source Facility. Obtaining a Title V permit involves significant costs and reporting requirements, and EWA has expressed a desire to maintain EWPCF's Synthetic Minor Source status.

Under SDAPCD rules, BACT must be applied to "any new, modified, relocated, or replacement emission unit which is required to obtain an Authority to Construct and/or Permit to Operate pursuant to Rule 10, which will result in an increased potential to emit, and which has a post-project potential to emit 10 or more pounds per day of the pollutant being increased" (SDAPCD, 2011). BACT is determined on a pollutant by pollutant basis, and pollutants included in this rule are inhalable particulates (PM_{10}), NO_x, volatile organic compounds (VOCs), and sulfur oxides (SO_x). In addition to the BACT determinations presented in the SDACPD BACT Guidance Document, BACT determinations from CARB and the federal Environmental Protection Agency (EPA) may be applied at the discretion of SDAPCD. It is important to note that BACT is a continuously changing standard, and BACT determinations presented in this document may not be considered BACT when a new or modified permit is pursued.

Relevant federal regulations include the New Source Performances Standards (40 CFR Part 60) and the National Emission Standards for Hazardous Air Pollutants (40 CFR Part 63). While BACT only applies at the time of permitting, performance standards are always applicable. These standards are specified for different types of equipment, and specific applicable emissions restrictions are presented in the following subsections.

When evaluating alternatives presented in TMs 3, 4, and 5, compliance with BACT and any other relevant air pollution regulations has been included in the analyses. Compliance with these air regulations will be considered in all future analyses, as well. Specific BACT and regulatory requirements for alternatives that produce emissions and pass fatal-flaw filters in TMs 3, 4, and 5 are discussed in this section.

2.1 Biosolids Drying – Thermal Dryer

EWPCF has one existing Andritz DDS40 biosolids dryer that is fueled by a mix of digester gas and natural gas. The fuel mixture is approximately 80 percent natural gas and 20 percent digester gas, and approximately 9 MMBtu/hr of fuel is consumed. The current fuel consumption was calculated assuming the dryer opperates 11 days every two weeks. The dryer is capable of utilizing a fuel mix with up to 80 percent digester gas; however, this fuel mixture has not been tested. Exhaust from the dryer furnace is treated by a wet scrubber and a RTO that is fueled by natural gas.

As discussed in TM 2, drying capacity may be increased. A second biosolids dryer may be installed, which will require a new air permit application. Additionally, the digester gas compostion of the dryer fuel may be increased. EWA is in ongoing discussions with Andritz on how to modify the Solids Building to accommodate dryer modifications, but do not anticipate these changes will impact the air permit. Since plans to modify the building are not finalized, the permit should be revisited once the size of the dryer and RTO are selcted.

Biosolids dryers are not covered in SDAPCD's BACT Guidance Document, but the CARB BACT Clearinghouse contains BACT determinations for large industrial ovens and dryers. BACT determinations are available for units with capacities between 1.9 MMBtu/hr and 96 MMBtu/hr. For all units within this range, low-NO_x burners are considered BACT.

2.2 Internal Combustion Engines

Increasing the fuel input to the existing IC engines at EWPCF has been presented as an alternative power production strategy in TM 3. As stated in Section 1.1, EWA received a modification to the existing IC engine permits that allows expanded digester gas and natural gas use. Increasing fuel use beyond these new permit regulations will trigger BACT.

Lean-burn IC cogeneration engines fueled by digester gas and natural gas are not covered in SDAPCD's BACT Guidance Document; however, BACT information for these engines is contained within the CARB BACT Clearinghouse. According to the BACT Clearinghouse, BACT for NO_x, CO, and VOC control is selective catalytic reduction (SCR) combined with an oxidation catalyst. However, installing and maintaining a SCR system is typically cost prohibitive, and SDAPCD has historically not required SCR for digester gas fueled IC engines.

Expanding IC engine operation under the new air permit may cause EWPCF's CO emissions to increase beyond the Major Source threshold. In this case, EWA may reduce engine operation to limit CO emissions, or oxidation catalysts can be added to reduce CO emissions while maximizing engine output. If oxidation catalysts are installed, an upstream gas conditioning system must also be installed to reduce harmful contaminants that can poison catalysts. Oxidation catalysts are relatively inexpensive compared to full SCR systems and can be economical options for controlling CO emissions.

SCR and oxidation catalysts both operate via catalysis, which is a process that significantly increases the rate of a chemical reaction. SCR systems are active abatement devices in which ammonia (NH_3) is injected as urea and reacts with NO_x molecules in the IC engine exhaust to produce nitrogen and water vapor. Oxidation catalysts are passive abatement devices that reduce CO and VOCs to CO_2 and water vapor; no additional reactants must be supplied for the oxidation process. An exhaust treatment process flow diagram is provided in Figure 2-1.

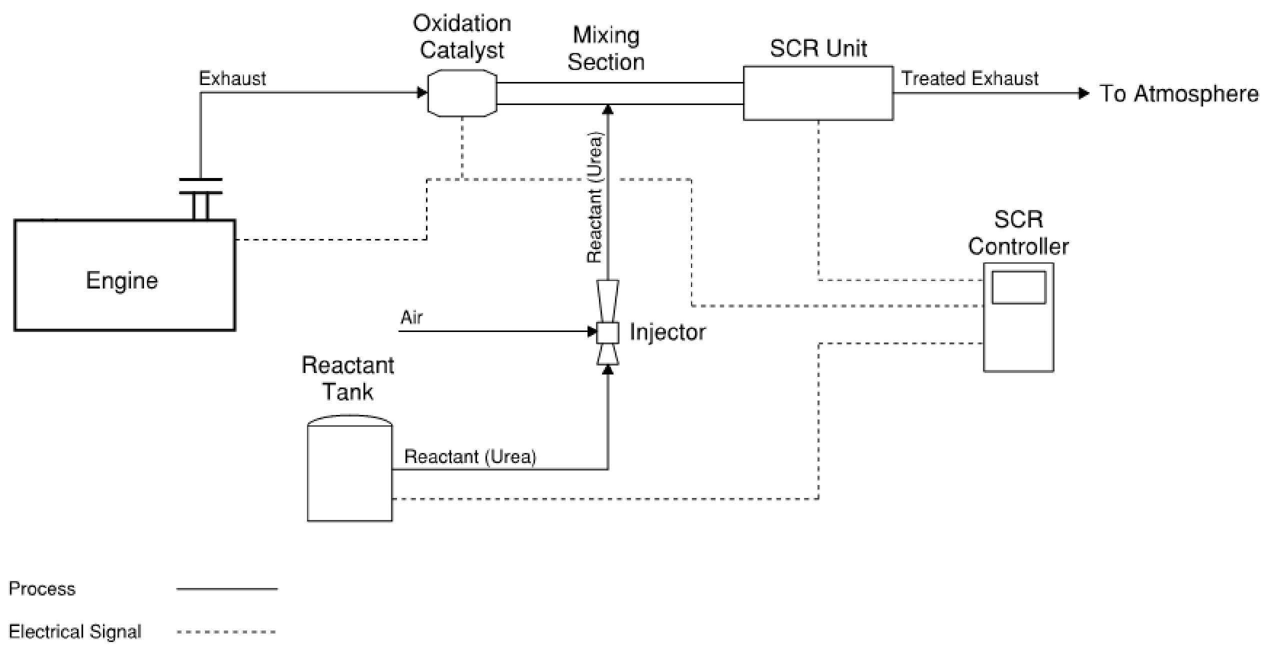

Figure 2-1. A post-combustion exhaust treatment system, including an oxidation catalyst, urea dosing, and an SCR unit

In addition to BACT, state and federal performance standards apply to operation of natural gas and digester gas fueled IC engines. Relevant standards are presented in Table 2-2. These standards are preliminary determinations, and specific limits are applied when an emissions source is permitted.

Table 2-1. Relevant Federal Emissions Regulations for IC Engines

Requirement	Limit	Units	Regulation
Formaldehyde, reduction	76 or greater	%	40 CFR Part 63 Subpart ZZZZ
Formaldehyde, emissions limit	350	ppbv	40 CFR Part 63 Subpart ZZZZ
NO_x emissions limit, digester gas	150	ppmv	40 CFR Part 60 Subpart JJJJ
NO_x emissions limit, natural gas	82	ppmv	40 CFR Part 60 Subpart JJJJ
CO emissions limit, digester gas	610	ppmv	40 CFR Part 60 Subpart JJJJ
CO emissions limit, natural gas	270	ppmv	40 CFR Part 60 Subpart JJJJ
VOC emission limit, digester gas	80	ppmv	40 CFR Part 60 Subpart JJJJ
VOC emissions limit, natural gas	560	ppmv	40 CFR Part 60 Subpart JJJJ

2.3 Microturbines

Microturbines are small combustion turbines that cogenerate heat and electricity and are included in TM 3 as a power production alternative. Digester gas, natural gas, or a combination can be used to fuel microturbines.

As stated in the Section 2 Introduction, BACT must be applied when an emission unit has a potential to emit 10 or more pounds per day of PM_{10}, NO_x, VOCs, or SO_x. Microturbines are low-emission combustion units, and most available models from Capstone and FlexEnergy do not trigger BACT because full load emissions of each pollutant of concern are below the 10 pounds per day threshold. Of all the Capstone 65 kW AND 200 kW units, only the CR 200 Digester Gas model exceeds one of the BACT thresholds. The CR200 Digester Gas model produces 3.6 lb/MW-hr of CO at full load, which is equivalent to 17.3 lb/day of CO. Even if two 200-kW units are installed, the only BACT exceedance is the CO limit. In this case, an oxidation catalyst would be required. Refer to Section 2.2 for information on using oxidation catalysts to control CO.

2.4 Boilers

In TM 4, the Cambi™ thermal hydrolysis process (THP) is presented as an alternative to increase biogas production. Refer to Section 2.5 for additional air emissions impacts of Cambi™ THP. This process uses medium-pressure steam, which must be produced in boilers. Conventional or composite boilers may be installed as part of this alternative, and boilers may be fueled by digester gas, natural gas, or a combination of the two.

Under SDAPCD rules, new boilers must meet BACT standards. For natural gas boilers with a heat input of less than 50 MMBtu/hr, BACT is a low NO_x burner, flue gas recirculation, and oxygen controller. According to the SDAPCD BACT Guidance Document, in lieu of meeting the BACT requirement, EWA may choose to limit the potential to emit from the boilers to less than 10 pounds per day. However, CARB and EPA BACT databases contain more stringent for natural gas fueled boilers including EMx, also known as SCONOx™, and SCR. Refer to Section 2.2 for a description of SCR. EMx has been shown to achieve lower NO_x emissions than SCR under some conditions.

EMx operates via a catalysis/absorption cycle to remove NO_x and CO. The system employs a platinum catalyst impregnated with potassium carbonate. Both NO_x and CO are oxidized by the platinum catalyst, and the oxidized NO_x reacts with the potassium carbonate and is absorbed within the catalyst surface. Potassium carbonate must be regenerated with hydrogen when saturated with NO_x. The regeneration process must take place in an oxygen-free environment, which is achieved via valves and louvers. Elemental nitrogen and water vapor are released during regeneration. Various sections of catalysts alternate between oxidation/absorption and regeneration. There are several critical issues associated with EMx that should be considered, including sensitivity to sulfur, safety issues with use of hydrogen, and a high capital cost.

Flue gas recirculation diverts flue gases from the boiler exhaust stream to the combustion chamber, which reduces the peak flame temperatures, decreases the oxygen content in the combustion air, and slows the combustion process. This process controls thermal NO_x formation, which occurs at higher combustion temperatures and oxygen contents. A flue gas recirculation system for a boiler is shown in Figure 2-2. Oxygen controllers reduce NO_x by limiting the amount of excess air provided for the combustion process, which controls the oxygen to fuel ratio.

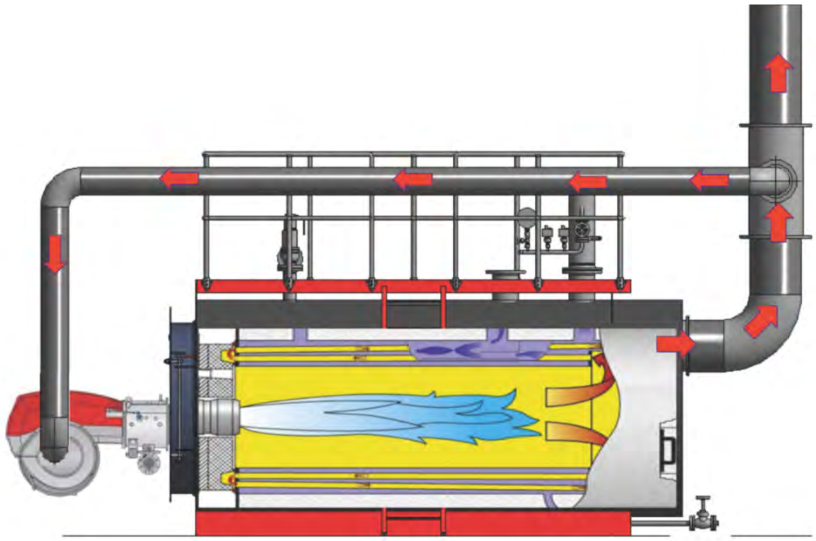

Figure 2-2. Flue gas recirculation in a natural gas boiler.

Source: Bosch.

In addition to BACT, state and federal performance standards apply to operation of natural gas and digester gas fueled boilers. Relevant standards are presented in Table 2-2. These standards are preliminary determinations, and specific limits are applied when an emissions source is permitted.

Table 2-2. Relevant Federal Regulations for Boilers

Requirement	Limit	Units	Notes	Regulation
CO emissions limit, gaseous fuel	130	ppmv	Dry basis, corrected to 3 % oxygen	40 CFR Part 63 Subpart DDDDD
Hydrogen chloride, gaseous fuel	1.7×10^{-3}	lb/MMBtu of heat input	N/A	40 CFR Part 63 Subpart DDDDD
Mercury, gaseous fuel	7.9×10^{-6}	lb/MMBtu of heat input	N/A	40 CFR Part 63 Subpart DDDDD
Filterable PM, gaseous fuel	6.7×10^{-3}	lb/MMBtu of heat input	N/A	40 CFR Part 63 Subpart DDDDD

2.5 Flare

As stated in Section 1.1, the current flare permit allows digester gas usage of 300 million scf/year. Current digester gas production at EWPCF is below this limit, but, according to TM 1, digester gas production is projected to exceed 300 million scf/year between 2020 and 2030. These projections assume that high strenth waste (HSW) codigestion remains constant. If EWPCF starts accepting additional HSW deliveries, digester gas production may exceed the flare permit limit earlier than 2020. At current conditions, codigesting an additional 7,000 lb of HSW will cause digester gas production to exceed the flare permit limit.

Installation of a higher capacity flare will be required when digester gas production exceeds the current permit's limit, and a modified flare permit must be obtained. The new flare should be sized with digester gas production projections in mind.

2.6 Odor Control

EWPCF currently has three odor reduction facilities (ORF1, ORF 2, and ORF3). ORF 1 and ORF 3 are covered under a single air permit, and ORF 2 is covered under the permit for the biosolids processing facility. Cambi™ THP and increased codigestion, which are discussed in TMs 2 and 4, may produce additional odors that are subject to regulation. If impacts to the existing odor reduction facilities exceed the current air permit limitations, a modified air permit for odor reduction must be developed. Odor mitigation measures and possible air permitting requirements are included in current analyses and will be considered in future analyses.

2.7 Other Alternatives

There are several other alternatives that have passed the fatal-flaw filters in TMs 3, 4, and 5 that may or may not require air permitting.

Cambi™ THP, which is mentioned in Section 2.4, usually increases the NH_3 content in digester gas, which results in greater NO_x formation during combustion in an engine, flare or dryer, and can cause exceedances of emissions limits. To avoid potential NO_x issues, NH_3 removal can be added to a gas conditioning system.

Gas conditioning systems can be considered permittable abatement devices because these systems reduce the concentrations of regulated air pollutants in digester gas, including SO_x and NO_x. An air permit is required for a gas conditioning system if employed in conjunction with a combustion process (e.g. an IC engine, microturbine, and/or a flare). An air permit is not required if the gas conditioning system is associated with a permit-exempt emission source.

A digester gas upgrading system for either pipeline injection or direct vehicle fueling may also require an air permit. Upgrading systems separate the methane and carbon dioxide in digester gas, which produces a methane-rich product gas and a tail gas that is mostly carbon dioxide. The tail gas may or may not contain a significant quantity of methane, depending on the separation efficiency of the digester gas upgrading process. Separation efficiencies typically vary between 90 percent and 99+ percent. If the tail gas contains a significant quantity of methane, air permitting and emissions control will most likely be required. Even if tail gas has a negligible methane concentration, an air permit may still be required.

Although digester gas storage does not produce or affect emissions, adding digester gas storage changes the currently permitted process, which requires a permit modification.

Small-scale and large-scale solar photovoltaics do not require an air permit.

Section 3: Future Regulations

New regulations and regulatory trends that may impact future air permitting for EWPCF were assessed as part of this TM. Two relevant regulatory developments were identified, California Assembly Bill 617 and forthcoming SCR requirements. Brief descriptions of these regulatory developments are provided in this section.

3.1 California Assembly Bill 617

The State of California recently passed Assembly Bill (AB) 617 Nonvehicular Air Pollution: Criteria Air Pollutants and Toxic Air Contaminants, which has a wide range of impacts on air regulations. The most relevant change of AB 617 is that it requires air districts to adopt an implementation schedule for best available retrofit technology (BARCT) that applies to all emissions producing equipment that received new or revised air permits prior to 2007. Eligible equipment must be upgraded by December 31, 2023. In other words, even if no major modifications are made to a piece of equipment, that equipment must comply with the appropriate air district's new BARCT regulations if it was permitted prior to 2007.

3.2 SCR for All Digester Gas Fueled IC Engines

Air districts in the state of California may move to require SCR emissions control as BACT for all digester gas fueled IC engines in California. The Bay Area Air Quality Management and South Coast Air Pollution Control Districts have been the first districts to implement this requirement for SCR, and California's other air districts may follow this lead. It is uncertain when California's other air districts may adopt these stricter SCR requirements, but it is important for facilities with digester gas fueled IC engines to be aware of this trend.

Section 4: Greenhouse Gas Inventory

A GHG inventory was performed for the existing gas utilization technologies, including the engines, thermal biosolids dryer, RTO, and flare. This section also includes a discussion on the potential GHG reductions associated with future energy production alternatives.

4.1 Introduction to GHG Scope Emission Categories

GHG emissions estimates are categorized as Scope 1, Scope 2, or Scope 3. Scope 1 emissions are direct GHG emissions from within a given boundary; the boundary for EWPCF's Scope 1 GHG emissions estimates developed in this TM include combustion emissions from the 1) engines, 2) thermal dryer, 3) flare, and 4) RTO. Combustion of anthropogenic fuels such as natural gas contributes to GHG emissions as well as byproducts such as CH_4 and N_2O from incomplete combustion of biogenic fuels such as biogas. GHG emissions from biogas combustion are considered biogenic and do not count towards the total emissions, but are still reported.

Scope 2 GHG emissions are associated with energy purchased through SDG&E and use the published 2014 V2 eGRID CO_2 emissions factor for the CAMX – WECC California subregion. (https://www.epa.gov/sites/production/files/2017-02/documents/egrid2014_summarytables_v2.pdf). Scope 2 GHG emissions estimates are included as part of this analysis and include EWPCF's entire operational boundary, including headworks, solids treatment, liquids treatment, building, and lighting. All energy purchased through SDG&E that is recorded on EWPCF's meter contributes to Scope 2 estimates in this TM.

Scope 3 GHG emissions are indirect emissions that are not covered under Scope 1 or 2, such as emissions from biosolids hauling. Scope 3 sources are not included in the GHG emissions estimates reported in this TM. Figure 2-1 provides a graphical representation of the three Scopes that contribute to the GHG emissions inventory. Scope 3 sources are shown in Figure 2-1 only for informational purposes.

GHG emissions estimates in this analysis are based on fuel consumption during the baseline period (June 2016 to May 2017) presented in TM 1.

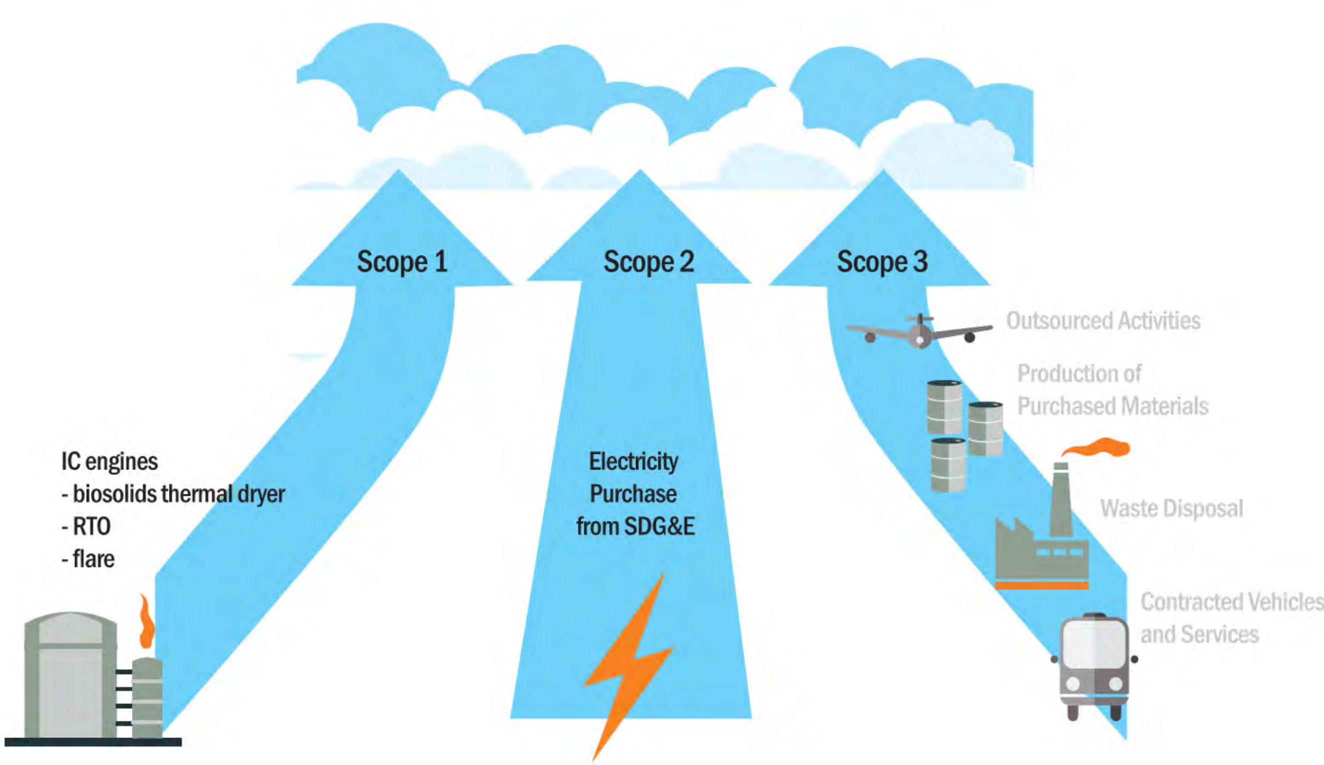

Figure 2-1. Scope 1, 2 and 3 emission categories that contribute to a typical GHG Inventory. Only Scopes 1 and 2 are included in this TM.

4.2 Current Baseline GHG Emissions

To determine the GHG inventory for the engines, biosolids thermal dryer, RTO, and flare, The Climate Registry (TCR) General Reporting Protocol (GRP) version 2.1, January 2016, methodology was applied. Equations from Chapter 12: Direct Emissions from Stationary Combustion of the GRP were used in the calculations. Additionally, the following tables from the March 2017 version of the Default Emissions Factors were used:

- Table 12.1 U.S. Default Factors for Calculating CO2 Emissions from Fossil Fuel
- Table 12.9.1 Default CH_4 and N_2O Emission Factors by Fuel Type – Industrial and Energy Sectors
- Subregion Emissions - Greenhouse Gasses (eGRID2014v2), CAMX - WECC California eGRID subregion

The estimated total GHG emissions within the established Scope 1 and 2 boundaries are 4,312 metric tons of carbon dioxide equivalents (CO_2e). This estimate does not include combustion emissions from digester gas, which are reported separately; however, emissions from incomplete combustion of digester gas is considered Scope 1. Figure 3-2 shows the fraction of GHG emissions that each Scope 1 source contributes and Table 3-1 summarizes these values.

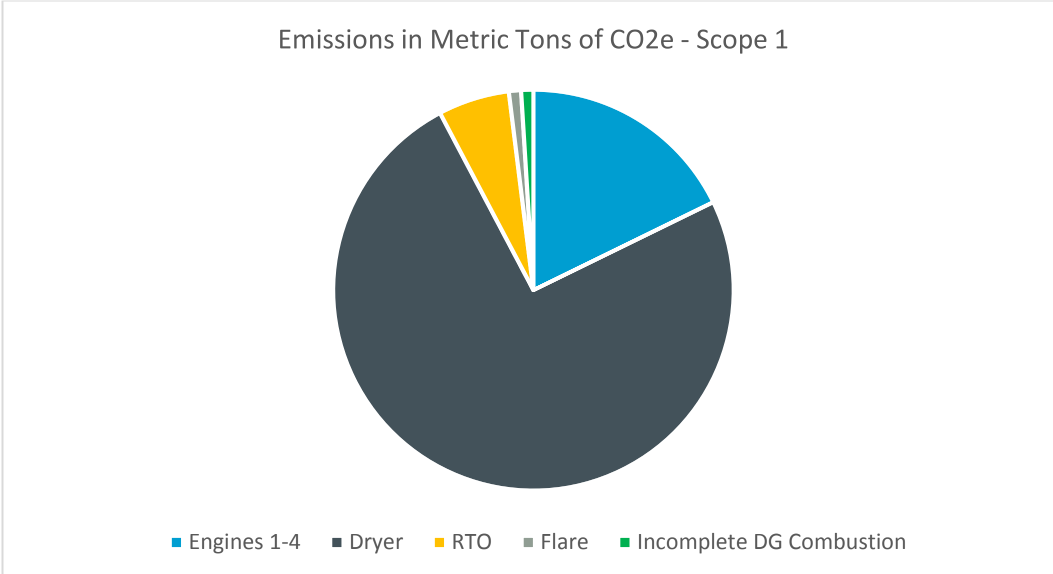

Figure 3-2. Fraction of Scope 1 GHG emissions estimates from each source

Table 3-1. Scope 1 GHG Emissions Estimates

Combustion Device	Annual NG Combustion (SCF)	Annual DG Combustion (MMBtu)	Direct CO_2e (metric tons)	CH_4 as CO_2e (metric tons)	N_2O as CO_2e (metric tons)	Incomplete Biogas Combustion (metric tons CO_2e)	Total CO_2e (metric tons)
Engines 1-4	11,563,000	11,563	614	0	0	30	644
Dryer	50,789,368	50,789	2,695	1	1	2	2,700
RTO	3,929,441	3,929	208	0	0	0	209
Flare	598,643	599	32	0	0	4	36
Total	3,588 Metric Tons						

1. *Emission factors for CO_2, CH_4, and N_2O are 53.06 kg/MMBtu, 0.001 kg/MMBtu, and 0.0001 kg/MMBtu, respectively.*
2. *Global Warming Potential for CO_2, CH_4, and N_2O is 1, 28, and 265, respectively.*

The intergovernmental Panel on Climate Change (IPCC) *Guidelines for National Greenhouse Gas Inventories* requires that CO_2 emissions from biomass combustion be reported separately from Scope 1 direct emissions. The CO_2 emissions from biogas combustion total 7,257 metric tons of CO2e. Figure 3-3 shows the fraction of GHG emissions that each combustion source contributes and Table 3-2 summarizes these values.

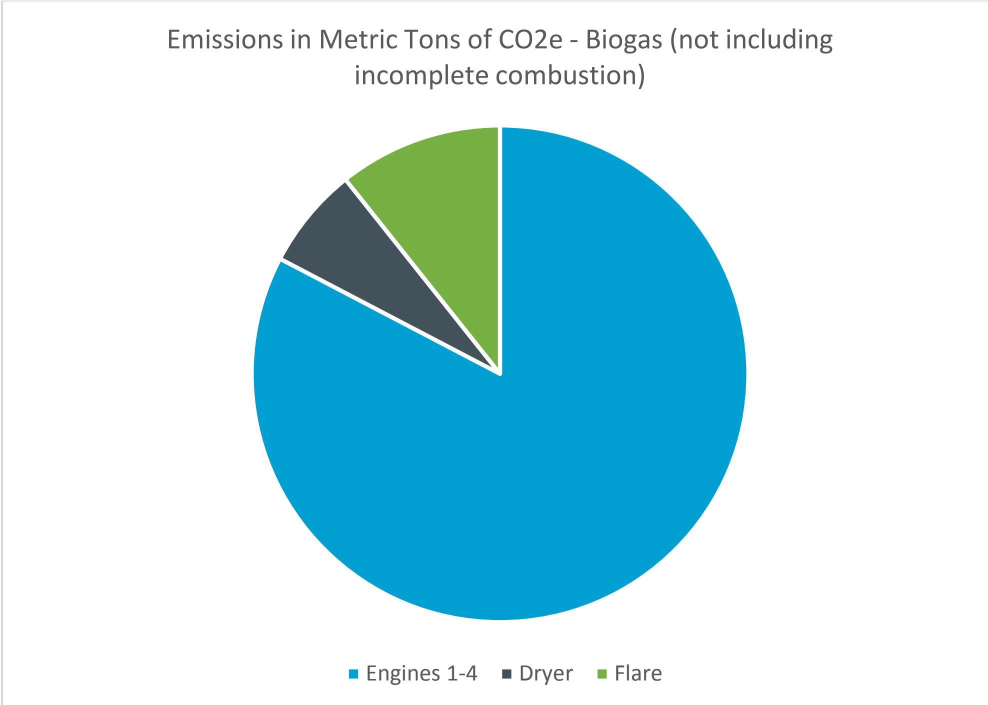

Figure 3-3. Fraction of GHG Emissions from biomass fueled combustion devices

Table 3-2. Biogas Combustion Biogenic GHG Emissions			
Combustion Device	Annual Biogas Combustion (SCF)	Annual Biogas Combustion (MMBtu)	CO_2e (metric tons)
Engines 1-4	205,734,000	115,211	5,999
Dryer	16,526,871	9,255	482
Flare	26,600,529	14,896	776
Total	7,257 Metric Tons		

1. *Emission factors for CO_2 is 52.07 kg/MMBtu.*
2. *Global Warming Potential for CO2 is 1.*

4.3 GHG Emissions Related to Energy Production Alternatives

GHG emissions estimates will vary depending on the alternative energy production technology selected under Task 3 and the HSW quantities reviewed in TM 4. The alternatives that are being considered in the Solids Water Energy and Emissions Tracking (SWEET) model that would impact the GHG emissions compared to the current baseline include the following:

- Increasing the quantity of HSW to increase biogas production
- Gas conditioning and selective catalytic reduction (SCR) engine exhaust treatment to increase engine power output
- Upgrading biogas to renewable natural gas (RNG) and purchasing power from SDG&E
- Adding solar photovoltaics to the current engine operation

The GHG impact of each technology is discussed below.

- **Increased HSW for codigestion** will increase biogas production, which decreases anthropogenic GHG emissions but increases biogenic GHG emissions. Since biogas combustion does not count towards anthropogenic Scope 1 GHG emissions, producing additional biogas to offset natural gas consumption will lower EWPCF's anthropogenic GHG emissions.
- **Sending more biogas to the engines instead of the thermal dryer** will not have an impact on GHG emissions.
- **Upgrading biogas to RNG for pipeline injection** will increase Scope 1 and Scope 2 anthropogenic GHG emissions. EWPCF currently runs two 750-kW IC engines at full load, primarily on biogas. Sending all biogas to the pipeline will result in increasing natural gas fired combustion (Scope 1 anthropogenic) in the engines or purchasing electricity directly from SDG&E (Scope 2). Carbon dioxide in the tail gas from the biogas separation process also adds to Scope 1 GHG emissions. Transferring the product to the pipeline would not credit EWPCF with replacing an anthropogenic fuel with a biogenic fuel.
- **Large-scale and small-scale solar photovoltaics** will decrease Scope 2 GHG emissions. Solar PV panels do not emit GHGs and reduce the amount of energy that EWPCF would need to purchase from SDG&E or produce from the engines.

References

San Diego County Air Pollution Control District. New Source Review Requirements for Best Available Control Technology Guidance Document. June 2011.

The Climate Registry General Reporting Protocol for the Voluntary Reporting Program. Version 2.1, January 2016. http://www.theclimateregistry.org/wp-content/uploads/2014/11/General-Reporting-Protocol-Version-2.1.pdf

The Climate Registry Default Emission Factors. March 2017. http://www.theclimateregistry.org/wp-content/uploads/2017/05/2017-Climate-Registry-Default-Emission-Factors.pdf

Subregion Emissions - Greenhouse Gasses (eGRID2014v2), CAMX - WECC California eGRID subregion. https://www.epa.gov/sites/production/files/2017-02/documents/egrid2014_summarytables_v2.pdf

Attachment A: Revised Air Permit

November 2017

APCD
AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

COUNTY OF SAN DIEGO, AIR POLLUTION CONTROL DISTRICT
10124 OLD GROVE ROAD, SAN DIEGO, CA 92131
PHONE (858) 586-2600 FAX (858) 586-2601
www.sdapcd.org

Sectors: 2, E
Site Record ID: APCD1984-SITE-03370
Application Record ID: APCD2017-APP-004926

Startup Authorization Expires:
May 8, 2018

Encina Wastewater Authority
General Manager
6200 Avenida Encinas
Carlsbad CA 92011

EQUIPMENT ADDRESS
Encina Wastewater Authority
Douglas Campbell
6200 Avenida Encinas
Carlsbad CA 92011

STARTUP AUTHORIZATION

After examination of your Application APCD2017-APP-004926 for an Air Pollution Control District (hereinafter referred to as "the District") Authority to Construct and Permit to Operate for equipment located at 6200 Avenida Encinas Carlsbad CA 92011 in San Diego County, the District has decided on the following actions:

This Startup Authorization is granted pursuant to Rule 21 of the Air Pollution Control District Rules and Regulations for equipment to consist of:

Modification to conditions of Permits 000542, 000543, 000544, 000545 for four identical cogeneration engines: Caterpillar lean burn engine, model G3516, S/Ns 4EK05160, 4EK05161, 4EK05168, 4EK05175, fueled with digester gas and supplemented with natural gas, rated at 1306 bhp when fueled with digester gas and 1085 bhp when fueled with natural gas, each engine drives a 750 KW generator.

This Startup Authorization is issued with the following conditions:

1. When fueled with digester gas, the emissions of oxides of nitrogen (NOx) shall not exceed 47 parts per million by volume (ppmv), calculated as nitrogen dioxide at 15 percent oxygen on a dry basis.
2. When fueled with digester gas, the emissions of carbon monoxide (CO), shall not exceed 400 ppmv, calculated at 15 percent oxygen on a dry basis.
3. When fueled with natural gas, the emissions of oxides of nitrogen (NOx) shall not exceed 54 ppmv, calculated as nitrogen dioxide at 15 percent oxygen on a dry basis.
4. When fueled with natural gas, the emissions of carbon monoxide (CO), shall not exceed 390 ppmv, calculated at 15 percent oxygen on a dry basis.
5. Total digester gas and natural gas consumption for the four engines of Permit Nos. APCD2010-PTO-000542, APCD2010-PTO-000543, APCD2010-PTO-000544 and APCD2010-PTO-000545 shall not exceed 280 million standard cubic feet per year. Total natural gas consumption for all four engines shall not exceed 28 million standard cubic feet per year. Records demonstrating compliance with these limits shall be maintained on site and made available for inspection upon request. (NSR)
6. Total digester gas consumption for the four engines of Permit Nos. APCD2010-PTO-000542, APCD2010-PTO-000543, APCD2010-PTO-000544 and APCD2010-PTO-000545 shall not exceed 1 million standard cubic feet per day. Total natural gas consumption for all four engines shall not exceed 0.55 million standard cubic feet per day. Records demonstrating compliance with these limits shall be maintained on site and made available for inspection upon request. (NSR)
7. The owner or operator of each engine shall conduct periodic inspections of each engine and add-on control equipment to ensure that each engine is operated in compliance. Inspections shall be conducted at least once every 4,000 hours of operation or every six months, whichever occurs first. [R69.4.1]
8. The owner or operator of this engine shall conduct periodic maintenance of the engine and add-on control equipment, if any, as recommended by the engine and control equipment manufacturers or as specified by the engine servicing company's maintenance procedures. The periodic maintenance shall be conducted at least once each calendar year. (Rule 12, Rule 69.4.1)

9. This equipment shall be source tested once each permit year (annual source test) to demonstrate compliance with the emission standards contained in this permit. For the purposes of this permit, a permit year is the 12-month period ending on the last day of the permit expiration month. It is the responsibility of the permittee to schedule the source test with the District. The source test shall be performed or witnessed by the District. Each annual source test shall be separated by at least 90 days from any annual source test performed in a different permit year.
10. The engine shall be source tested annually to demonstrate compliance with the emission standards contained in this permit. Source testing shall be performed using the fuel with higher annual fuel consumption (in standard cubic feet) during the previous calendar year.
11. The owner or operator of the engine shall maintain records containing, at a minimum, the following: total daily and annual fuel consumptions of all four engines of Permit Nos. APCD2010-PTO-000542, APCD2010-PTO-000543, APCD2010-PTO-000544 and APCD2010-PTO-000545; records of periodic inspection and maintenance for the engines and control equipment, including dates inspection and maintenance were performed and copies of manuals of recommended maintenance procedures provided by the manufacturer.
12. All records shall be retained on site for at least three (3) years and made readily available to the District upon request.
13. Access, facilities, utilities and any necessary safety equipment for source testing and inspection shall be provided upon request of the Air Pollution Control District.
14. This Air Pollution Control District Permit does not relieve the holder from obtaining permits or authorizations required by other governmental agencies.
15. The permittee shall, upon determination of applicability and written notification by the District, comply with all applicable requirements of the Air Toxics "Hot Spots" Information and Assessment Act (California Health and Safety Code Section 44300 et seq.)

APCD
AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

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PHONE (858) 586-2600 FAX (858) 586-2601
www.sdapcd.org

Sectors: 2, E
Site Record ID: APCD1984-SITE-03370
Application Record ID: APCD2017-APP-004926

Startup Authorization Expires:
May 8, 2018

This authorization is for temporary operation of the above-specified equipment. This temporary Permit to Operate will remain in effect, unless withdrawn or modified by the District or a Permit to Operate is granted or denied.

This Startup Authorization shall be posted on or within 25 feet of the described equipment or maintained readily available at all times on the operating premises.

This Startup Authorization does not relieve the holder from obtaining permits or authorizations, which may be required by other governmental agencies.This Startup Authorization is not an authorization to exceed any applicable emission standard established by this District or any other governmental agency. This authorization is subject to cancellation if any emission standard or condition is violated.

Within 30 days after receipt of this Startup Authorization, the applicant may petition the Hearing Board for a hearing on any conditions imposed herein in accordance with Rule 25.

This Startup Authorization will expire on May 8, 2018, unless an extension is granted in writing.

If you have any questions regarding this action, please contact me at (858) 586 2747 or via email at camqui.nguyen@sdcounty.ca.gov.

Camqui Nguyen
Camqui Nguyen

Associate Engineer

CC: Compliance Division

Brown AND Caldwell

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Technical Memorandum

FINAL

Prepared for: Encina Wastewater Authority

Project title: Biosolids, Energy, and Emissions

Project no.: 150871.007

Technical Memorandum 7

Subject: Alternatives Development, Evaluation, and Selection

Date: May 17, 2018

To: Scott McClelland, Assistant General Manager

From: Scott Lacy, Project Manager

REGISTERED PROFESSIONAL ENGINEER
ALISON C. NOJIMA
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____
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Limitations:

This document was prepared solely for Encina Wastewater Authority in accordance with professional standards at the time the services were performed and in accordance with the contract between Encina Wastewater Authority and Brown and Caldwell dated June 28, 2017. This document is governed by the specific scope of work authorized by Encina Wastewater Authority; it is not intended to be relied upon by any other party except for regulatory authorities contemplated by the scope of work. We have relied on information or instructions provided by Encina Wastewater Authority and other parties and, unless otherwise expressly indicated, have made no independent investigation as to the validity, completeness, or accuracy of such information.

Table of Contents

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List of Abbreviations

°F	degree(s) Fahrenheit
AACE	American Association of Cost Engineering
BC	Brown and Caldwell
BCE	business case evaluation
BEE	Biosolids Energy and Emissions
Btu	British thermal unit(s)
BUS	biogas upgrading system
CH_4	methane
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
d	day(s)
DAF	dissolved air flotation
DG	digester gas
DGE	diesel gallon equivalent
dtpd	dry ton(s) per day
EWA	Encina Wastewater Authority
EWPCF	Encina Water Pollution Control Facility
FOG	fats, oils, and grease
ft^3	cubic foot/feet
gal	gallon(s)
GCS	gas conditioning system
hp	horsepower
hr	hour(s)
HSW	high-strength waste
IC	internal combustion
kW	kilowatt(s)
kWh	kilowatt-hour(s)
lb	pound(s)
LCFS	Low Carbon Fuel Standard
MMscf	million standard cubic feet
MW	megawatt(s)
NEM	net electric metering
NG	natural gas
NPV	net present value
O&M	operations and maintenance
PS	primary sludge
psig	pound(s) per square inch gauge
RDT	rotary-drum thickener
RFS	Renewable Fuel Standard
RIN	renewable identification number
RNG	renewable natural gas
scfm	standard cubic foot/feet per minute
SCR	selective catalytic reduction
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program
SSO	source-separated organics
SWEET	Solids Water Energy Evaluation Tool
THP	thermal hydrolysis process
TM	technical memorandum
TS	total solids
VS	volatile solids
VSR	volatile solids reduction
WAS	waste activated sludge

Executive Summary

The Encina Wastewater Authority (EWA) has undertaken a Biosolids Energy and Emissions (BEE) Plan that will be used to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed Process Master Plan. The BEE Plan provides a comprehensive analysis of all project elements including biosolids treatment, gas use, energy generation, and waste heat; addresses capacity limitations in the solids handling process at the Encina Water Pollution Control Facility (EWPCF); assesses which alternative is likely to be the most cost-effective and sustainable solution for EWA, and develops plans to move EWPCF toward lower energy costs, rate stability, greater overall sustainability, and reduced greenhouse gas emissions.

The approach of this work is to allow for consideration of all feasible alternatives, evaluation of all economic impacts, and consideration of non-cost risks in the development of defensible recommendations for future capital projects. This Technical Memorandum (TM) 7 presents the results of the end-to-end alternatives development, the evaluation process, and selection of a recommended alternative. Project alternatives were first screened in TMs 2 through 5, and shortlisted, via a fatal-flaw filter and an initial evaluation scoring for all solids processes, energy utilization alternatives, and waste heat recovery options. Alternatives that passed the screening criteria were then further analyzed using Brown and Caldwell's (BC's) Solids Water Energy Evaluation Tool (SWEET). TM 7 includes results from SWEET evaluation work, recommendation of a preferred alternative, and considerations for implementation of the recommended alternative.

The SWEET model is an Excel based computational spreadsheet developed over years from numerous designs for the quick and efficient analysis of numerous combinations of alternatives for solids processes, biosolids management and end use, co-digestion, and energy recovery. The tool evaluates process and energy demands and compares alternatives on an economic basis using capital and operating costs. The screened recommendations from the work described in TMs 2 through 6 were combined, evaluated with SWEET, and presented to EWA staff through multiple workshops. All alternatives were ranked based on the 20-year net present value (NPV). The key findings of the analysis are listed below:

- All alternatives benefited from increased digester gas (DG) production from co-digestion of organic high-strength waste (HSW). HSW is a general term that encompasses all imported waste streams that are typically highly digestible and contain high quantities of organics such as fats, oils and grease (FOG), liquid waste (i.e., brewery waste), and source separated organics or food waste.
- Improved thickening with rotary drum thickeners (RDT) provides multiple benefits, including increasing the capacity of the existing digesters, and reduced lifecycle costs compared to the existing thickening scheme.
- Installation of RDTs increases digester capacity and allows for implementation of a food-waste program.
- Upgraded DG for use as vehicle fuel, via pipeline injection, provides the greatest apparent return on investment compared to cogeneration systems or DG use in the solids dryer.

Through a comparison of NPV and site-specific constraints, five preferred alternatives were identified for detailed consideration in this TM. These alternatives include:

- Alternative 1: RDT-Mesophilic Digestion-Centrifuge Dewatering-One dryer-(Engines+Pipeline Injection)
- Alternative 2: RDT-Mesophilic Digestion-Centrifuge Dewatering-Two dryers-(Engines+Pipeline Injection)
- Alternative 3: RDT-Thermophilic 15-day Digestion-Centrifuge Dewatering-One dryer-(Engines+Pipeline Injection)
- Alternative 4: RDT-Thermophilic 15-day Digestion-Centrifuge Dewatering-Two dryers-(Engines only)
- Alternative 5: RDT-Thermophilic 10-day Digestion-Centrifuge Dewatering-Two dryers-(Engines+Pipeline)

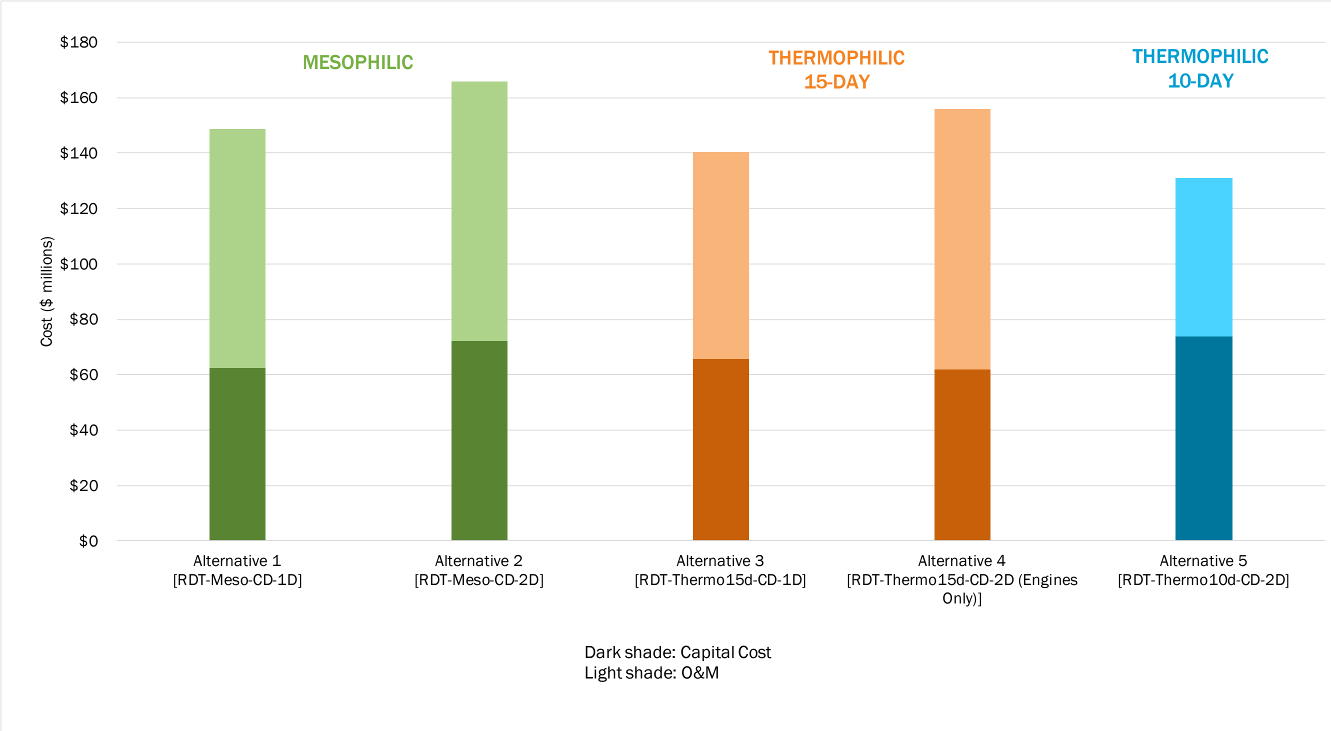

Figure ES-1. Overall NPV for top five alternatives

The economic evaluation of the top 5 alternatives indicated that the NPV results of these alternatives were similar and within the anticipated margin of accuracy for this level of analysis. Therefore, a consideration of non-cost criteria and risks was warranted in selection of a preferred alternative for implementation. Based on a non-cost criteria comparison, the Alternative 2 was identified as the preferred alternative for implementation. Mesophilic digestion was chosen as the preferred digestion process as it is well known and understood by plant staff. It provides enough digester gas to meet EWA's energy recovery goals and can be converted to a thermophilic digestion process any time in the future. Continued operation of the dryer and installation of a second dryer in the future would greatly reduce truck traffic and odors within the plant. It provides end-use resiliency through a Class A pelletized product. Energy recovery was identified as a critical component of the project implementation, and pursuit of multiple energy recovery options is recommended to adopt the best approach for EWA. DG upgrading for pipeline injection and increased cogeneration output are both contingent upon approval from outside agencies. For pipeline injection, the EWA must work toward an interconnection agreement with the natural gas (NG) utility, San Diego Gas & Electric (SDG&E). This process can take up to 2 years and may uncover unforeseen costs or project requirements. For increased cogeneration output, EWA must first work toward another air permit revision with the San Diego Air Pollution Control District, which requires gas conditioning and exhaust treatment. In addition, EWA must develop a net electric metering (NEM) tariff with SDG&E. This will likely require a new interconnection agreement.

Because both primary alternatives (pipeline injection and increased cogeneration output) require work with outside agencies (and associated risks), BC recommends that EWA pursue both options in parallel. EWA should pursue a revised air permit while initiating conversations with SDG&E to perform initial steps for NG pipeline interconnection as well as NEM. These discussions are the first step in determining whether an alternative remains viable. Total project costs for these DG alternatives range from $3 million to $22 million, with grant opportunities available for pipeline injection.

Solids process upgrades were also considered in this evaluation. Installation of the RDTs will increase capacity in the existing mesophilic digesters, deferring the need for future digester capacity until 2038 (with the second dryer in operation by 2026). Other processes, such as the thermal hydrolysis process (THP), were considered to identify economic benefits related to the solids dryer capacity and the need for a second dryer; however, these processes were found to have higher economic cost relative to other options. With increased capacity for HSW and the desire to develop a reliable HSW program, it is recommended that the existing high-strength waste receiving equipment be upgraded or a new receiving station installed to improve waste receiving and process control in the future. These expansions should include improvements to facilitate safe and dependable truck traffic through the plant for HSW deliveries.

Digester improvements in terms of upgrading existing mixing systems on Digesters 4, 5, and 6 along with structural modifications will need to be addressed immediately for continued operation. Until the installation of a second dryer, it is recommended that improvements to the Class B loadout are provided to improve reliability of the operation and reduce odor impacts from the plant. This includes upgrades to the existing centrifuges and mechanical piping modifications to allow for simultaneous operation of dryer and loadout of Class B biosolids.

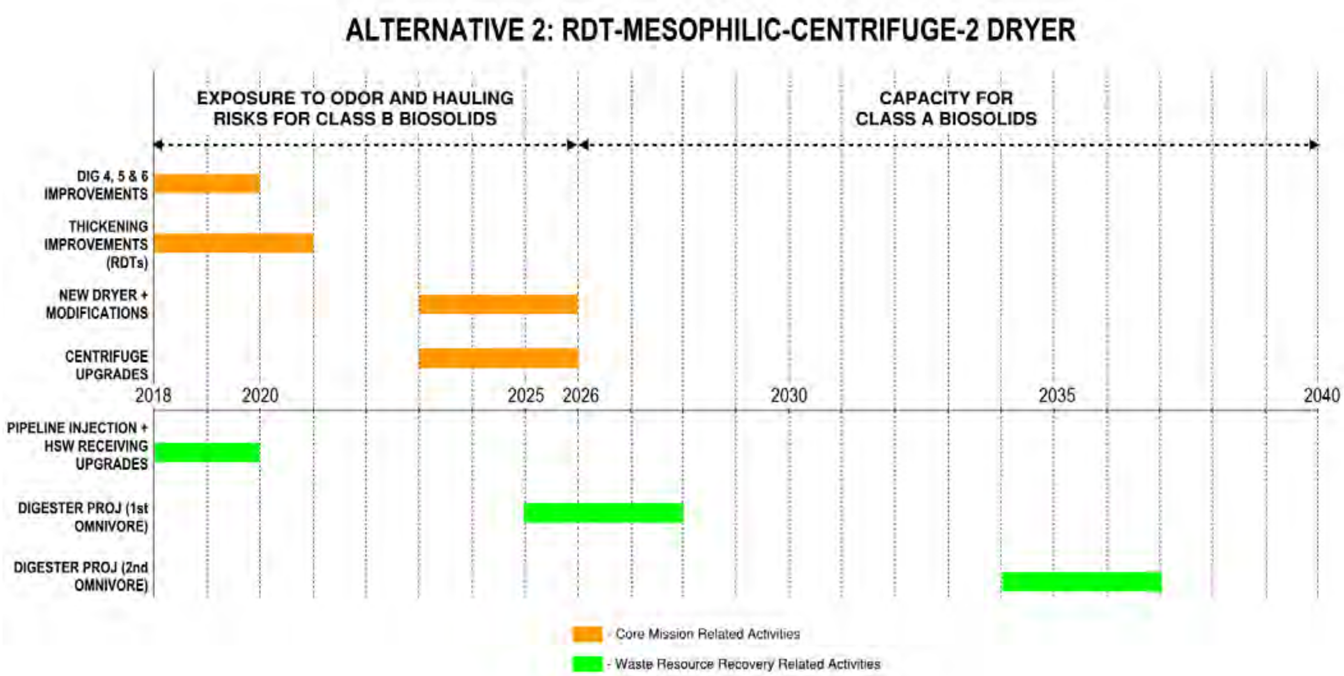

Figure ES-2. Implementation schedule for preferred alternative

BC recommends the following based on economic and non-economic evaluation:

- Implement common project elements such as thickening improvements (RDTs), digester improvements, HSW receiving, and Class B truck loadout improvements. Continue operation of mesophilic digestion until capacity or energy recovery needs change.
- Plan for implementation of a second dryer.

- Consider construction of gas upgrading to pipeline to capitalize on market opportunities and offset costs for needed gas conditioning equipment. First, a capacity analysis should be performed with SDG&E to determine the location of the nearest pipeline and the feasibility of accepting biomethane. If the capacity analysis indicates SDG&E can accept biomethane, EWA may pursue a private-public partnership arrangement to deliver the project (including a HSW receiving facility) without requiring a capital outlay from EWA.
- Pursue a new air permit with carbon monoxide (CO) catalyst to increase engine output. If a new air permit can be obtained to allow additional fuel usage in the engine, EWA should initiate discussions with SDG&E for NEM electrical rate schedule to potentially lower power bills and export power.
- Continued use and operation of the cogeneration system is recommended. Any measures that increase permitted cogeneration energy production or reduce the cost of electricity should be pursued. An NEM tariff would reduce electric utility costs by eliminating the standby charge—it would also allow for power export and simplify (or eliminate) the EWPCF's current grid isolation practice. Any air permit revisions to allow for greater DG utilization and energy output are recommended. The addition of upstream DG conditioning and exhaust treatment using a CO catalyst appears to be the best pathway. Any changes that trigger more stringent exhaust treatment measures, such as selective catalytic reduction or continuous emissions monitoring systems, should be avoided.
- Installation of a second dryer was identified as the preferred alternative for continued solids processing. This alternative had a comparable economic impact relative to the other top-rated alternatives and allowed for the best non-cost considerations, including reduced risk management related to biosolids management, reduced truck traffic, reduced plant odors, and maximized use of existing infrastructure. However, the installation of a second dryer can be deferred by operating a Class B truck loadout until other necessary improvements are made to the process (until 2026).
- While the second dryer train does not perform as well on an NPV basis in nearly all alternatives, there are non-cost and practical reasons to implement a second train. The timing of bringing this second train on line to realize the most cost savings will be a very important decision for EWA.

Section 1: Introduction

The Encina Wastewater Authority (EWA) has undertaken a Biosolids Energy and Emissions (BEE) Plan that will be used to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed Process Master Plan. The BEE Plan has several goals:

- Provide a comprehensive analysis of all project elements including biosolids treatment, gas use, energy generation, and waste heat.
- Address capacity limitations in the solids handling process at the Encina Water Pollution Control Facility (EWPCF).
- Assess which alternative is likely to be the most cost-effective and sustainable solution for EWA.
- Move EWPCF toward lower energy costs, rate stability, and greater overall sustainability.
- Reduce greenhouse gas emissions.

1.1 Purpose

This Technical Memorandum (TM) 7 presents the results of the end-to-end alternatives development, the evaluation process, and selection of a recommended alternative. Project alternatives were first screened in TMs 2 through 5, and shortlisted, via a fatal-flaw filter and an initial evaluation scoring. Alternatives that passed the screening criteria were then further analyzed using Brown and Caldwell's (BC's) Solids Water Energy Evaluation Tool (SWEET). TM 7 includes results from SWEET evaluation work. TM 7 is preceded by the following TMs as part of the BEE project:

- **TM 1**: Baseline Energy Profiles and Projections
- **TM 2**: Technology Evaluations for Biosolids Handling
- **TM 3**: Technology Evaluations for Alternative Power Production
- **TM 4**: Technology Evaluations for Biogas Production
- **TM 5**: Technology Evaluations for Waste Heat
- **TM 6**: Air Emissions

1.2 SWEET Model

The alternatives analysis uses BC's SWEET model, which tracks volatile solids (VS), inert solids, and water through potential process alternatives and considers energy required to power/heat those processes and forecast energy production and material recovery. It also allows energy balances to be compared with integration of multiple feedstocks, and it allows the carbon footprint of each alternative to be determined. Two notable advantages of SWEET are its ability to evaluate alternatives in real time during workshops and its transparency on all of the factors used.

The SWEET model provides the ability to develop a life-cycle economic analysis for end-to-end alternatives over a specific planning period. A business case evaluation (BCE) consisting of capital costs, operations and maintenance costs, repair and replacement associated with each alternative, and environmental attributes can be generated by running the SWEET model.

BC's approach to developing the SWEET model started with two separate models, one for energy alternatives and one for the solids alternatives. These two models were evaluated separately to determine trends and patterns that would then facilitate screening and/or adding appropriate alternatives into a combined SWEET model. The results from the individual SWEET models for energy and solids are referred to as Round 1A results; the results from the first comparison of the combined SWEET model are referred to as Round 1B results.

The results from Round 1A were discussed with EWA in two weekly progress conference calls and input from that call provided a basis for developing the end-to-end alternatives for the combined Round 1B model. Results from the combined Round 1B model were presented at Workshop 4 held in December 2017. Discussions from that workshop provided basis for screening out many of the alternatives evaluated in Round 1B and ultimately led to evaluating five top alternatives for Round 2 of the SWEET model.

Section 2: Development of SWEET Model

The SWEET model is an Excel based computational spreadsheet based on numerous designs for the quick and efficient analysis of numerous combinations of alternatives for solids processes, biosolids management and end use, co-digestion, and energy recovery. The tool develops process and energy models and compares alternatives on an economic basis using capital and operating costs. This section describes the process used to develop solids stream alternatives for this BCE, including process assumptions applied, Round 1A end-to-end alternatives, cost assumptions, and solids stream comparison themes.

2.1 Process Assumptions

The technologies and options evaluated for each major unit process, along with corresponding process assumptions, are described in this section. Each end-to-end alternative used one or more of the options listed here.

2.1.1 Baseline Solids Model

The baseline model describing the solids process at EWPCF based on plant data from 2015 to 2017 was built using the calibrated mass balance detailed in TM 1. The results of the mass balance were captured in SWEET in a baseline model, which served as a basis for comparison to all end-to-end alternatives.

Each input stream and process is captured in SWEET using a module, where process and energy inputs are provided, and the model performs cumulative solids and power calculations. A single SWEET model constitutes a linear stream of several input and process modules, with all calculations occurring cumulatively. The baseline model was built using 2-year average waste activated sludge (WAS); primary sludge (PS); and fats, oils, and grease (FOG) loads as feedstock inputs, with WAS undergoing thickening using dissolved air flotation (DAF). These three loads were applied as inputs to a mesophilic digestion module, where volatile solids reduction (VSR) was determined by applying a load-weighted composite of assumed VSR for each of the three feedstocks. The digested sludge was fed to a centrifuge module for dewatering, followed by either the production of Class B dewatered cake, or thermal drying to produce Class A pellets.

2.1.2 Feedstock Assumptions

The feedstocks assumed as initial conditions for the evaluation of all alternatives are shown in Table 2-1. These values, based on the mass balance detailed in TM 1, were applied to 2017 loads. The projection of loads for future years through 2040 was based on the growth rate determined in the 2015 *Process Master Plan*. The high-strength waste (HSW) loads in terms of FOG were determined based on historical data from EWA and kept static regardless of the alternative under evaluation. Additional HSW loads applied were based on maximizing digester capacity for each digestion alternative under consideration. The excess gas can be utilized for pipeline injection, power generation, the existing solids dryer, or a combination of each.

Table 2-1. Summary of Feedstocks				
Feedstock	Input Flow (gpd)	Input Load, 2018 (lb/d)	TS (percent)	VS (percent)
PS (thickened)	138,900	47,500	4.1	87
WAS (thickened)	705,000	29,400	0.5	80
FOG (as received)	8,720	4,000	5.5	80
Future HSW Options				
SSO, mesophilic digestion	30,000[b]	30,000	12	85
SSO, 10-day thermophilic digestion	80,000[b]	30,000	12	85
SSO, 15-day thermophilic digestion	50,000[b]	50,000	12	85
Conventional THP	80,000[a]	80,000	12	85
Conventional THP, Cambi B2-4 reactors	50,000[a]	80,000	12	85
WAS-only THP	30,000[a]	30,000	12	85

a. *Year implemented would depend on phasing of digester projects over 20-year planning period.*

2.1.3 Thickening Process Assumptions

The thickening technologies considered in all alternatives were either the existing dissolved air flotation thickeners (DAFTs) or new rotary-drum thickener (RDT) units. All DAFTs were assumed to thicken the WAS stream only, as occurs with current thickening operation. Table 2-2 summarizes the major process assumptions made for DAFTs in the SWEET model. RDT thickening was evaluated as a potential upgrade technology, owing to its higher energy efficiency and its smaller unit footprint compared to DAF thickening. If RDT thickening is implemented, it is assumed to be used to co-thicken WAS and PS streams. Table 2-2 summarizes the major assumptions made for thickening processes in the SWEET model.

Table 2-2. DAF Thickening Process Assumptions			
Parameter	Unit	DAF	RDT
Stream thickened	-	WAS	WAS and PS
Solids capture	-	95%	95%
Thickened sludge TS	-	5.6%	6.0%
Unit loading	lb/d	45,000	25,200
Process energy consumption	hp	Variable [a]	8

a. *Process energy consumption is calculated using input stream loading in a linear relationship with power, based on historical data.*

2.1.4 Thermal Hydrolysis Process Assumptions

The thermal hydrolysis process (THP) was evaluated as a potential technology to enhance existing facility capacity and cake quality, obviating the need for subsequent thermal drying. The THP process involves the use of pre-dewatering, followed by dilution, to bring solids content to a target of about 16.5 percent for reactor feed. Pre-dewatering for THP alternatives assumed the use of existing dewatering centrifuges, while final dewatering would be accomplished using other dewatering technology options. The thermal hydrolysis reactors may be sized on solids loading, and several THP alternatives were based on differences in size and service number of THP reactors. The THP process is followed by standard mesophilic digestion, where the hydrolyzed sludge is diluted to ensure stable digestion operation.

THP was applied to two process streams, spanning several alternatives: conventional, or Class A THP, where all feed streams are fed to THP reactors, and WAS-only THP, where only the WAS stream undergoes THP, and is fed to the digesters along with the other feed streams. Table 2-3 summarizes the major assumptions made for digestion processes in the SWEET model. The Cambi THP system was used as the assumed THP system for evaluation purposes in this project.

Table 2-3. THP Process Assumptions

Parameter	Unit	Conventional THP	WAS-only THP
Streams processed	-	WAS, PS, SSO, FOG	WAS
Pre-dewatering solids capture	-	95%	95%
Pre-dewatered sludge TS	-	20%	18%
Pre-dewatering energy consumption	hp	225	125
THP feed solids content	-	16.5% (avg.)	16.5% (avg.)
THP steam demand	lb/lb TS	0.9	0.9
Heat requirement for steam generation	Btu/lb steam	1,197	1,197
THP boiler efficiency	-	85%	85%
THP operation temperature	°F	302	302
THP reactor process energy consumption	hp	100	50

2.1.5 Digestion Process Assumptions

Two major digestion processes were assumed in all alternatives: mesophilic digestion, which is the current process, and thermophilic digestion. Thermophilic digestion was evaluated at 10- and 15-day retention times. VSR in each alternative was calculated as a load-weighted composite of VSR assumptions for each feed stream, as detailed in Table 2-4. To summarize, VSRs for mesophilic digestion were assumed based on historical plant data received from EWA. VSRs for thermophilic digestion at 10-day retention time were assumed to be similar to those for mesophilic digestion. VSRs for 15-day thermophilic digestion were assumed to be higher for WAS and PS streams. Finally, in cases where THP is applied, VSRs are assumed to increase in downstream mesophilic digestion for those feed streams that are hydrolyzed.

Additionally, digestion enhancements to increase capacity or improve cake quality were evaluated in some alternatives, like recuperative thickening with mesophilic digesters, and the use of Class A batch tanks with thermophilic digesters at 10-day retention times. Table 2-4 summarizes the major assumptions made for digestion processes in the SWEET model.

Table 2-4. Digestion Process Assumptions					
Parameter	Unit	Mesophilic	Thermophilic, 10-day	Thermophilic, 15-day	Post-THP Mesophilic Digestion
Operation temperature	°F	97	131	131	97
PS VSR	-	65%	68%	68%	68%
WAS VSR	-	47%	47%	52%	55%
FOG VSR	-	90%	90%	90%	90%
SSO VSR	-	80%	80%	80%	80%
Gas production	ft^3/lb VS removed	18	18	18	18
Energy consumption	hp	Variable [a]	Variable [a]	Variable [a]	Variable [a]
Shell heat loss	-	5%	10%	10%	5%

a. *Energy consumption is calculated using input stream loading in a linear relationship with power, based on historical data.*

2.1.6 Dewatering Process Assumptions (Digested Biosolids)

Three major technologies were evaluated for dewatering, including the existing centrifuges, belt filter presses, and screw presses. Each of these technologies was assumed to dewater all digested sludge. It should be noted that peak day loads that may have been applied for the sizing of processes upstream of digestion may not apply to dewatering, because some equalization is provided by digestion and digested sludge storage, using an existing smaller digester tank. Table 2-5 summarizes the major assumptions made for dewatering processes in the SWEET model.

Table 2-5. Dewatering Process Assumptions					
Parameter	Unit	Centrifuge	Belt Filter Press	Belt Filter Press (THP) [a]	Screw Press
Unit loading	lb/d	72,000	48,000	48,000	48,000
Solids capture	-	95%	90%	95%	90%
Dewatered cake TS	-	22%	25%	30%	25%
Energy consumption	hp	Variable [b]	Variable [c]	Variable [c]	35

a. *Belt filter presses are assumed to perform final dewatering on all THP alternatives.*

b. *Centrifuge energy consumption is calculated using input stream loading in a linear relationship with power, based on historical data.*

c. *Belt filter press energy consumption is calculated as 50% of corresponding centrifuge energy consumption.*

2.1.7 Thermal Drying Assumptions

EWPCF currently operates a single thermal dryer to produce dried pellets from dewatered cake. The dryer is operated on a 14-day cycle, where it runs for 11 days and is shut down for routine maintenance during the 3 remaining days. A review of historical data (TM 1) showed some periods of extended dryer outage, when dewatered cake was hauled off site as a Class B product. Of total annual end use production, about 3.6 percent was hauled as cake.

Among the options considered in all alternatives in connection with solids end use were (1) adding a second dryer to add capacity; (2) continuing to use a single dryer; or (3) using no dryer. In the case of using two dryers, it was assumed that cake would not typically be hauled off site, because of the unlikeliness of both dryers being out of service at the same time. When a single dryer is used, the assumption was made that about 3.6 percent of solids produced continued to be hauled off site as cake on an annual average basis. Alternatives that removed thermal drying completely used THP upstream. The combination of THP/digestion plus thermal drying was deemed to produce a less desirable final product, and the assumption was made that all dewatered cake from THP sludge would be hauled off site as a Class A Cake product. Table 2-6 summarizes the major assumptions made for thermal drying in the SWEET model.

Table 2-6. Thermal Drying Process Assumptions

Parameter	Unit	Two Dryers	One Dryer	No Dryer
Unit loading	dtpd	28.5 [a]	18 [b]	-
Dried pellet TS	-	94%	94%	-
Heat requirement	BTU/lb	1,450	1,450	-
Energy consumption	hp	Variable [c]	Variable [c]	0

a. *Capacity downrated by 5%.*

b. *Based on 14-day dryer operation cycle.*

c. *Dryer energy consumption is calculated using input stream loading in a linear relationship with power based on historical data.*

2.1.8 Baseline Energy Model

The baseline model describing the energy process was first built upon the solids baseline alternative using existing dissolved air flotation thickening, thermal drying, and centrifugal dewatering. Unlike the solids baseline, the energy baseline assumes a thermophilic digestion process, which allows for a higher organic loading rate (i.e., addition of HSW) and the associated increase in biogas production in comparison to mesophilic digestion for a relatively low capital investment. Assuming a greater biogas production provided better financial differentiation between the biogas utilization alternatives. An additional set of baseline scenarios using mesophilic digestion were also investigated.

Each input stream and process is captured in SWEET in a similar process as described in Section 2.1.

2.1.9 Air Permit Restrictions

In November 2017, EWA received a modified air permit for the four existing 750-kilowatt (kW) internal-combustion (IC) engines. The previous permit allowed for a total annual consumption of biogas and natural gas up to 224 million standard cubic feet (MMscf), with a maximum of 24 MMscf of natural gas; the revised permit allows up to 280 MMscf of biogas and natural gas, with a maximum of 28 MMscf of natural gas. Modifying the air permit allows EWA to operate approximately one additional 750 kW engine on a 50 percent load, bringing the total permitted power production up to the current EWPCF demand estimated in TM 1.

Figure 2-1 illustrates the various achievable power outputs for a given biogas and natural gas (NG) volume input within permit restrictions. Lines indicating the permit maximum NG annual usage (y-axis) and total gas usage (x-axis) outline the allowable ranges of biogas and NG usage. There exists a unique combination of each one's annual average flow rates that maximizes engine power output. This point is indicated by the star on Figure 2-1 and it corresponds to a value of 1.92 megawatts (MW), assuming a 34.5 percent engine electrical efficiency. For the scenario in which EWPCF electricity demand is below 1.92 MW, the range of flow rate combinations would yield an engine output equal to EWPCF demand. Depending on whether biogas or NG use is prioritized, the gas use profile can be preferentially adjusted along the desired power output line.

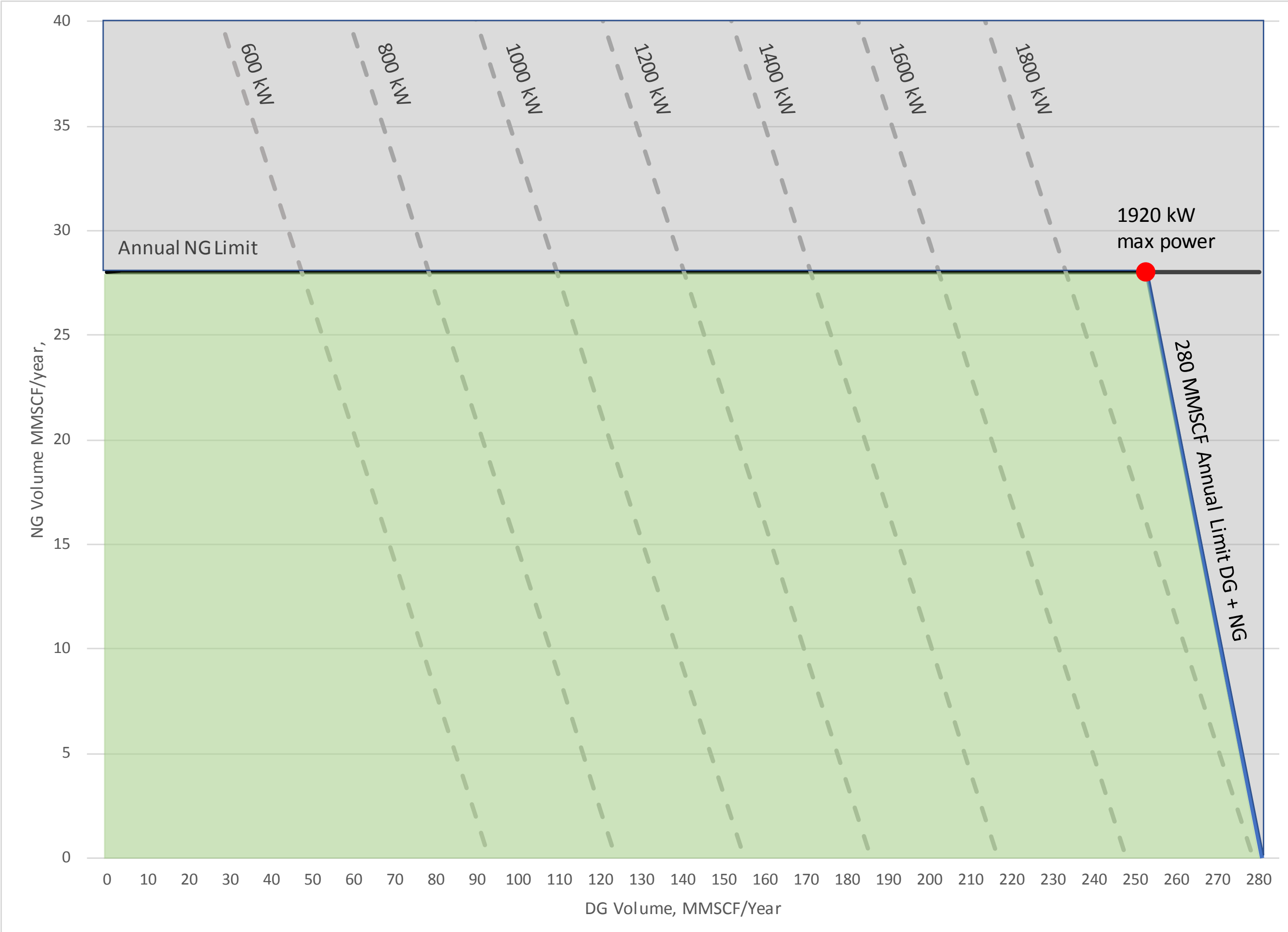

Figure 2-1. Several engine output lines are plotted for combinations of biogas and NG usage

The permitted values of 28 MMscf/year of natural gas and 280 MMscf/year of combined biogas and natural gas are plotted and outline the limits of engine power production. The green area represents possible combinations of DG and NG use.

These gas use restrictions and optimization strategies were applied to the energy alternatives to maximize electricity generation, pipeline injection of upgraded biogas, or both.

2.1.10 Internal-Combustion Engine Assumptions

IC engines produce power to offset purchased energy and reduce peak demand and non-coincident demand charges. IC engines, however, are subject to standby charges based on installed nameplate capacity. IC engines can operate on biogas, natural gas, or both up to the amount permitted by the San Diego Air Pollution Control District. The production capacity and ultimate power generation of each IC engine module in SWEET was dictated by the air permit and the end-to-end alternative goal (maximize electricity generation or pipeline injection). Table 2-7 summarizes the major process assumptions used for the IC engine units in the SWEET model. Although the installed engine capacity is 2.25 MW, the permit limit of 1.92 MW calculated in Section 2.1.9 was the maximum power output used in the SWEET model. One alternative explores the case where EWA pursues a new air permit, which would likely require engine exhaust treatment, so that EWPCF can run a large-scale cogeneration operation up to 5 MW and export power to its member agencies.

Table 2-7. IC Engine Process Assumptions		
Parameter	Unit	Value
Engine electrical efficiency: existing engines	-	34.5%
Engine electrical efficiency: new engines Alternative 12S	-	39%
Thermal efficiency	-	40%
Installed capacity	MW	2.25
NG lower heating value	Btu/ft^3	909
DG lower heating value	Btu/ft^3	560
Process energy consumption	hp	Variable [a]

a. *IC engine energy consumption is calculated using input stream loading in a linear relationship with power, based on historical data.*

Selective catalytic reduction (SCR) is an IC engine exhaust treatment technology that greatly reduces nitrogen oxides emissions and is discussed in TM 4. SCR was originally considered as an alternative for the existing engines to unlock additional engine capacity, but the revised permit achieved the same goal without capital investment. However, SCR is explored in several alternatives in addition to other process changes where engines operate on natural gas.

2.1.11 Gas Conditioning Assumptions

Several alternatives include the addition of a gas conditioning system (GCS) that removes moisture, hydrogen sulfide, siloxanes, and potentially ammonia from digester gas (DG) prior to utilization. While the GCS requires upfront capital costs, the IC engines, solids dryer, and potential microturbines (described below) benefit from cleaner gas being delivered to the equipment. Table 2-8 lists capital and project cost assumptions related to gas conditioning that were used in developing the net present value (NPV).

Table 2-8. Gas Conditioning Cost Assumptions		
Cost Element	Capital Cost	Project Cost
GCS: 650 scfm	$3.3M	$4.3M
GCS: 800 scfm	$3.7M	$4.8M
GCS: 1,200 scfm	$4.8M	$6.2M

2.1.12 Microturbine Assumptions

The installation and use of microturbines increase onsite power production while working around the existing air permit. Microturbines can utilize any digester gas beyond what the current air permit allows the engines to use and are a low-emission technology. Gas conditioning and compression up to 80 pounds per square inch gauge (psig) is required upstream of the microturbines. Table 2-9 lists the process assumptions for microturbine modules in the SWEET model.

Table 2-9. Microturbine Process Assumptions		
Parameter	Unit	Value
Microturbine electrical efficiency	-	31%
Thermal efficiency	-	21%
Installed capacity	MW	0.40
Microturbine uptime	-	90%
Process energy consumption	hp	Variable [a]
Capital cost	$	4.0M
Project cost	$	5.2M

a. *IC engine energy consumption is calculated using input stream loading in a linear relationship with power, based on historical data.*

2.1.13 Biogas Upgrading and Pipeline Injection

A biogas upgrading system (BUS) includes the same gas conditioning as conventional treatment, in addition to carbon dioxide (CO_2) and methane (CH_4) separation to produce renewable natural gas (RNG) suitable for sale via utility pipeline injection. This system achieves the highest value of biogas if environmental attributes such as renewable identification numbers (RINs) and Low Carbon Fuel Standard (LCFS) credits are in place. The Renewable Fuel Standard (RFS) RINs and LCFS programs are previously discussed in TMs 4 and 8. The pipeline injection alternatives can be standalone or coupled with engine and solar options to offset the amount of power that EWA purchases. BUSs in SWEET were either 800 or 1,400-standard-cubic-foot per minute (scfm) capacity systems. When all biogas is sent to the pipeline, it is assumed that a boiler will provide heat for the digesters. It is more economical to fuel the hot water boiler with natural gas than digester gas because digester gas is significantly more valuable as a renewable fuel. Table 2-10 lists the process assumptions for the biogas upgrading and pipeline injection processes and Table 2-11 summarizes the cost assumptions for the various alternative sizes.

Table 2-10. Biogas Upgrading System Process Assumptions		
Parameter	Unit	Value
System uptime	-	95%
CH_4 recovery	-	99.5%
Installed capacity	scfm	Varies depending on HSW quantity and alternative
Ethanol LHV	Btu/gal	76,330

Table 2-11. Pipeline Injection Cost Assumptions		
Cost Element	Capital Cost	Project Cost
BUS: 1,400 scfm	$16.9M	$22.0M
BUS: 1,200 scfm	$16.3M	$21.2M
BUS: 800 scfm	$13.0M	$16.9M
BUS: 650 scfm	$11.7M	$15.3M
BUS: 200 scfm	$7.8M	$10.2M

Note: These costs assume interconnection fees are included.

2.1.14 Solar

Solar panels installed over the existing equalization basins or aeration basins, or in a 5-acre lot, can provide supplemental power for EWPCF when the IC engines reach permitted capacity or when digester gas is being utilized for pipeline injection instead of onsite power generation. Several SWEET alternatives incorporate solar power in one of these three areas using power generation and cost assumptions listed in Table 2-12. The "capacity factor" listed below refers to the ratio of the expected actual average power output to the installed nameplate capacity of the solar panels.

Table 2-12. Solar Process Assumptions		
Parameter	Unit	Value
Equalization basin installed capacity	MW	0.13
Aeration basin installed capacity	MW	0.40
5-acre lot installed capacity	MW	0.80
Capacity factor	-	18.3%

2.1.15 Net Electric Metering

Several SWEET alternatives result in EWPCF electricity production that exceeds EWPCF demand. This excess electricity can be sold to the utility for revenue via net electric metering (NEM). Economic assumptions of this process are described in Section 2.2.1. An assumed project cost of $2 million is assumed for NEM upgrades at EWPCF.

Switching to an NEM tariff would eliminate the current standby charge. This is a significant portion of EWA's electric bill.

2.1.16 Carbon Monoxide Catalyst

Installing a carbon monoxide (CO) catalyst would provide an opportunity for EWA to pursue a revised air permit. The current permit limits the quantity of gas that can be combusted in the engine based on a CO emissions requirement. By installing a CO catalyst on the engine exhaust, CO emissions can be reduced to a level at which a revised air permit allows for additional gas to be combusted. A robust gas conditioning system is required upstream of the engine to remove siloxanes to non-detect levels and prevent catalyst fouling.

2.2 Cost Assumptions

The following section describes the various assumptions made on capital costs, operating costs and repair and replacement for SWEET life-cycle cost analysis.

2.2.1 Capital Costs

Capital costs were estimated using several sources. Detailed cost estimating was not performed, but in many cases available costs from other appropriate biosolids projects in neighboring areas of Southern California were used. Capital cost estimates in this analysis are considered less reliable than a Class V estimate as defined by the American Association of Cost Engineering (AACE) (minus 50 percent, plus 100 percent). As such, capital cost estimates in this document should be used for comparison only, and not be used for capital budgeting.

Capital costs for each solids/energy option were tabulated based on the following sub-categories:

1. Civil and Structural Costs
2. Demolition Costs
3. Mechanical Costs (Included allowances for mechanical piping and installation)
4. Electrical, Instrumentation & Control Costs (Assumed to be 25 percent of mechanical equipment costs)

Project costs were then calculated by applying the following mark ups on the capital costs:

1. Contingency= 30 percent
2. Engineering and Administration= 20 percent

The following Table 2-13 represents the capital costs for the biosolids alternatives.

Table 2-13. Capital Costs Assumptions for Biosolids Alternatives

Cost Element	Capital Cost	Project Cost
Systems		
DAF Rehabilitation (Alts assuming DAFs)	$3.6M	$5.6
RDT (WAS only)	$4.6M	$7.2M
RDT (Co-thickening)	$5.96M	$9.3M
Digester Improvements (Dig 4, 5 & 6)	$2.39M	$3.72M
HSW Receiving Upgrades	$0.5M	$0.78M
New HSW Receiving Station	$3M	$4.68M
Digester (Omnivore I)	$3.7M	$5.77M
Digester (Omnivore II)	$3.7M	$5.77M
Thermophilic 15-day Upgrades	$2.5M	$3.9M
Thermophilic 10-day Upgrades	$3.69M	$5.76M
Centrifuge Upgrades	$3M	$4.68M
Existing Dryer Modifications	$2M	$3.12M
New Second Dryer (Includes dryer modifications)	$14.52M	$22.65M
Class B Truck Loadout and Odor Control	$10M	$15.6M
Truck Traffic Improvements	$1.5M	$2.34M

The following Table 2-14 represents the capital costs for the energy alternatives.

Table 2-14. Capital Costs Assumptions for Energy Alternatives

Cost Element	Capital Cost	Project Cost
Systems		
GCS - 650 scfm	$3.3M	$4.3M
GCS - 800 scfm	$3.7M	$4.8M
GCS - 1200 scfm	$4.8M	$6.2M
SCR	$3.0M	$3.9M
CO Catalyst	$0.7M	$1.0M
Microturbines w/ Compression	$4.0M	$5.2M
BUS - 1400 SCFM	$17.0M	$22.0M
BUS - 1200 SCFM	$16.3M	$21.2M
BUS - 800 SCFM	$13.0M	$16.9M
BUS - 650 SCFM	$11.7M	$15.3M
BUS - 200 SCFM	$7.8M	$10.2M
Solar Installation - 130 kW	$0.4M	$0.5M
Solar Installation - 400 kW	$0.8M	$1.0M
Solar Installation - 800 kW	$1.5M	$2.0M
Net Metering	$1.5M	$2.0M

2.2.2 Operating Costs

The life-cycle cost evaluation of alternatives includes estimates of both operating costs and capital costs. To the best degree possible, operating cost estimates reflect the actual operating parameters and unit costs at EWPCF. Information was requested and received from EWA operations staff for labor; materials-chemicals; utilities such as water, natural gas (NG), and electricity; and biosolids trucking/disposition costs. Table 2-15 summarizes the basis of operations and maintenance (O&M) costs used. In some cases, future estimates are made for these products or situations.

Table 2-15. Assumptions on Operations and Maintenance Costs

Cost Element	Value in Model
Electricity used, $/kWh	$0.09
Exported electricity produced, $/kWh	$0.04 (future estimate)
NG unit cost, $/therm	$0.31
Potable water, $/gal	$0.013
Pellets disposition, $/wet ton	$16.00
Class B cake hauling, $/wet ton	$48.00
Class A cake hauling, $/wet ton	$41.00 (future option estimate)

Table 2-15. Assumptions on Operations and Maintenance Costs

Cost Element	Value in Model
Class A cake composting, $/wet ton	$60.00 (future option estimate)
Polymer, $/lb	$1.20
Labor: maintenance, $/hr	$69.63
Labor: operations, $/hr	$69.79
FOG tipping fee, $/gal	$0.04
SSO tipping fee, $/gal	$0.04
Electricity cost, $/kWh	$0.09
Exported electricity price ($/kWh)	$0.04
NG unit cost ($/therm)	$0.31
Standby power charge, $/kW	$14.20
Current standby power charge, annual	$391,068
Current non-coincident demand charge, annual	$255,923
Current non-coincident demand charge, $/kW	$24.51
Peak demand, $/kW	$7.56
Renewable Fuel Standard RINs, D3, $/RIN	$2.00
LCFS: DG $/DGE	$0.70
SGIP, $/watt	$1.20
Boiler O&M: annual (without SSO)	$12,000
Boiler O&M: annual (with HSW)	$15,000
Cogen O&M: no gas conditioning, $/kWh	$0.03
Cogen O&M with gas conditioning, $/kWh	$0.015
Gas conditioning O&M, $/kWh	$0.005
SCR O&M, $/kWh	$0.015
CNG O&M, $/MMscf	$540

Additionally, incentivized credits for producing RNG are based on current trading values as of November 2017. Broker fees for bundling and selling the RINs and LCFS credits typically range from 15 to 20 percent of the sale. To account for broker fees, the RINs were assigned a lower trading value in the D5 advanced biofuels category; D3 cellulosic RINs currently trade for up to three times the value of D5 RINs, which are generated from HSW in comparison to the D3 RINs, which are generated from municipal wastewater. The RFS and LCFS programs are currently expected to last through 2022 and 2030, respectively. These programs are expected to continue after the published program dates, but are not guaranteed; therefore, the SWEET evaluation conservatively assumes the current program durations.

The life-cycle cost analysis (BCE) was performed over a 20-year period that included a 4.0 percent escalation rate and a 3.5 percent discount rate. No risks associated with equipment failure, operation, and maintenance were included; however, benefits associated for FOG tipping and source-separated organics (SSO) tipping were accounted for in the analysis.

2.2.3 Repair and Replacement Costs

Costs associated with repair and replacement of mechanical equipment was assumed to occur once over the 20-year life-cycle analysis. Service life for all mechanical equipment was assumed to be 15 years.

Section 3: SWEET Model Results – Round 1A

For Round 1A of SWEET analysis two separate models were developed, one for biosolids evaluation and one for energy evaluation respectively. The following sections describe the evaluation of each of the models.

3.1 SWEET Round 1A Biosolids Alternatives

End-to-end alternatives were developed using combinations of the above options for thickening, digestion, dewatering, and drying, as deemed relevant. A summary of the solids alternatives considered for Round 1A is provided in Table 3-1.

3.1.1 Solids Stream Comparison Themes

To evaluate alternatives in a more definitive manner, alternatives were selected for comparison such that all but one process remain constant. The major comparison themes were thickening, stabilization (digestion), THP, Class A solids production, and thermal drying.

3.1.1.1 Thickening

The two major thickening technologies evaluated—WAS-only thickening using existing DAFTs, and co-thickening using RDT units—were compared across varying digestion options: specifically, mesophilic, thermophilic with 10-day retention time, and thermophilic with 15-day retention time with two dryers for thermal drying.

3.1.1.2 Stabilization (Digestion)

As one of the major solids stream processes, digestion processes were also compared internally where variables in other processes were held constant. Alternatives where RDT is used for co-thickening, centrifuges for dewatering, with a single dryer, were used to compare the three digestion processes (mesophilic, thermophilic 10-day, and thermophilic 15-day). Thermophilic digestion with 10-day retention time was also evaluated with the use of batch tanks to produce a Class A Cake, amounting to four stabilization options that were compared within this theme. It is important to mention that Thermophilic 10-day digestion process offers more flexibility in terms of digester capacity by allowing the retention time to go down to 10 days; however, in reality, the thermophilic digesters would normally be operated closer to 15 days' retention time.

3.1.1.3 THP

Several alternatives were considered that use THP/digestion configurations. Two THP configurations were evaluated: one that receives all feed streams, and another that receives WAS only. Several THP reactor sizes were also evaluated within each of these streams, with the differing sizes contributing to varying capital cost. The THP alternatives were compared to corresponding alternatives with mesophilic digestion and thermophilic digestion at a 15-day retention time.

3.1.1.4 Class A Cake Production

Alternatives that produce Class A cake were also evaluated for comparison from an end-use perspective. These included all THP alternatives, and thermophilic digestion alternatives with Class A batch tanks.

Table 3-1. Overview of Solids Alternatives Evaluated (Round 1A)										
Alternative No.	Stream Thickened	Thickening Process	SSO Input	Thermal Hydrolysis [a]	Digestion Process	Digestion Enhancements	Dewatering Process	Cake	No. of Dryers	Pellets
1	WAS	DAF	Yes	None	Mesophilic	None	Centrifuge	Class B	1	Yes
2	WAS	DAF	Yes	None	Mesophilic	None	Centrifuge	None	2	Yes
3	WAS + PS	RDT	Yes	None	Mesophilic	None	Centrifuge	Class B	1	Yes
4	WAS + PS	RDT	Yes	None	Mesophilic	None	Centrifuge	None	2	Yes
5	WAS	DAF	Yes	None	Thermophilic, 10-day	None	Centrifuge	None	2	Yes
6	WAS + PS	RDT	Yes	None	Thermophilic, 10-day	None	Centrifuge	Sub Class B	1	Yes
7	WAS + PS	RDT	Yes	None	Thermophilic, 10-day	Class A batch tanks	Centrifuge	Class A	1	Yes
8	WAS + PS	RDT	Yes	None	Thermophilic, 10-day	None	Centrifuge	None	2	Yes
9	WAS	DAF	Yes	None	Thermophilic, 15-day	None	Centrifuge	Class B	1	Yes
10	WAS	DAF	Yes	None	Thermophilic, 15-day	None	Centrifuge	None	2	Yes
11	WAS + PS	RDT	Yes	None	Thermophilic, 15-day	None	Centrifuge	None	2	Yes
12	WAS + PS	RDT	Yes	None	Thermophilic, 15-day	None	Centrifuge	Class B	1	Yes
13	WAS + PS	RDT	Yes	Traditional Cambi, B6-4 reactors (1+1)	Mesophilic	None	Belt filter press	Class A	0	No
14	WAS + PS	RDT	Yes	Traditional Cambi, B6-3 reactors (2+1)	Mesophilic	None	Belt filter press	Class A	0	No
15	WAS + PS	RDT	Yes	Traditional Cambi, B6-4 reactors (1+0)	Mesophilic	None	Belt filter press	Class A	0	No
16	WAS	DAF	Yes	Traditional Cambi, B2-4 reactors (2+1)	Mesophilic	None	Belt filter press	Class A	0	No
17	WAS	RDT	Yes	WAS only Cambi, 2+1 B2-4 reactors (1+0)	Mesophilic	None	Belt filter press	None	2	Yes
18	WAS	RDT	Yes	WAS only Cambi, B6-3 reactors (1+0)	Mesophilic	None	Belt filter press	Class B	1	Yes
19	WAS	DAF	Yes	WAS only Cambi, B2-4 reactors (2+0)	Mesophilic	None	Belt filter press	Class B	1	Yes

a. *Alternatives using THP assume Cambi reactors. Cambi reactor types are shown, with the number of service and standby units.*

3.1.1.5 Thermal Drying

The major options in terms of drying were the continued operation of the single existing thermal dryer, or the operation of two dryers, with the purchase and installation of a new unit. One- and two-dryer alternatives were compared within each digestion option. This included mesophilic digestion, thermophilic at 10-day retention time, thermophilic at 15-day retention time, and WAS-only THP. Conventional THP alternatives were not considered here because they do not assume the need for a dryer.

3.1.2 Economic Evaluation of Solids Stream Alternatives

This section presents the results from the Round 1A SWEET life-cycle analysis for the solids alternatives described previously. The results are presented in the form of bar charts that show the stacking of capital costs and running costs as seen on Figure 3-1. The running costs include all O&M costs, repair and replacement costs, and any associated benefits from FOG and SSO tipping. The stacked bars add up to the NPV over the 20-year planning period for each alternative. The following Table 3-2 shows the breakdown of capital and O&M costs in terms of NPV for all alternatives under evaluation.

Table 3-2. Cost Summary for Solids Alternatives

Number	Description	Capital Cost ($M)	O&M ($M)	Total NPV ($M)
1	DAF-Meso-CD-1D	20.69	107.25	127.94
2	DAF-Meso-CD-2D	45.13	131.97	177.10
3	RDT-Meso-CD-1D	24.38	99.30	123.68
4	RDT-Meso-CD-2D	48.83	124.94	173.77
5	DAF-Thermo10d-CD-2D	43.10	126.11	169.21
6	DAF-Thermo10d-CD-1D	22.35	99.77	122.12
7	RDT-Thermo10d+BT-CD-1D	28.35	102.71	131.07
8	RDT-Thermo10d-CD-2D	46.80	118.90	165.70
9	DAF-Thermo15d-CD-1D	24.33	107.62	131.95
10	DAF-Thermo15d-CD-2D	48.78	132.99	181.77
11	RDT-Thermo15d-CD-2D	52.48	125.89	178.37
12	RDT-Thermo15d-CD-1D	28.03	100.26	128.29
13	RDT-CambiB6-4(1+1)-BFP-0D	88.90	132.17	221.07
14	RDT-CambiB6-3(2+1)-BFP-0D	99.26	139.40	238.66
15	RDT-CambiB6-4(1+0)-BFP-0D	74.77	122.42	197.19
16	DAF-CambiB2-4(4+0)-BFP-0D	75.30	129.52	204.82
17	RDT(WAS)-CambiB6-2-BFP-2D	100.29	153.55	253.84
18	RDT(WAS)-CambiB6-2-BFP-1D	75.84	127.66	203.50
19	DAF(WAS)-CambiB2-4(2+0)-BFP-1D	54.38	130.33	184.71

a. (Duty + standby) unit configuration for THP reactors.

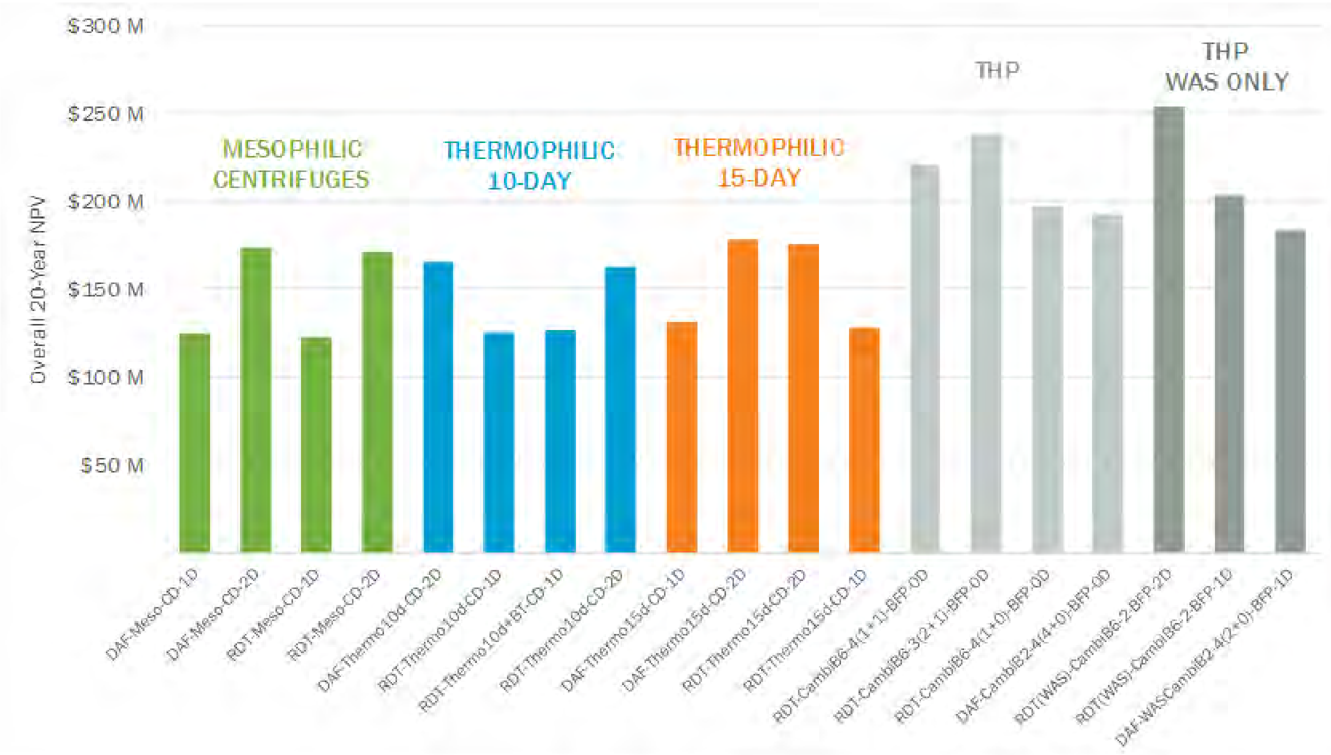

Figure 3-1. Overall 20-year NPV for solids alternatives

3.1.2.1 Thickening Comparison

Figure 3-2 extracts the comparable thickening alternatives from the broader group presented on Figure 3-1 to allow for easier comparison. Overall, the results displayed on Figure 3-2 suggest that the life-cycle costs of RDTs versus rehabilitation of the existing thickening system are comparable. The similarity in overall NPV for the RDT and DAF alternatives is due to the RDT alternative including a higher capital cost but lower operating costs when compared to the DAF alternative.

In addition, the life-cycle costs demonstrate a payback over the planning period with seven RDTs installed. Another option would be to install fewer units for a lower initial capital cost and expand to all seven units in the future, as solids loads to the EWPCF increase. Aiding the final selection of RDTs is the fact that switching thickening technologies opens valuable plant footprint for other processes.

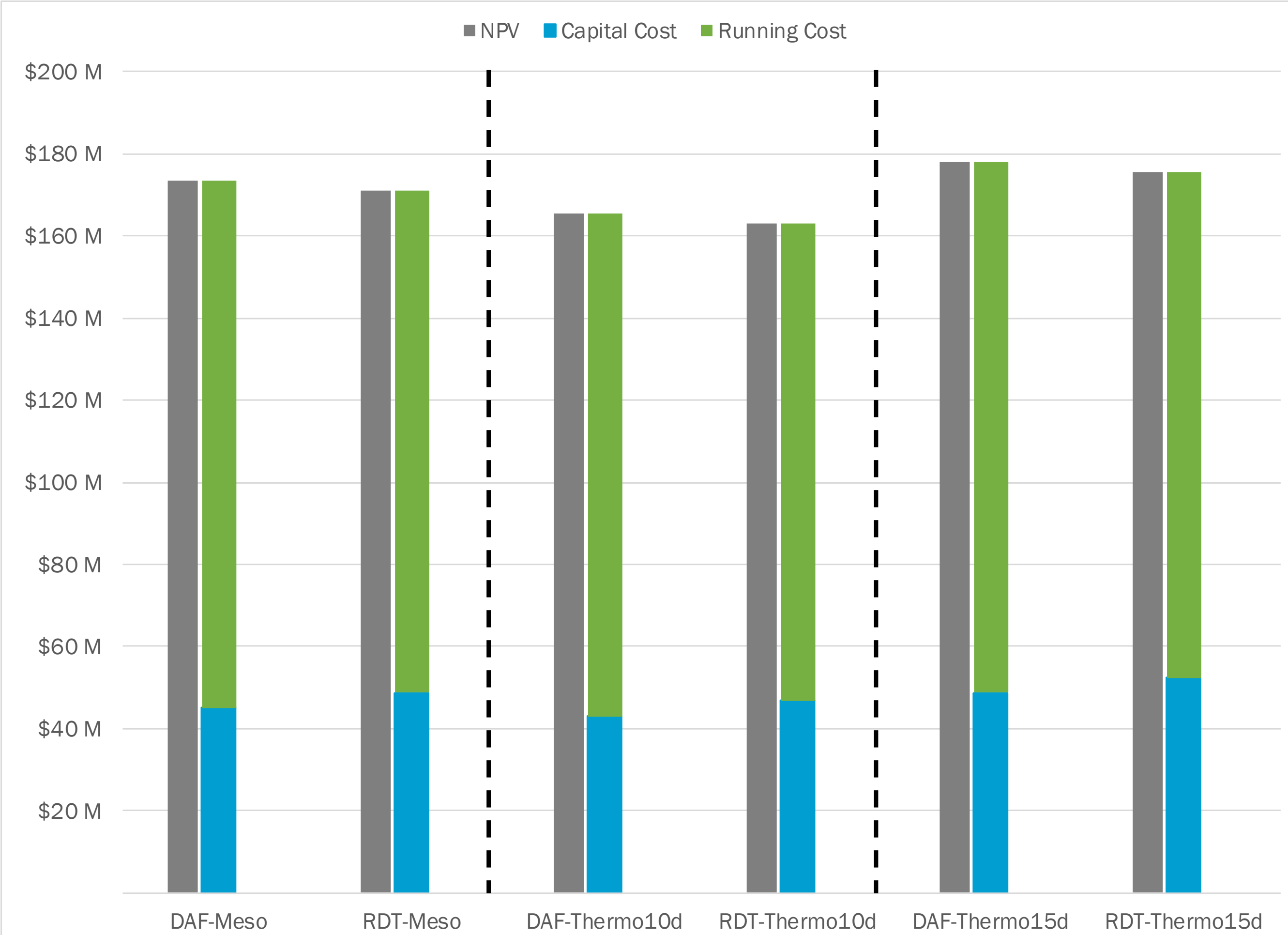

Figure 3-2. Comparison of thickening systems (assuming two dryers)

3.1.2.2 Stabilization Comparison

Figure 3-3 compares the stabilization options side by side. Note that these alternatives have energy implications that could not be fully analyzed until each alternative was combined with one or more energy alternatives. Items of note regarding the stabilization comparison that could be made from this analysis were:

- It is evident that 15-day thermophilic and mesophilic alternatives perform similarly (Figure 3-3).
- Better distinction between thermophilic 10-day and thermophilic 15-day alternatives can be made once these are evaluated together with energy alternatives.

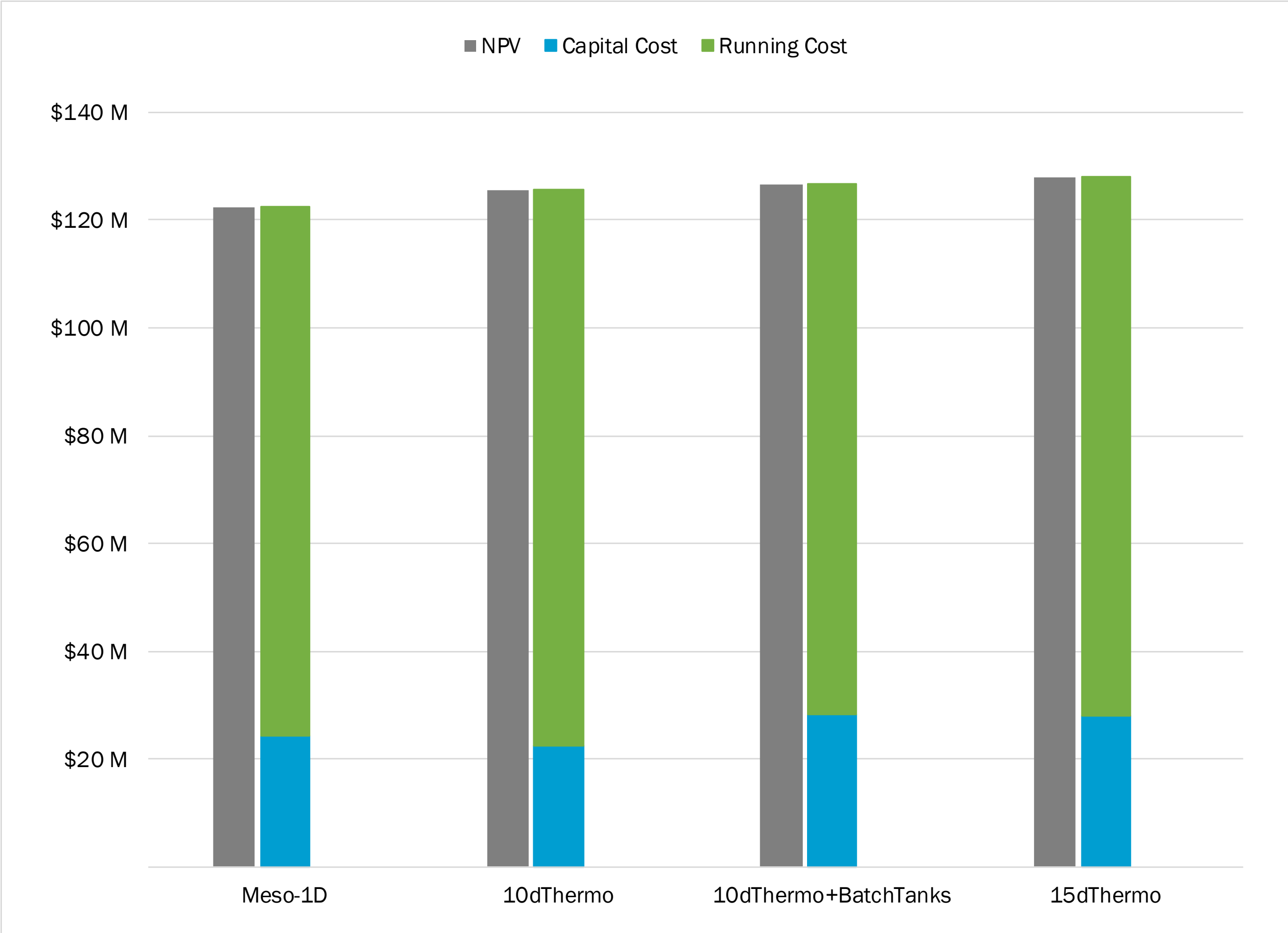

Figure 3-3. Comparison of stabilization options (assuming RDTs and 1 dryer)

3.1.2.3 THP Comparison

The primary purposes of comparing THP alternatives (Figure 3-4) was to identify the best performing configuration for THP at EWPCF. As with the digestion alternatives, a full comparison is not possible without including corresponding energy alternatives. Below are items of note regarding the THP comparison:

- WAS-only THP, designed as a lower capital alternative, does not confer any advantage in terms of eliminating a need for a second dryer or in providing a Class A alternative.
- THP/Digestion alternatives are not combined with thermal drying due to final product concerns.

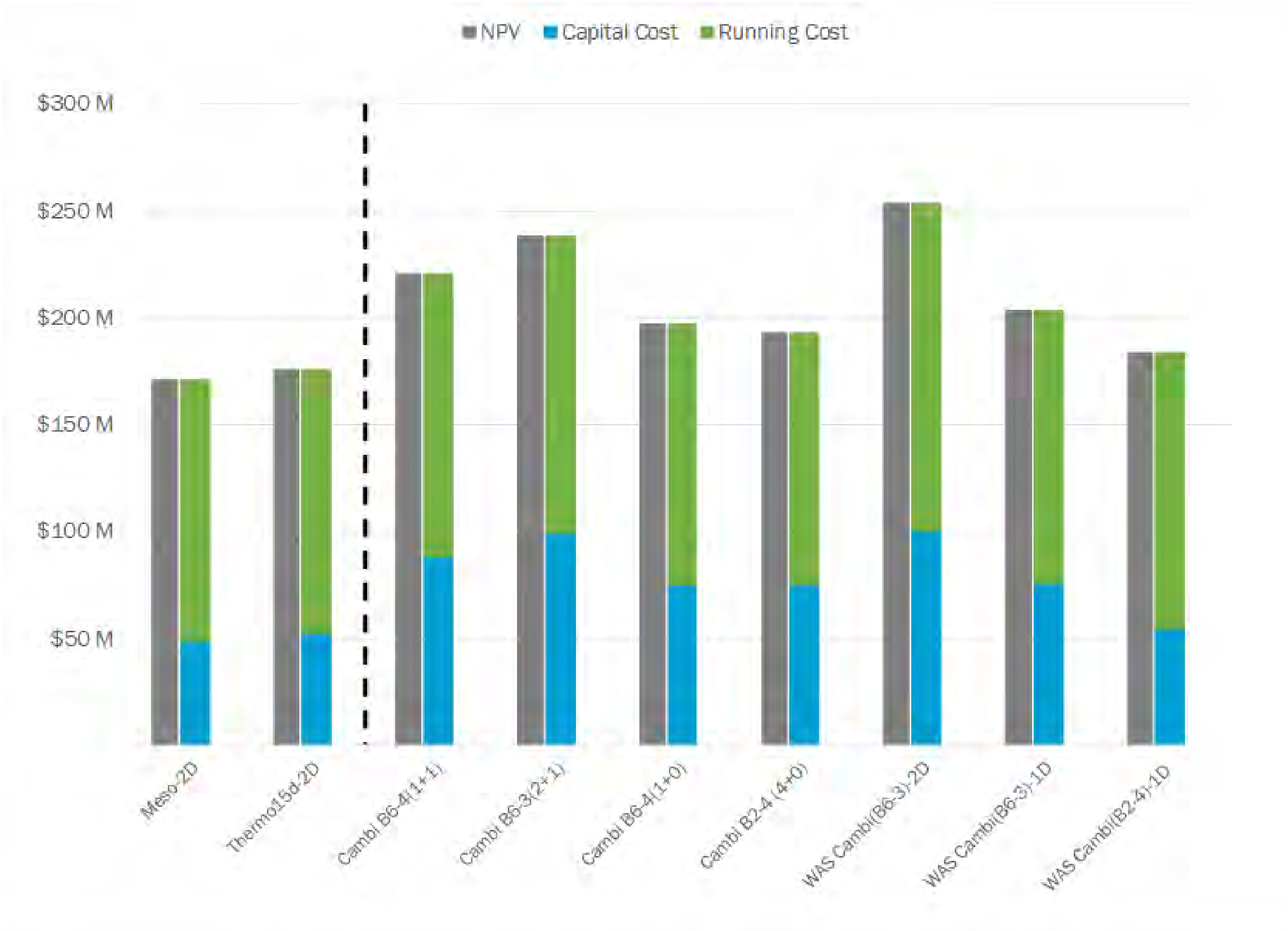

Figure 3-4. Comparison of THP options

3.1.2.4 Class A Comparison

All alternatives that consisted of two dryers, full THP, and 10-day thermophilic with batch tanks were considered to produce Class A out of EWPCF. The results from the evaluation are shown on Figure 3-5 below All Class A alternatives shall be carried forward to the next round of evaluation when combined with energy options to get a clearer picture of how end-use impacts overall life-cycle costs.

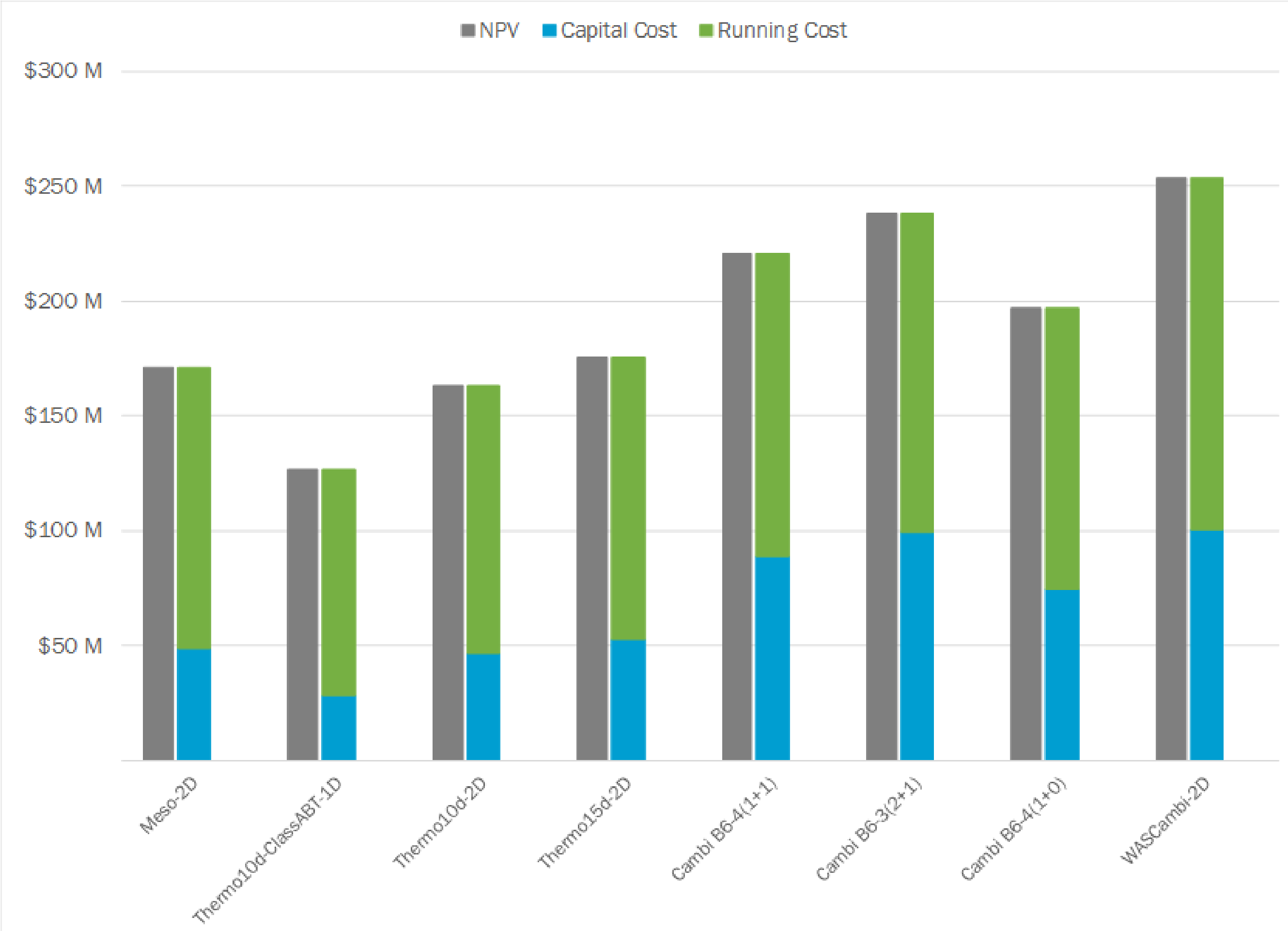

Figure 3-5. Comparison of Class A options (assuming RDTs)

3.1.2.5 Dryer Evaluation

The main purpose of the dryer comparison was to evaluate the overall performance of one dryer versus two dryers (see following Figure 3-6). The results of the evaluation show that the one dryer alternative (two different biosolids products out of EWPCF) is less costly over the life cycle. All dryer alternatives shall be carried forward to the next round of evaluation when combined with energy options. This would provide a clearer picture on energy utilization since different quantities of digester gas would be sent to the dryer based on type of digestion process under evaluation.

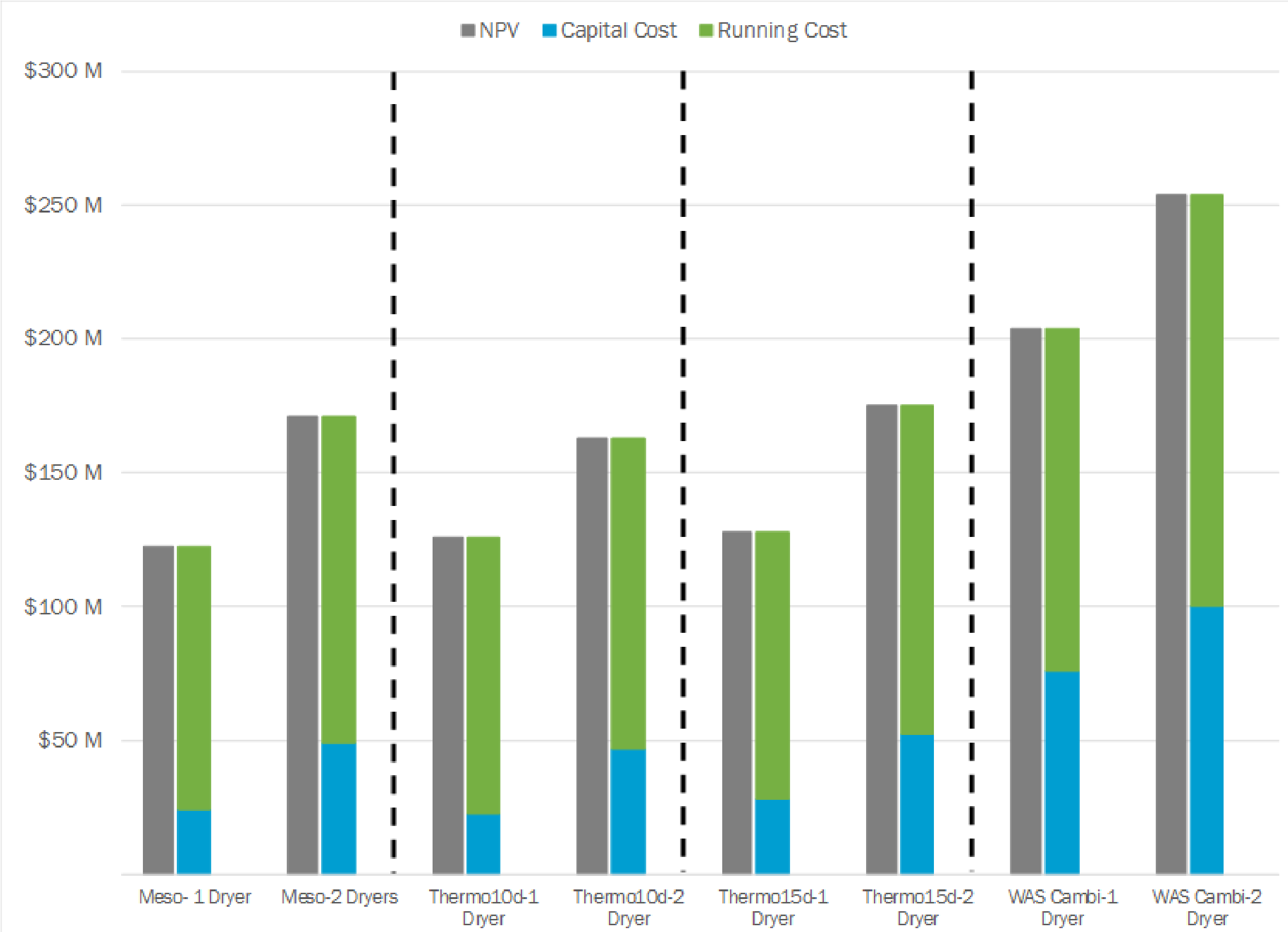

Figure 3-6. Comparison of one dryer versus two dryers

3.1.3 Alternative Selection for Combined SWEET Model (Round 1B)

In merging the solids model with the energy model, most of the solids alternatives were selected to be evaluated in the combined SWEET model. Excluding the baseline, alternatives with existing DAFs were screened out as they show a higher life-cycle cost when compared to RDTs, The DAFs are reaching the end of their useful life which implies a significant capital investment would be required to rehabilitate the system and continue operation. RDTs offer a more competitive life-cycle cost over the 20-year period due to its reduced energy demand and maintenance costs. They also have a much smaller footprint which frees up valuable real estate for EWA in the future.

This section reviews the various energy alternatives developed in the first round of the SWEET model and input assumptions used in the NPV evaluation.

3.2 SWEET Round 1A Energy Alternatives

The initial list of alternatives based on decisions from Workshop 4 and TMs 3, 4, 5, and 6 is presented below. The following main alternatives were considered:

1. Engines (baseline)
2. Engines with gas conditioning
3. Engines with microturbines
4. Pipeline injection
5. Hybrid of engines and pipeline injection
6. Engines with solar (varying sizes and installation locations)
7. NG engines and SCR with all DG to pipeline injection
8. NG engines and SCR with all DG to pipeline injection and solar
9. Large-scale 5-megawatt (MW) cogeneration facility with NEM

Sub-alternatives are indicated with an S, which indicates HSW co-digestion and, therefore, increased DG production. Table 3-3 lists the SWEET Round 1A energy alternatives evaluated.

Table 3-3. Overview of Energy Alternatives Evaluated

Alternative No.	SSO Input	Digestion Process	Gas Conditioning	IC Engine Capacity	Microturbine Capacity	Biogas Upgrading and Pipeline Injection Capacity	Solar	SCR	NEM
1	None	Thermophilic	None	1.92 MW	None	None	None	None	None
1S	Yes	Thermophilic	None	1.92 MW	None	None	None	None	None
2	None	Thermophilic	Yes	1.92 MW	None	None	None	None	None
2S	Yes	Thermophilic	Yes	1.92 MW	None	None	None	None	None
3	None	Thermophilic	Yes	1.92 MW	0.40 MW	None	None	None	None
3S	Yes	Thermophilic	Yes	1.92 MW	0.40 MW	None	None	None	Yes
4	None	Thermophilic	Yes	None	None	800 scfm: 3-year RIN	None	None	None
4S	Yes	Thermophilic	Yes	None	None	1,400 scfm: 3-year RIN	None	None	None
5S	Yes	Thermophilic	Yes	1.92 MW	None	800 scfm: 3-year RIN	None	None	None
6	None	Thermophilic	None	1.92 MW	None	None	Aeration basins (0.40 MW)	None	None
6S	Yes	Thermophilic	None	1.92 MW	None	None	Aeration basins (0.40 MW)	None	Yes
7	None	Thermophilic	None	1.92 MW	None	None	Equalization basins (0.13 MW)	None	None
7S	Yes	Thermophilic	None	1.92 MW	None	None	Equalization basins (0.13 MW)	None	Yes
8	None	Thermophilic	None	1.92 MW	None	None	5-acre field (0.80 MW)	None	None

Table 3-3. Overview of Energy Alternatives Evaluated									
Alternative No.	SSO Input	Digestion Process	Gas Conditioning	IC Engine Capacity	Microturbine Capacity	Biogas Upgrading and Pipeline Injection Capacity	Solar	SCR	NEM
8S	Yes	Thermophilic	None	1.92 MW	None	None	5-acre field (0.80 MW)	None	Yes
9	None	Thermophilic	Yes	2.25 MW (natural gas only)	None	1,400 scfm	None	Yes	None
9S	Yes	Thermophilic	Yes	2.25 MW (natural gas only)	None	1,400 scfm	None	Yes	None
10	None	Thermophilic	Yes	2.25 MW (natural gas only)	None	1,400 scfm	Aeration basins (0.40 MW)	Yes	None
10S	Yes	Thermophilic	Yes	2.25 MW (natural gas only)	None	1,400 scfm	Aeration basins (0.40 MW)	Yes	None
11	None	Mesophilic	None	1.92 MW	None	None	None	None	None
11S	Yes	Mesophilic	None	1.92 MW	None	None	None	None	None
12S	Yes	Thermophilic	Yes	5.00 MW a	None	None	None	None	Yes
14S	Yes	Thermophilic	Yes	1.92 MW	None	1,400 scfm: 10-year RIN	None	None	None

a. Assumes a modified air permit.

A 20-year evaluation was performed to determine the NPV of each alternative based on the assumed capital and O&M costs of Section 2.2. Table 3-4 lists the capital costs, annual O&M costs, and NPVs of each alternative based on the SWEET model inputs and assumptions described in Section 2. Note that the capital costs for additional infrastructure required for HSW receiving are assumed in the solids capital costs. The same methodology in determining costs for the solids model described in Section 2.2 was used for the energy model. Figure 3-7 provides a visual comparison of each alternative aside from Alternative 14S, which is the only one with a negative NPV.

Table 3-4. Economic Summary for Energy 1A Alternatives				
Number	Description	Capital Cost ($M)	NPV of O&M ($M)	Total NPV ($M)
1	Base case: engines + DG to dryer		27.5	27.5
1S	Base case: engines + DG to dryer + HSW	0.5	26.3	26.8
2	Engines + gas conditioning	4.3	24.4	28.7
2S	Engines + gas conditioning + HSW	4.8	23.2	28.0
3	Engines + gas conditioning + microturbines	9.5	25.6	35.1
3S	Engines + gas conditioning + microturbines + HSW	10.0	23.5	33.5
4	Pipeline injection	17.0	28.3	45.3
4S	Pipeline injection + HSW	22.0	8.5	30.6

Table 3-4. Economic Summary for Energy 1A Alternatives				
Number	Description	Capital Cost ($M)	NPV of O&M ($M)	Total NPV ($M)
5S	Engines + pipeline injection + HSW	16.9	(5.0)	11.9
6	Engines + solar on aeration basins	3.0	27.1	30.1
6S	Engines + solar on aeration basins + HSW	1.5	25.8	27.4
7	Engines + solar on equalization basins	2.5	27.4	29.8
7S	Engines + solar on equalization basins + HSW	3.0	26.1	29.0
8	Engines + solar on 5-acre field	3.9	26.4	30.3
8S	Engines + solar on 5-acre field + HSW	4.4	24.8	29.3
9	NG Engines + DG pipeline injection + SCR	20.9	9.6	30.4
9s	NG Engines + DG pipeline injection + HSW + SCR	25.9	(10.5)	15.4
10	NG Engines + DG pipeline injection + SCR + solar on aeration basins	21.4	8.9	30.2
10S	NG Engines + DG pipeline injection + HSW + SCR + solar on aeration basins	26.4	(11.4)	15.0
11	[Mesophilic] + engines	0	28.0	28.0
11S	[Mesophilic] + engines + HSW	0.5	26.5	27.5
12S	Big cogen (5 MW)	31.6	(12.5)	19.1
14S	Pipeline injection: 10-year RIN	22.5	(62.7)	(40.2)

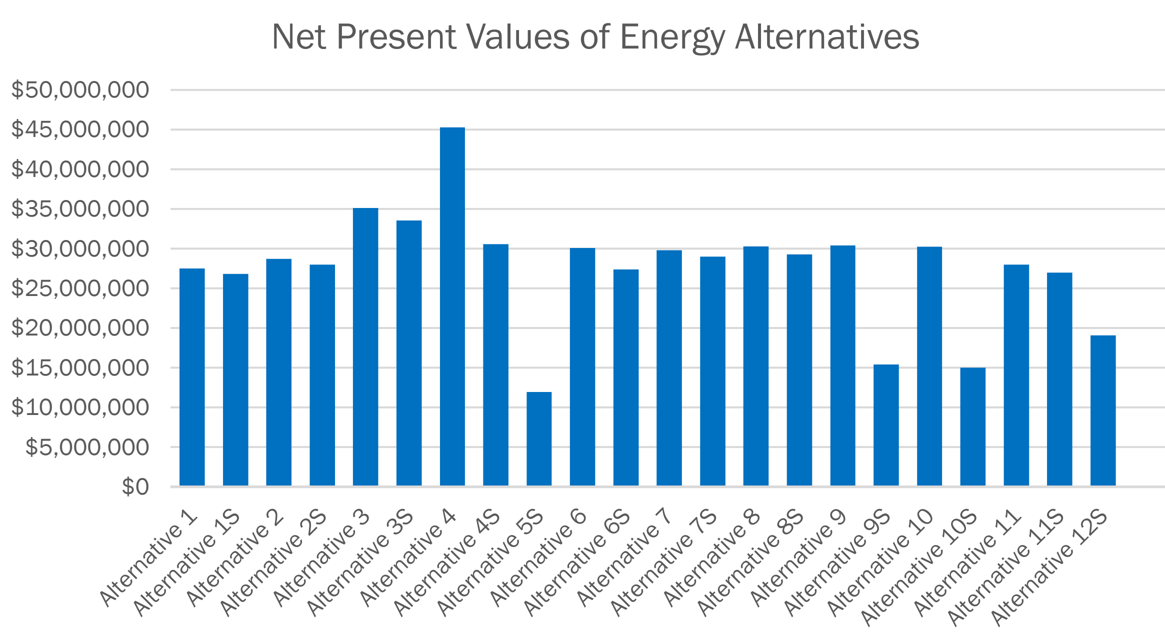

Figure 3-7. Comparison of alternatives

Alternative 14S not included.

Several engine output lines are plotted for combinations of biogas and NG usage. The permitted values of 28 MMscf/year of natural gas and 280 MMscf/year of combined biogas and natural gas are plotted and outline the limits of engine power production.

3.2.1 Engine Alternatives

This section presents an economic evaluation of the engine alternatives.

3.2.1.1 Gas Conditioning

Alternatives 2 and 2S build from Alternatives 1 and 1S, respectively, via the addition of gas conditioning. NPV results indicate that O&M savings from employing gas conditioning over the 20-year period nearly offset the capital cost. Additionally, gas conditioning would also lower O&M costs of the dryer that are not quantified in this analysis. Therefore, it is recommended that EWA install a gas conditioning system in the near future.

3.2.1.2 Solar

Solar alternatives were coupled with the existing IC engines in Alternatives 6 through 8S, ranging from an additional 130 to 800 kW of electrical output. The HSW addition in Alternatives 6S, 7S, and 8S allows for enough electricity production in the early years of the BCE to earn revenue via NEM. However, this revenue stream dissipates as the EWPCF electricity demand climbs past the generation capacity.

Solar power production capacity is cost-effective when digester gas is limited or prioritized for pipeline injection. When enough digester gas is available for the engines to use to meet EWPCF energy demand, solar power is not needed, which makes it not cost-effective under these circumstances. Conversely, when DG use in the engines is limited because of either short supply or diversion to pipeline injection, installing solar power becomes cost-effective by reducing the amount of electricity EWPCF purchases.

Based on the current energy demands at EWPCF and the results of the analysis indicating that solar alternatives do not provide much of a reduction in O&M costs, installation of solar panels is not a priority.

3.2.1.3 Microturbines

Despite providing excess power generation and electricity revenue in the early years of the BCE, the microturbine alternatives did not result in enough savings or revenue to offset capital costs, leaving them with NPVs higher than the baseline models. Microturbines are not recommended for installation at EWPCF.

3.2.1.4 Large-Scale Cogeneration

Alternative 12S explored the effect of large-scale cogeneration by assuming a revised air permit, which would allow for a total IC engine capacity of 5 MW. The increased capacity allows EWA to export power to its member agencies via NEM sale. This revenue stream makes Alternative 12S one of the more attractive scenarios tested, with an NPV lower than the baseline scenarios. The success of this alternative is due to the efficient utilization of excess biogas and is feasible only when co-digestion is maximized, and therefore is not a priority alternative.

3.2.2 Pipeline Injection Alternatives

This section presents an economic evaluation of the pipeline injection alternatives.

3.2.2.1 100 Percent Pipeline

Alternatives 4 and 4S demonstrate that using 100 percent of EWPCF biogas for pipeline injection does not generate enough revenue to pay back the capital costs and these options raise electricity costs over the 30-year BCE. However, the addition of HSW co-digestion and installation of a higher-capacity BUS allowed

Alternative 4S to collect significantly more revenue and reduce its NPV. This led to the exploration of a hybrid alternative that incorporated engines and pipeline injection, detailed in the following section.

3.2.2.2 Engines with Pipeline Injection

Alternative 5S is a hybrid engine and pipeline injection option that assumes maximizing IC engine output and pipeline injection of excess biogas, which yielded the lowest NPV aside from Alternative 14S. The success of this alternative is similar to that of Alternative 12S, the large-scale cogeneration alternative. Here, the capital improvements of a biogas upgrading and pipeline injection system pay off when co-digestion of HSW is incorporated. Like Alternative 12S, Alternative 5S creates a strong revenue stream using excess biogas from HSW co-digestion to attain environmental attributes and avoid peak and demand electrical charges. This alternative provides operational flexibility to handle peaks in biogas production by sending it to the pipeline while also meeting the EWA goal of power production. A hybrid engine and pipeline injection alternative is recommended for near-term implementation.

3.2.2.3 Pipeline Injection with NG Engines

Alternatives 9 through 10S all combine 100 percent biogas utilization for pipeline injection with SCR-mediated cogeneration using only natural gas. Like Alternative 5S, this scenario allows for maximum IC engine output paired with revenue-generating pipeline injection. The main difference is that Alternatives 9 through 10S prioritize biogas for pipeline injection and use natural gas strictly for IC engine operation. Additionally, SCR allows the engines to produce beyond the permit limit and up to the EWPCF capacity (2.25 MW). While the overall alternative NPV is lower than that of the baseline scenarios, the high capital cost of SCR leaves this alternative with a higher NPV than Alternative 5S. Because these alternatives do not provide significant value and are higher risk than the hybrid engine and pipeline injection project, they are not recommended for implementation.

3.2.2.4 Effect of RINs

The current RFS (RFS2) for RINs does not end in 2022; however, the dictated escalation of required renewable volumes of fuel does stop on December 31, 2022. The rule requires that volume obligations of renewable fuel for years after 2022 be at least equal to, or larger than, the current volume. Because there is uncertainty with the value of future RINs after 2022, the alternatives incorporating pipeline injection assume that the program ends on that day. These alternatives have the potential to generate significantly more revenue while the RFS2 is in place.

Alternatives 13S and 14S were developed to examine how an increase in RIN lifetime affected NPV, assuming IC engines would utilize biogas once incentives ran out. An increase from 3 to 10 years in RIN lifetime between the two resulted in more than $70 million of additional revenue. Unlike NEM of excess electricity, the sale of biogas through pipeline injection offers two revenue streams: the actual sale of upgraded biogas and the value of RINs. It is likely that RINs will continue to exist for more than 3 years, meaning that a continued financial payback like Alternative 14S can be a likely situation.

3.2.3 High-Strength Waste Addition

A major theme and general conclusion of the SWEET model is that the co-digestion of HSW universally lowered NPV. An assumed capital cost of $500,000 for HSW receiving infrastructure is quickly paid back because of the revenue generation linked to the additional biogas production. Gas production that exceeds plant demand yields valuable returns with pipeline injection and also reduces purchase of supplemental natural gas. Alternatives 5S, 9S, 10S, and 12S all had lower NPVs than the baseline alternatives because the addition of HSW co-digestion allowed for higher production and utilization of biogas via extra engine capacity or pipeline injection or both.

It should also be noted that not a single alternative without HSW co-digestion resulted in a lower NPV than the baseline alternatives. This shows the resilience of the baseline scenario with a modified air permit as well as the significance of HSW co-digestion in lowering NPV. It is recommended that EWA pursue additional HSW contracts and increasing the size of the existing HSW facility to accommodate a larger co-digestion program.

3.2.4 Alternative Selection for Combined SWEET Model (Round 1B)

In merging the energy model with the solids model, the energy alternatives were narrowed to the baseline cogeneration alternative (status quo) and a hybrid engines and pipeline injection alternative. These two alternatives will be merged with the selected solids alternatives in a combined SWEET model. Both alternatives offered competitive NPVs and potential revenue without significant risks. The results of the initial SWEET analysis indicate that gas conditioning offers O&M benefits and is nearly break-even with the baseline alternative; for this reason, it is not carried forward into the combined SWEET analysis as a separate alternative, but may be considered as having nearly the same NPV as the baseline alternative.

Section 4: Combined Solids and Energy SWEET Model Results - Round 1B

Analysis of the solids model and the energy model individually provides a distinct picture of how the alternatives perform on their own over the life-cycle. The results from the previous round also provides information to screen out some of the apparent outliers in the solids and energy alternatives in terms of life-cycle costs. On combining the solids and the energy models, a more comprehensive analysis can be made with how the solids processes impact the energy utilization within the plant. The benefits derived from reduced energy requirement affect the overall life-cycle costs.

The combined SWEET model involved merging the solids model and the energy model into one. The combined model then generates the overall life-cycle costs for the end-to-end alternatives. The two primary energy alternatives selected were baseline cogeneration alternative and a hybrid engine and pipeline injection alternative. These two energy alternatives were evaluated with each individual biosolids alternative listed in the following Table 4-1.

4.1 Round 1B Alternatives

On analysis of results from Round 1A, a new set of alternatives were developed that combined the solids and energy alternatives into one SWEET model. These end-to-end alternatives were developed using combinations of the above options for thickening, digestion, dewatering, and drying, as deemed relevant.

Table 4-1. Overview of Alternatives Evaluated (Round 1B)[a]										
Alternative No.	Stream Thickened	Thickening Process	SSO Input	Thermal Hydrolysis [b]	Digestion Process	Digestion Enhancements	Dewatering Process	Cake	No. of Dryers	Pellets
1	WAS	DAF	Yes	None	Mesophilic	None	Centrifuges	Class B	1	Yes
2	WAS + PS	RDT	Yes	None	Mesophilic	None	Centrifuges	Class B	1	Yes
3	WAS + PS	RDT	Yes	None	Mesophilic	None	Centrifuges	None	2	Yes
4	WAS + PS	RDT	Yes	None	Mesophilic	Recuperative thickening	Centrifuges	Class B	1	Yes
5	WAS + PS	RDT	Yes	None	Mesophilic	Recuperative thickening	Centrifuges	None	2	Yes
6	WAS + PS	RDT	Yes	None	Thermophilic, 10-day	None	Centrifuges	Sub Class B	1	Yes
7	WAS + PS	RDT	Yes	None	Thermophilic, 10-day	Class A batch tanks	Centrifuges	Class A	1	Yes
8	WAS + PS	RDT	Yes	None	Thermophilic, 10-day	None	Centrifuges	None	2	Yes
9	WAS + PS	RDT	Yes	None	Thermophilic, 15-day	None	Centrifuges	None	2	Yes
10	WAS + PS	RDT	Yes	None	Thermophilic, 15-day	None	Centrifuges	Class B	1	Yes
11	WAS + PS	RDT	Yes	None	Thermophilic, 15-day	Class A batch tanks	Centrifuges	Class A	1	Yes
12	WAS + PS	RDT	Yes	Traditional Cambi, B6-4 reactors (1+1)	Mesophilic	None	Belt filter press	Class A	0	No
13	WAS + PS	RDT	Yes	Traditional Cambi, B6-3 reactors (2+1)	Mesophilic	None	Belt filter press	Class A	0	No
14	WAS	DAF	Yes	Traditional Cambi, B6-4 reactors (1+0)	Mesophilic	None	Belt filter press	Class A	0	No
15	WAS + PS	DAF	Yes	Traditional Cambi, B2-4 reactors (2+1)	Mesophilic	None	Belt filter press	Class A	0	No
16	WAS + PS	RDT	Yes	Traditional Cambi B4-4 reactors (2+1)	Mesophilic	None	Belt filter press	Class A	1	Yes
17	WAS + PS	RDT	Yes	Traditional Cambi, B4-4 reactors (2+0)	Mesophilic	None	Belt filter press	Class A	0	No
18	WAS	RDT	Yes	WAS only Cambi, B6-3 reactors (1+0)	Mesophilic	None	Belt filter press	None	2	Yes
19	WAS	RDT	Yes	WAS only Cambi, B2-4 reactors (1+0)	Mesophilic	None	Belt filter press	Class B	1	Yes
20	WAS	DAF	Yes	WAS only Cambi, B2-4 reactors (2+0)	Mesophilic	None	Belt filter press	Class B	1	Yes
21	WAS + PS	RDT	Yes	None	Mesophilic	None	Screw press	None	2	Yes
22	WAS	DAF	Yes	None	Mesophilic	None	Screw press	None	2	Yes
23	WAS + PS	RDT	Yes	None	Mesophilic	None	Belt filter press	None	2	Yes
24	WAS	DAF	Yes	None	Mesophilic	None	Belt filter press	None	2	Yes

a. Each alternative listed was evaluated with the two primary energy alternatives (Engines only and Engines+Pipeline Injection).

b. Alternatives using THP assume Cambi reactors. Cambi reactor types are shown, with the number of service and standby units.

The following are key items that were included in developing this round of alternatives:

- The two primary energy alternatives include engines only up to existing air permit and engines with pipeline injection.
- Alternatives that evaluated existing DAFs for thickening were screened out except for the one that represents the baseline.
- Additional Cambi reactor sizes were evaluated for THP/digestion alternatives.
- Omnivore technology (Recuperative thickening) was introduced as an option to provide more digester capacity and evaluated with mesophilic digestion. In this scenario, the existing small Digesters 1 and 2 would be repurposed to be used as Omnivore tanks with additional thickening equipment and a new mixing system within the tanks.
- Thermophilic digestion at 10-day and 15-day were evaluated with batch tanks to provide Class A Cake.
- Different dewatering technologies such as Belt Filter Press and Screw Press were added to alternatives with two dryers for evaluation.
- One and two dryer alternatives were evaluated due to the non-cost advantages provided by the second dryer.

Each alternative shown in the table is compared with two energy options, one with engines and one with a hybrid of engines and pipeline injection.

4.2 Economic Evaluation of Solids and Energy Alternatives

Results from Round 1B of the SWEET life-cycle analysis for all alternatives under consideration are presented on Figure 4-1 below.

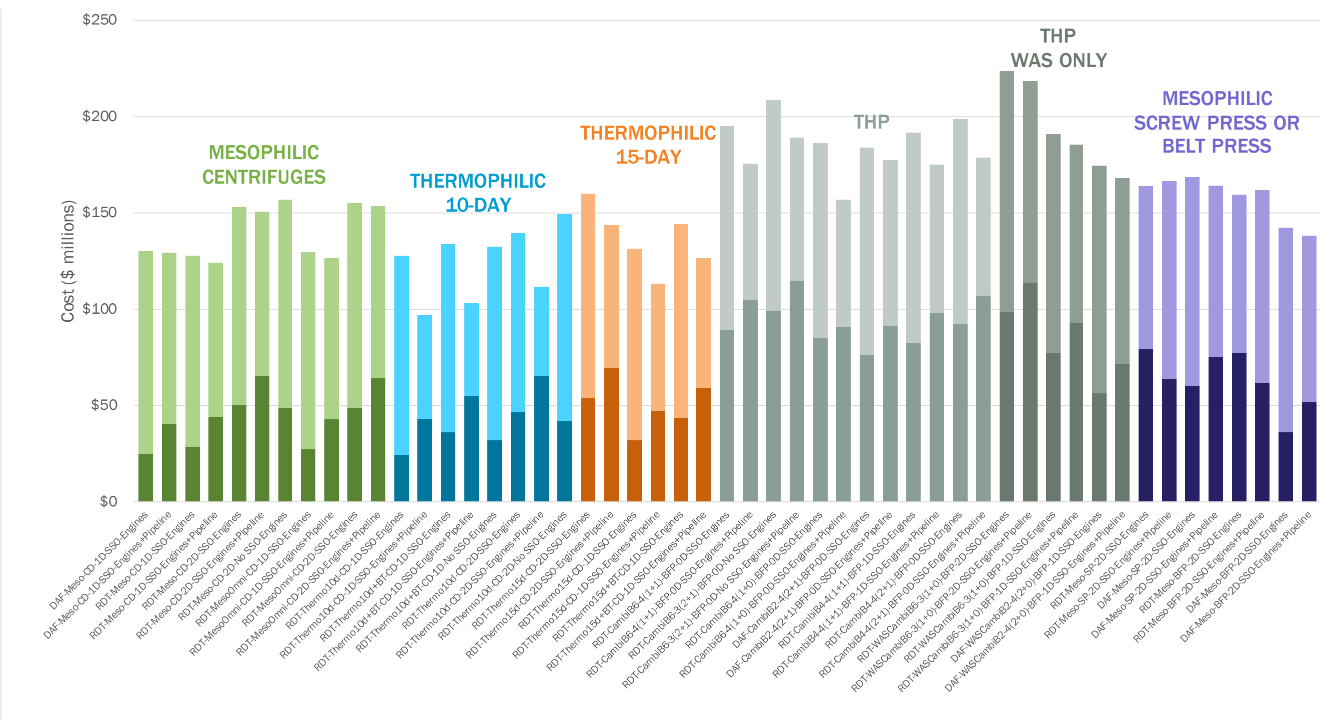

Figure 4-1. Overall NPV for all alternatives

From the figure above, it is evident that all the THP options represent a much higher NPV over 20 years compared to the other alternatives. These options were screened out from further consideration, particularly since they do not offer sufficient non-cost advantages to justify the higher cost.

Figure 4-2 provides a closer look at the results without THP.

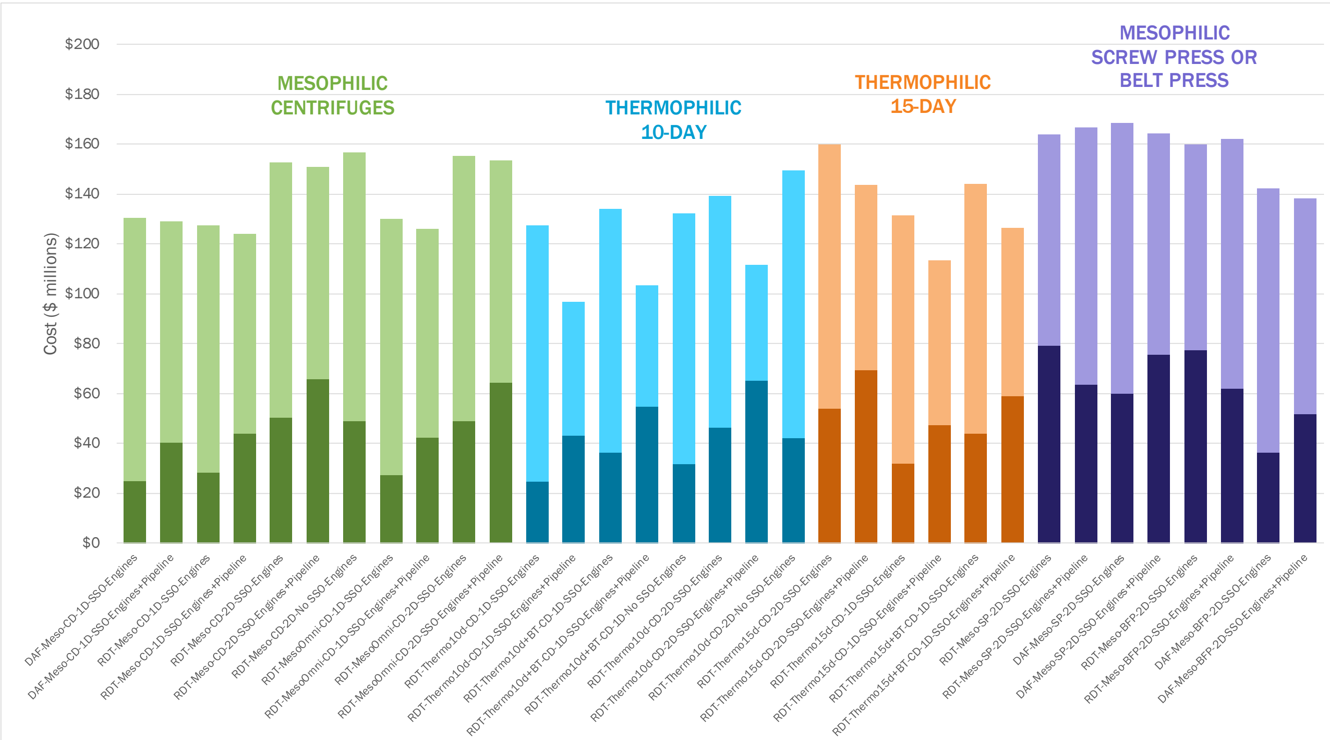

Figure 4-2. Overall NPV for all alternatives without THP

4.2.1 Dryer Evaluation

The following Figure 4-3 compares alternatives with one dryer and two dryers for different digestion scenarios such as mesophilic, thermophilic 10-day, and thermophilic 15-day. Overall, alternatives with two dryers have a higher NPV compared to those with one dryer because of the higher capital cost. The operating and running costs over time for the one- and two-dryer options are comparable. EWA staff felt there were important non-cost advantages to a second dryer, so the decision was made to preserve some two dryer alternatives for the best performing digestion alternatives.

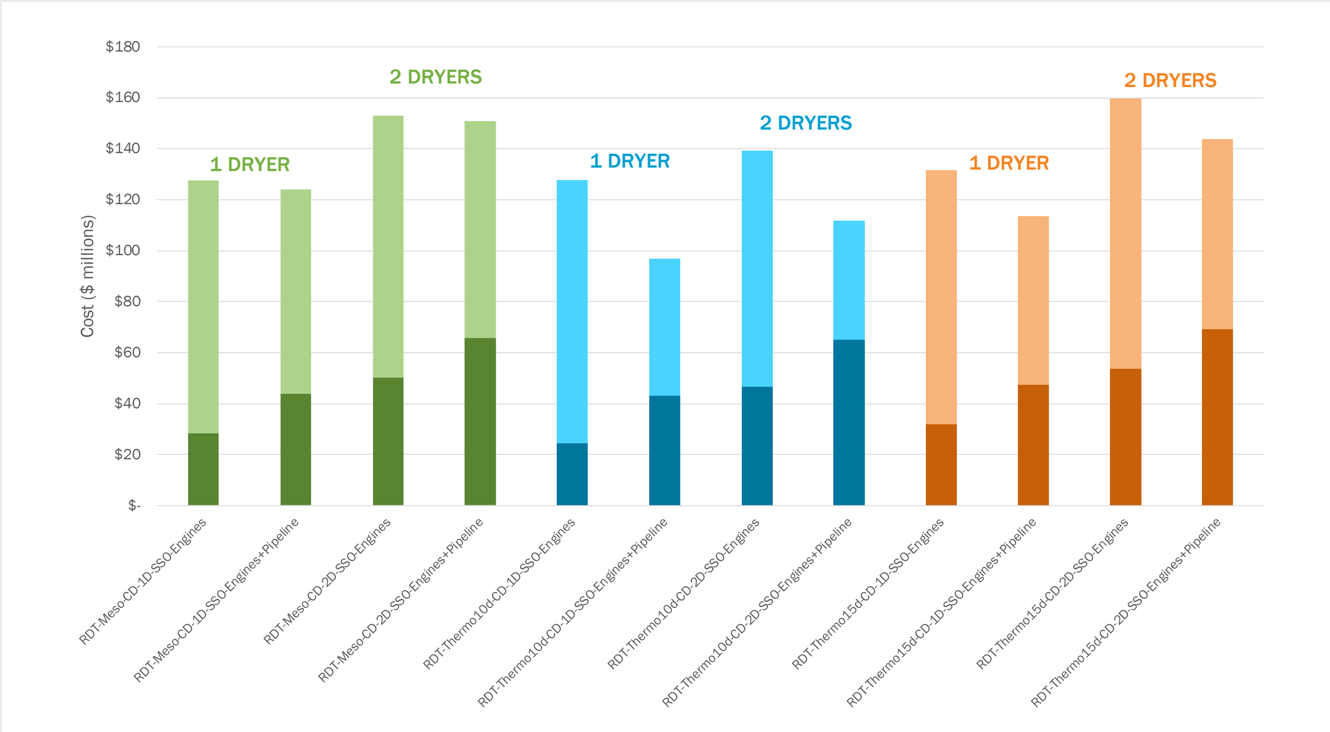

Figure 4-3. One dryer versus two dryers

4.2.2 Final Product Evaluation

The following Figure 4-4 compares alternatives that produce only one type of finished product (Class A pellets) versus producing two types of biosolids products (Class A pellets and Class B cake). The results from this evaluation suggest that the costs to produce only pellets (with two dryers) as the finished product out of EWA is higher than producing a portion of pellets and hauling the remaining Class B cake. The latter has a lower capital cost compared to any option with two dryers, as implied by the previous figure.

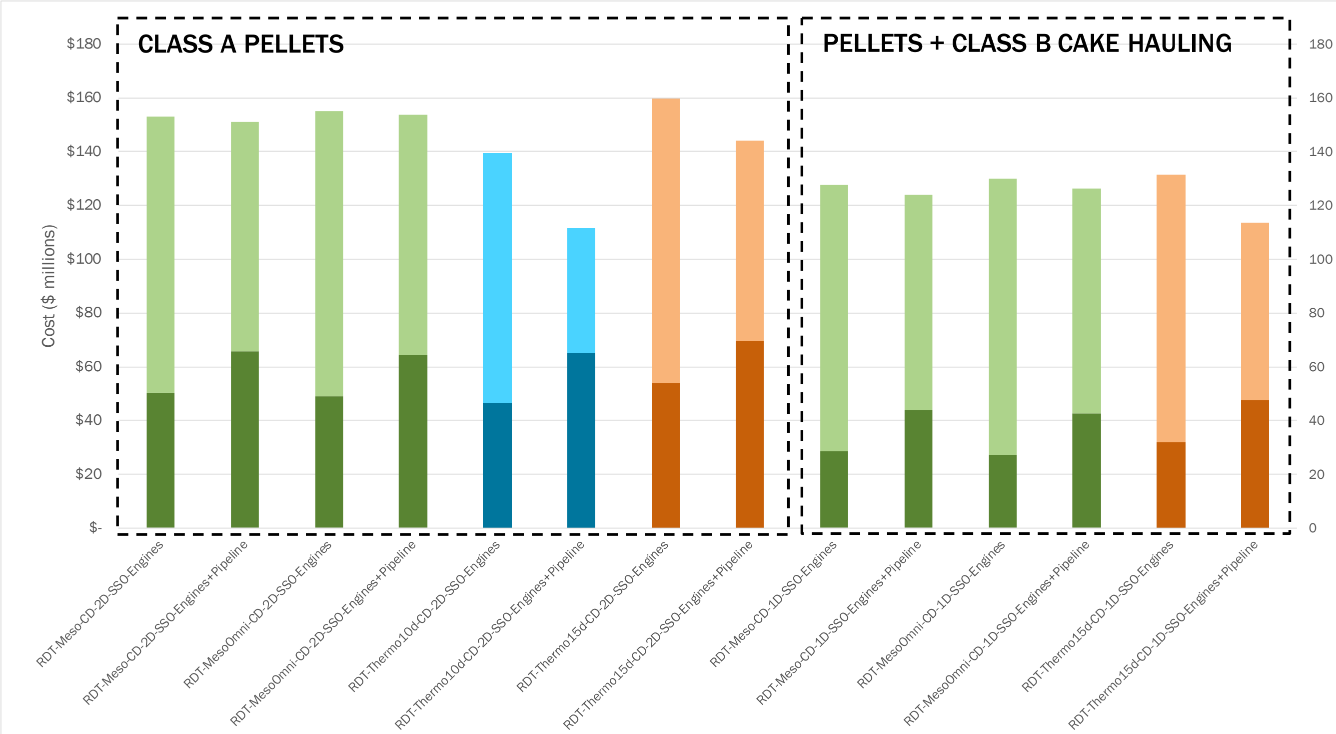

Figure 4-4. Class A pellets versus pellets and Class B cake hauling

4.2.3 Source-Separated-Organics Evaluation

The following Figure 4-5 compares options that were evaluated with and without importing SSO. SSO importing was considered additional over the already existing FOG and brewery waste quantities. The results suggest that the life-cycle costs for no SSO are higher than those that do import SSO. This is attributed to the benefits associated with SSO tipping fees and more effective energy utilization in the options that import SSO, and is consistent with the findings of the Round 1A energy evaluation.

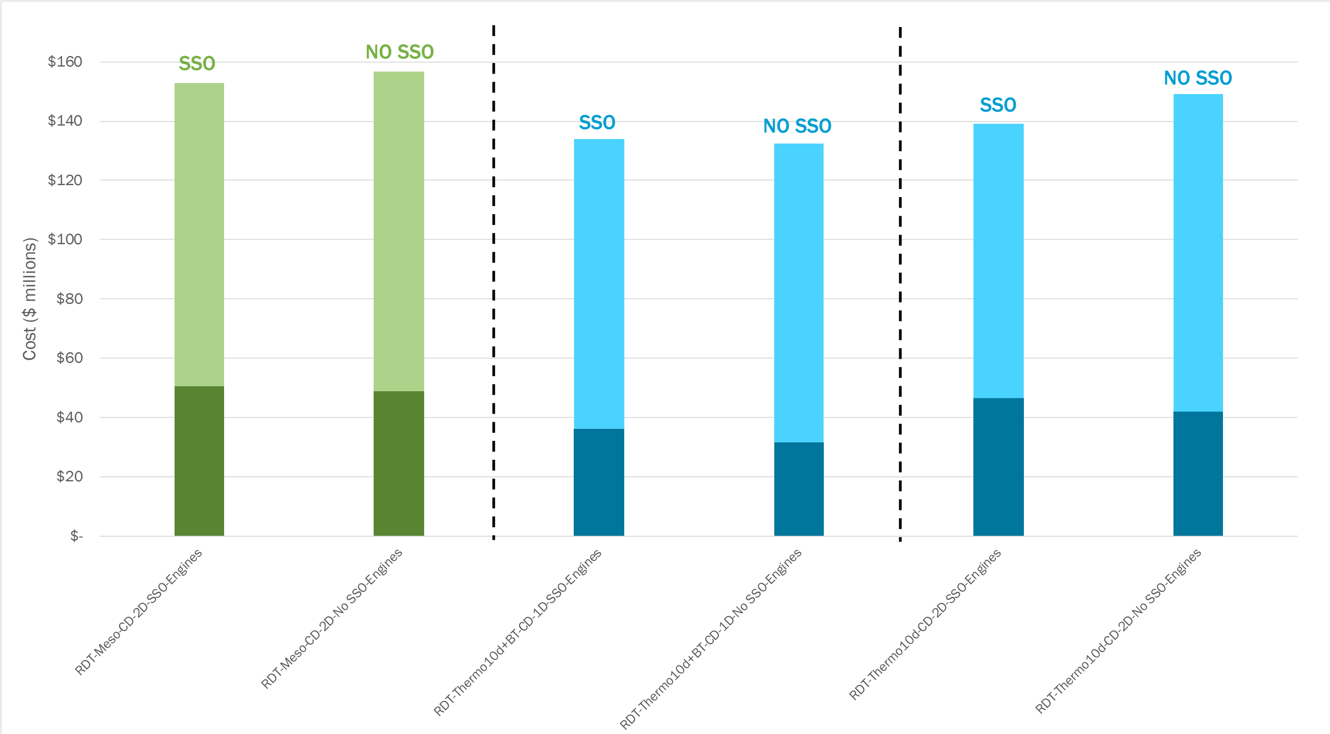

Figure 4-5. SSO versus no SSO

4.2.4 Thickening Evaluation

The following Figure 4-6 shows the results of evaluating existing DAFTs with mesophilic digestion versus RDTs with mesophilic digestion. The RDTs have a lower running cost, especially in terms of energy, but a higher initial capital investment. However, over the life cycle the NPV of RDTs is lower than that of DAFs. As mentioned previously, RDTs also provide an important advantage of freeing up valuable footprint on the EWA site.

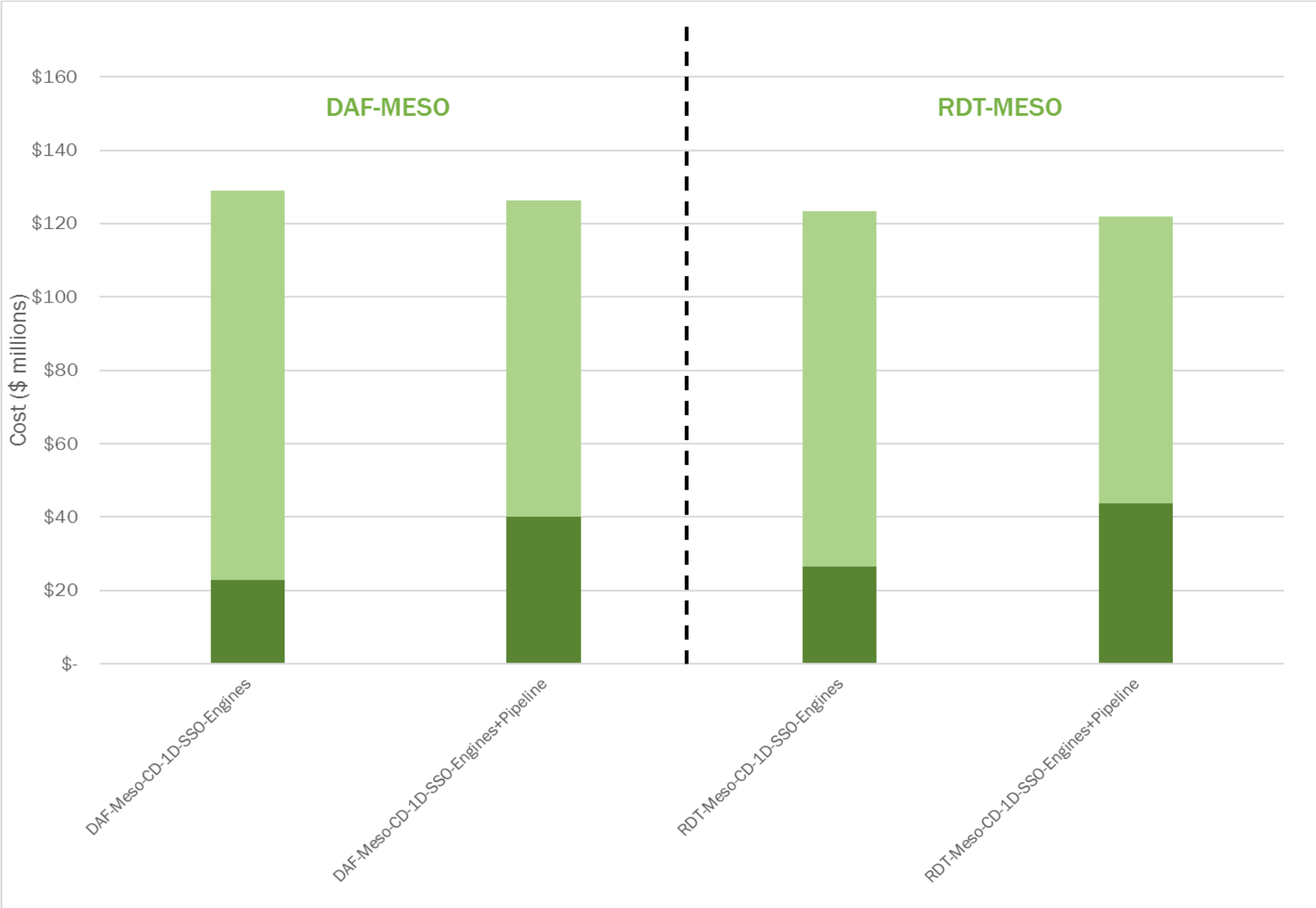

Figure 4-6. DAF versus RDT

4.2.5 Energy Evaluation

Because the revised engine permit allows for a maximum DG usage of 533 scfm, on average, any DG in excess of the permit limit can either be utilized in the dryer or sent to the pipeline. Or, with a revised air permit, gas conditioning, NEM, and a CO catalyst, additional gas can be utilized in the engines. Figure 4-7 shows the DG production as a function of HSW co-digestion assuming mesophilic digestion in addition to key operating points assuming a current baseline DG production of 500 scfm without any HSW addition.

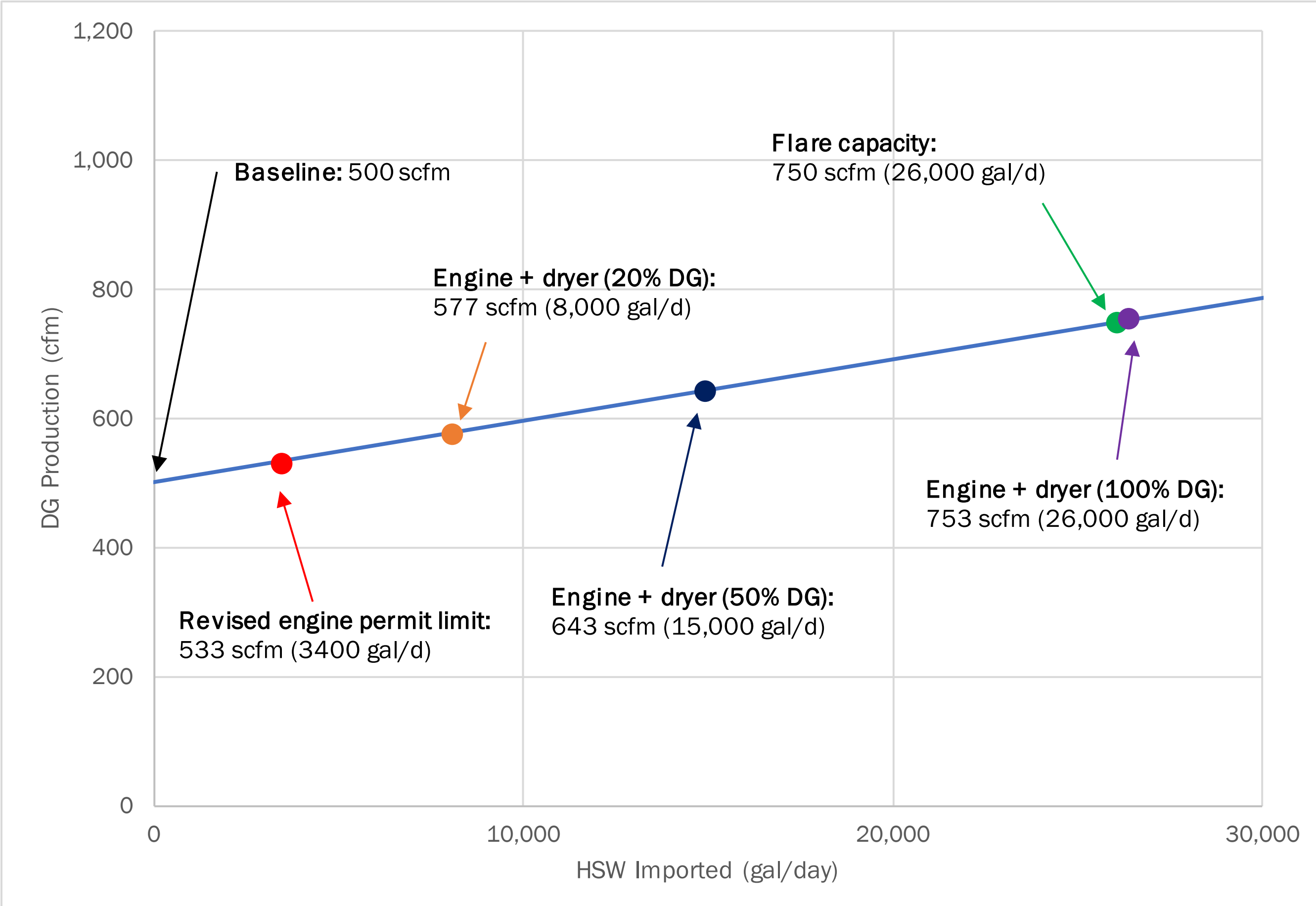

Figure 4-7. DG production as a function of HSW co-digestion with key operating points

The results of the energy SWEET model were refined for a solids treatment process including RDTs, mesophilic digestion and one dryer based on the feedback from Workshop 4. While the engines only and engines with pipeline injection energy alternatives were carried forward into the Round 1B model, several alternatives were continued to be modeled in conjunction with the preferred solids treatment process. Figures 4-8 to 4-10 show the energy SWEET model results assuming the preferred solids process with varying levels of RINs durations and values. These figures assume 15,000 gallons per day of HSW for co-digestion, or approximately 690 scfm of "day 1" DG production.

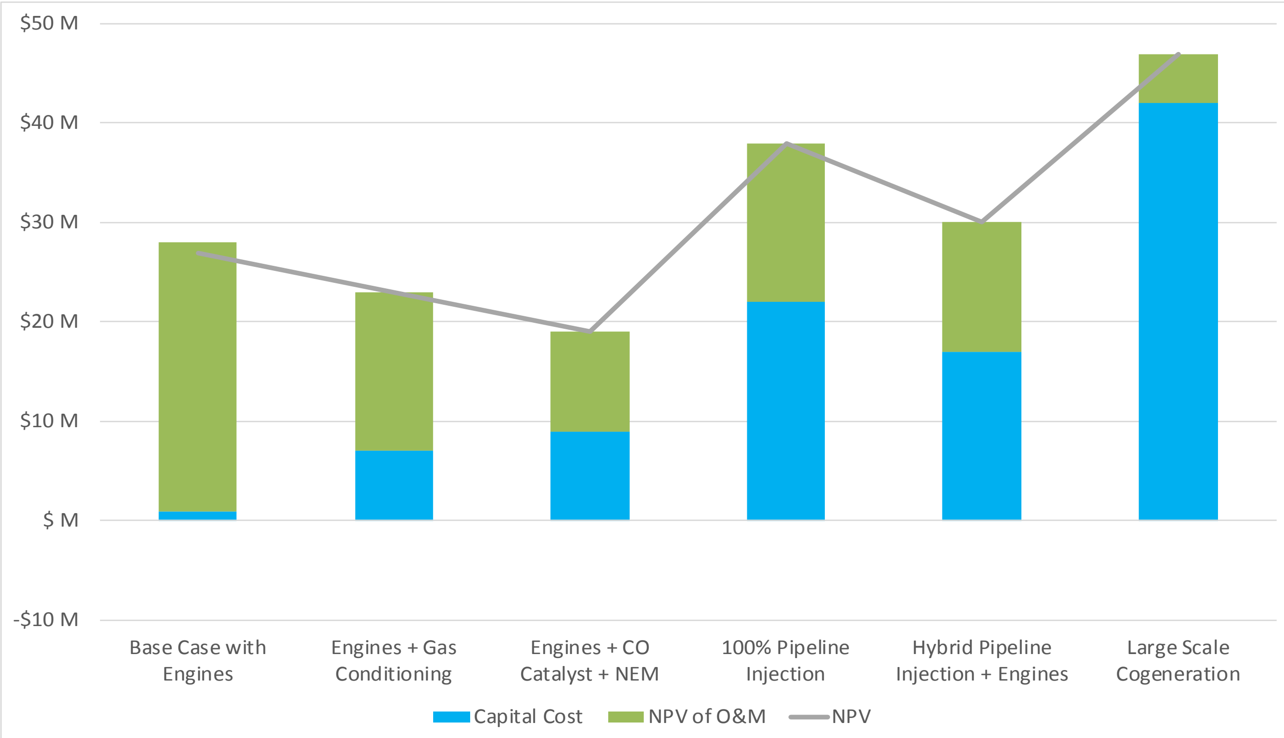

Figure 4-8. BCE results with HSW and RINs until 2022 (full value) with standby charges removed for all alternatives except base case

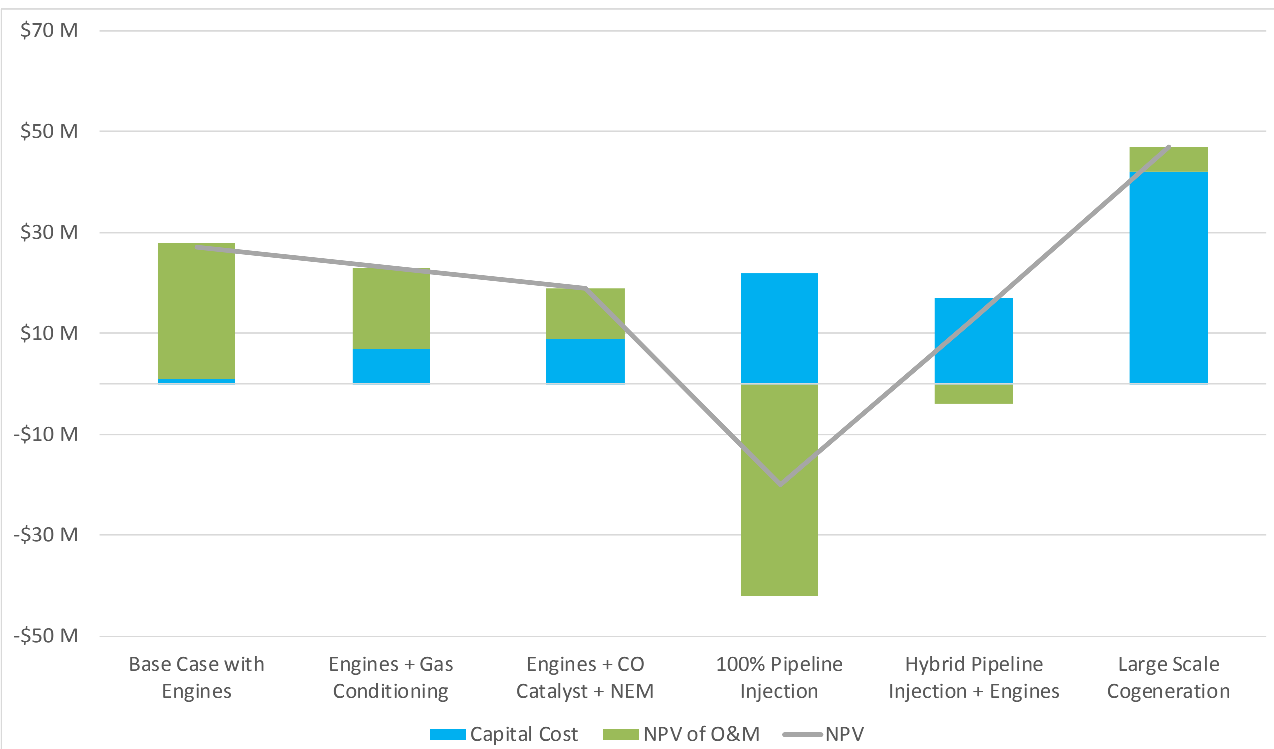

Figure 4-9. BCE results with HSW and RINs to 2030 (full value) with standby charges removed for all alternatives except base case

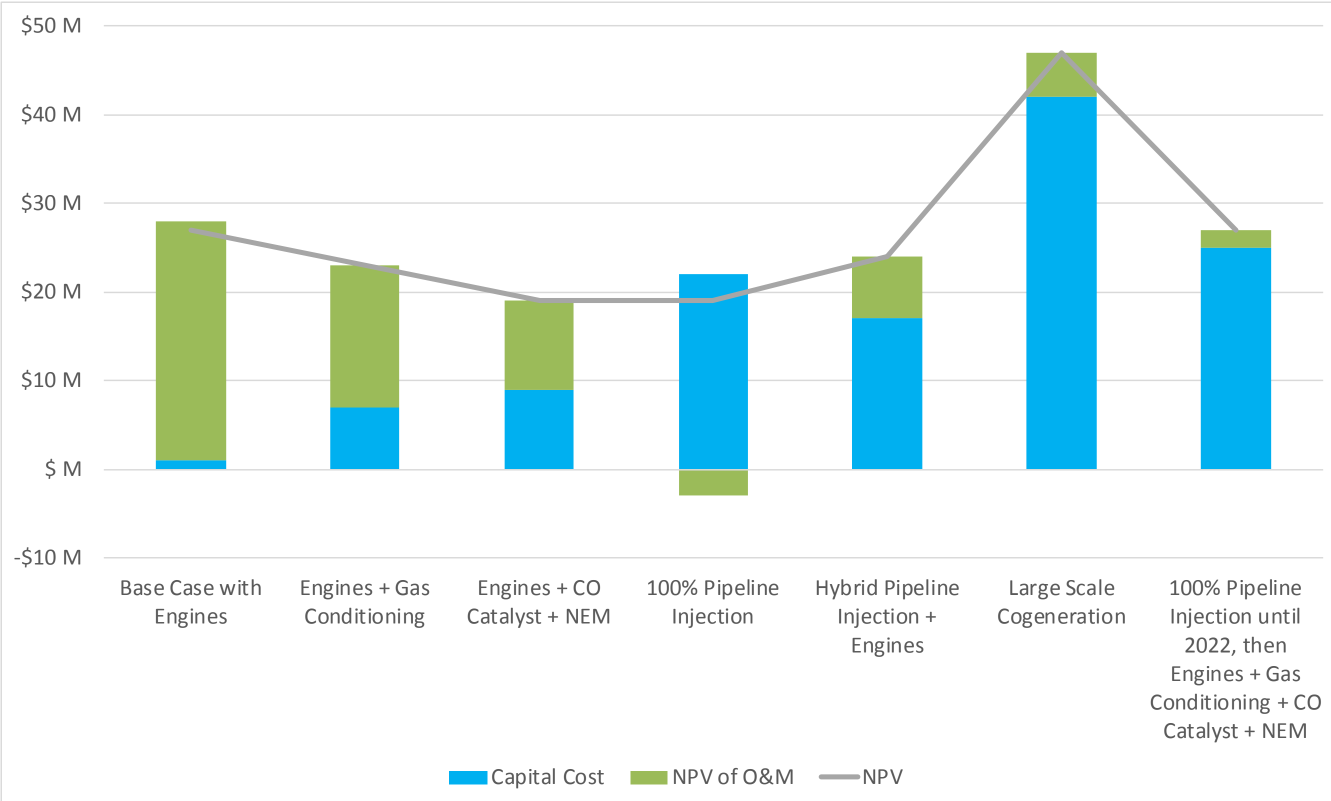

Figure 4-10. BCE results with HSW and RINs to 2030 (half value) with standby charges removed for all alternatives except base case

Based on the findings of the SWEET model, the alternatives EWA should pursue and consider for capital improvement include the following:

- Run engines up to the permit limit and send the remainder of the gas to the pipeline. Pursue an NEM schedule with San Diego Gas & Electric (SDG&E) to avoid standby charges (hybrid engines + pipeline injection).
- Provide gas conditioning upstream of engines followed by a CO catalyst on engine exhaust to unlock more engine capacity via air permit modification. Pursue an NEM schedule with SDG&E to avoid standby charges (engines + gas conditioning + CO catalyst).

When coupled with the solids alternatives, The SWEET model results indicate the following findings:

- Digester gas is more financially valuable when injected into the pipeline based on current NG prices, LCFS credit prices, and RINs credit prices that provide revenue to EWA. Revenue from LCFS and RINs credits, based on current market value, can provide significant financial value to EWA.
- Regardless of technology, the addition of HSW for co-digestion improves the overall economics, leading to a recommendation that EWA increase the size of its HSW receiving facility to accommodate a larger co-digestion program.
- EWA should produce as much gas as possible in early years to send as much gas as possible to the pipeline, assuming that RINs values continue to hold the same market value.
- A CO catalyst coupled with gas conditioning offers a viable project with NEM opportunities if a revised air permit can be obtained.

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

4.3 Alternative Selection for Combined SWEET Model (Round 2)

As previously stated, RDTs shall be carried over to the next round of evaluation due to its significant advantages over DAFs. Evaluating mesophilic digestion with Omnivore technology shows promise as a viable option due to its lower capital cost and ability to provide more digester capacity in the future. Thermophilic digestion provides some benefits such as increased HSW loading to the digesters and therefore shall be evaluated further. Centrifuges are the current technology used for sludge dewatering and shall be carried over to the next round provided the existing units are upgraded. Although operation of the dryer may not have shown a competitive NPV over the life-cycle, it offers significant non-economic advantages and therefore operation of one dryer and/or two dryers shall be evaluated further.

The results of the combined 1B model as related to the energy alternatives indicates that regardless of solids processes selected, with HSW co-digestion, a hybrid engine and pipeline injection project offers economic benefit over the engine only base case. For this analysis, it was assumed that RINs end in 2022, however, this is a highly conservative assumption. Greater economic upside can be observed as the RIN program continues beyond 2022 as demonstrated in the energy NPV results.

Section 5: Combined Solids and Energy SWEET Model Results - Round 2

Upon selecting the desired top five alternatives to be evaluated for Round 2, the combined SWEET model was customized in a way that would allow the capital and operating costs for the different projects elements to occur at different times over the life-cycle. The combined SWEET model would incorporate phasing different project elements based on capacity requirements, remaining useful life on equipment, and maximum derivable benefits with respect to RINS and LCFS. This is discussed in greater detail in Section 5.3.

Following are the assumptions made for the combined SWEET model Round 2.

- Capital costs for new projects would occur at the mid-point of construction based on when they are required to come on line during the planning period. For example, if RDTs were required to be in operation by 2021, and assuming it is a 3-year construction project, the capital cost would occur in year 2020.
- Operating costs for new projects would start at the end of construction and carry over all the way through planning period.
- Repair and replacement costs were assumed to occur once over the planning period. Service life of all mechanical equipment was assumed to be 15 years.
- Material disposition costs in terms of pellets and hauling Class B biosolids would be addressed based on operation of one dryer or two dryers. For example, if the second dryer were to be installed in 2026 material dispositions costs would be calculated for both pellets and Class B biosolids hauling. 2026 onward, costs for only pellets would be counted toward material disposition.

5.1 Round 2 Alternatives

Discussions from Workshop 4 held in December 2017 resulted in screening out most of the alternatives that were evaluated in the previous round. The following provided the basis for selecting the top five alternatives to be evaluated on cost and non-cost criteria:

- RDTs were chosen as the preferred thickening technology for all alternatives.
- Mesophilic, thermophilic 15-day, and thermophilic 10-day digestion processes were retained for evaluation.
- Centrifuges were chosen as the preferred dewatering technology for all alternatives; however, the existing centrifuges require mechanical upgrades.
- One and two dryers were retained for evaluation. The alternatives with one dryer would now include provisions for a full-fledged truck loadout that facilitates easy thoroughfare for trucks to haul Class B biosolids, following input from EWA staff.
- Engines and pipeline injection were chosen as the preferred energy alternative due to the significant economic advantages it offers over engines only.
- The baseline energy alternative (engines only) was evaluated with the thermophilic 15-day process and two dryers. This option offers a reliable way to achieve Class B and allows for higher quantity of HSW to be accepted and it offers a different way of utilizing the energy while still being competitive with the other alternatives.

A summary of alternatives considered for Round 2 is shown in Table 5-1 below.

Table 5-1. Overview of Solids Alternatives Evaluated (Round 2)

Alternative No.	Stream Thickened	Thickening Process	SSO Input	Digestion Process	Dewatering Process	Cake	No. of Dryers	Pellets	Pipeline Injection
1	WAS + PS	RDT	Yes	Mesophilic	Centrifuge	Class B	1	Yes	Yes
2	WAS + PS	RDT	Yes	Mesophilic	Centrifuge	None	2	Yes	Yes
3	WAS + PS	RDT	Yes	Thermophilic, 15-day	Centrifuge	Class B	1	Yes	Yes
4	WAS + PS	RDT	Yes	Thermophilic, 15-day	Centrifuge	None	2	Yes	No
5	WAS + PS	RDT	Yes	Thermophilic, 10-day	Centrifuge	None	2	Yes	Yes

5.2 Economic Evaluation of Top Five Alternatives

Table 5-2 shows the breakdown of the capital and running cost along with the overall 20-year NPV for the top five selected alternatives.

Table 5-2. Cost Summary for Top Alternatives				
Number	Description	Capital Cost ($M)	O&M ($M)	Total NPV ($M)
1	RDT-Meso-CD-1D	$62.5	$86.1	$148.6
2	RDT-Meso-CD-2D	$72.2	$93.7	$165.9
3	RDT-Thermo15d-CD-1D	$65.8	$74.4	$140.2
4	RDT-Thermo15d-CD-2D (engines only)	$61.8	$94.1	$155.9
5	RDT-Thermo10d-CD-2D	$73.9	$57.1	$131.0

Figure 5-1 below shows results from the SWEET life-cycle analysis of the selected top five alternatives.

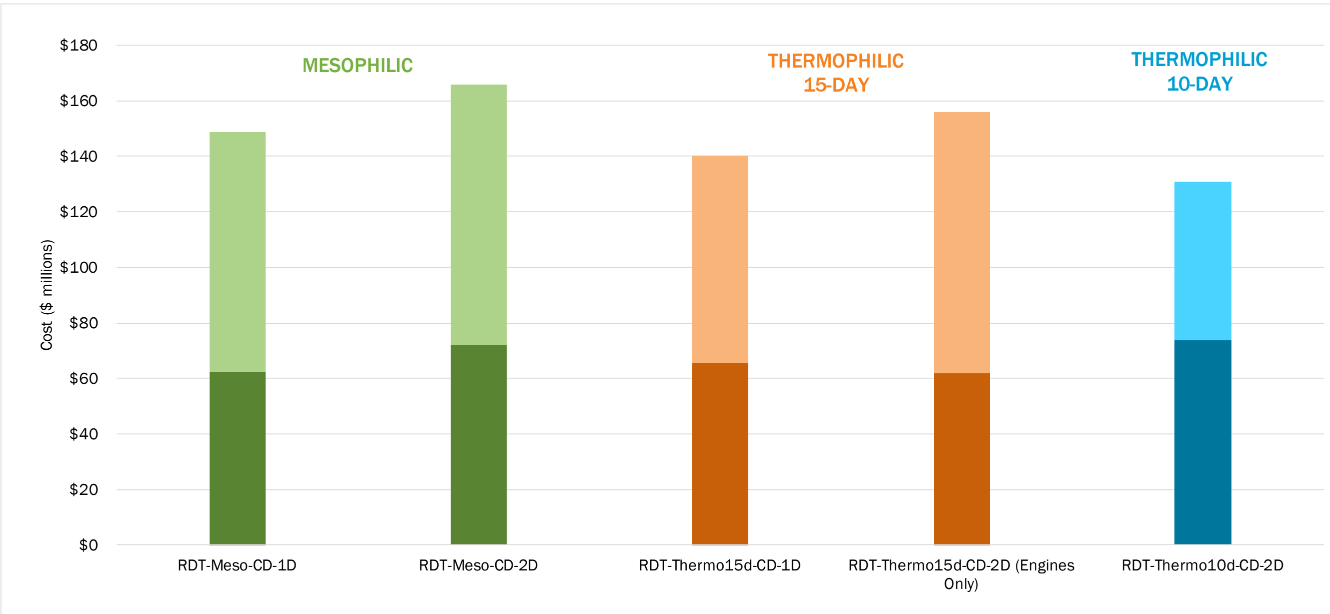

Figure 5-1. Overall NPV for top five alternatives

The results suggest that NPV for the mesophilic digestion options is slightly higher than those for the thermophilic 15-day and 10-day alternatives. The key differentiators between the three digestion scenarios are mainly the quantity of HSW imported. The thermophilic options provide a higher organic loading and therefore can allow for larger quantities of HSW to be digested. This in turn provides more benefits in terms of tipping and energy utilization. The thermophilic 10-day has the lowest NPV and this is attributed mainly to the fact that it can accept the highest quantity of HSW compared to the other alternatives.

Overall, the NPV results of the selected top five alternatives are comparable given the level of analysis; therefore, it was essential to evaluate them based on non-cost criteria as well for EWA to make a decision moving forward.

5.3 Implementation Schedule

The following discusses certain factors that played a key role in determining a phasing timeline for the alternatives and the implementation schedule for the top five alternatives from Round 2 of SWEET.

5.3.1 Digester Excess Capacity Evaluation

The following sections describe excess digester capacity scenarios with existing DAFs and RDTs, respectively. These charts were developed assuming high strength waste at 12 percent solids content would be imported into the mesophilic digesters for co-digestion. The digester capacity available in excess of that required to handle sludge was plotted over time at various service conditions.

5.3.1.1 Digester Excess Capacity (DAF)

Figure 5-2 represents when EWA would run out of digester capacity (mesophilic digestion) under different service conditions while DAFs are in operation. It is evident that at maximum month condition with the largest digester out of service, EWA would run out of digester capacity to import any HSW by 2020. At the annual average condition with the largest digester out of service, digester capacity would be completely utilized by 2031. Only the peak 2-week service condition would allow for importation of HSW over the entire planning period; however, the volume of HSW imported would reduce over time.

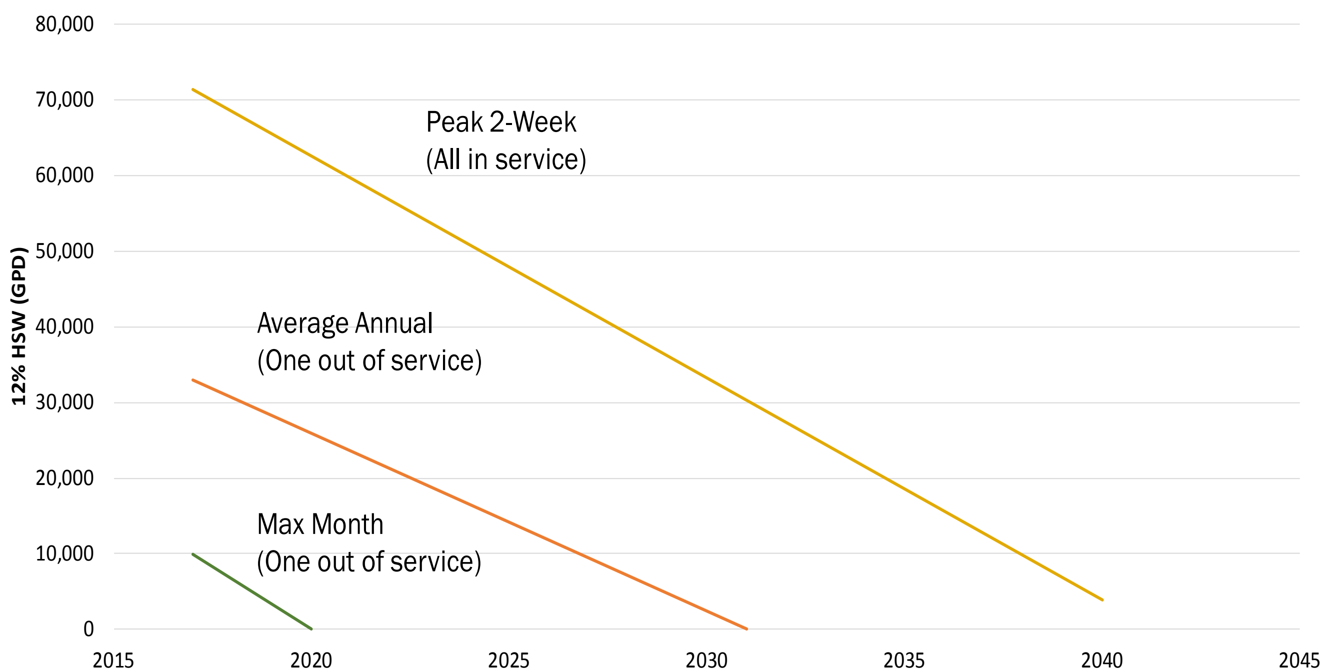

Figure 5-2. Excess digester capacity available for importing 12 percent HSW with DAF

5.3.1.2 Digester Excess Capacity (RDT)

The following Figure 5-3 represents when EWA would run out of digester capacity (mesophilic digestion) under different service conditions if RDTs are installed for co-thickening of PS and WAS. At maximum month condition with the largest digester out of service, EWA would run out of digester capacity to import any HSW by 2026. At the annual average condition with the largest digester out of service, digester capacity would be completely utilized by 2038. Only the peak 2-week service condition would comfortably allow for importation of HSW over the entire planning period.

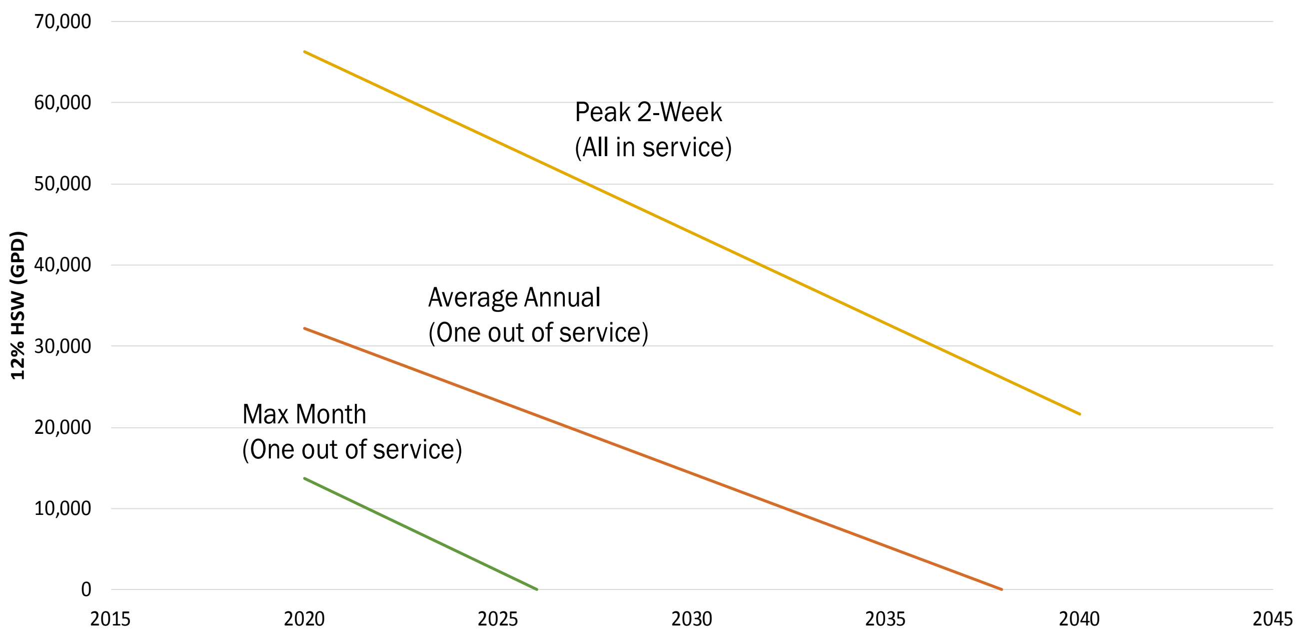

Figure 5-3. Excess digester capacity available for importing 12 percent HSW with RDTs

Based on this evaluation, to successfully implement a food waste program, it is imperative to install RDTs for thickening as it buys EWA more digester capacity without having to build a new digester. It also provides EWA with enough time in the future to make any enhancements to its existing digesters in terms of installing Omnivore or switching to a thermophilic digestion process.

5.3.2 Implementation Schedules for Top Five Alternatives

The previous sections on digester capacity tie in to the development of the implementation schedule for each alternative as they provide information on when the digester projects are required over the planning period whilst maintaining a reliable food-waste program.

The following sections outline a phasing schedule for different project elements listed under each of the selected top five alternatives. The width of each bar in the graphics indicate the project duration and they commonly range from 2 to 3 years. The projects identified in this BEE Plan are divided into two main categories (represented above and below x-axis in the following figures):

- **Core Mission Related Activities.** These projects are imperative to maintaining capacity and redundancy in the overall solids treatment process for EWA over the course of the planning period.
- **Waste Resource Recovery Related Activities.** These projects provide opportunistic pathways for EWA to enhance their energy recovery and utilization.

5.3.2.1 Alternative 1 Implementation Schedule

Alternative 1 includes installation of RDTs for thickening, mesophilic digestion with Omnivore technology, centrifuge dewatering, operation of one dryer, and pipeline injection. Figure 5-4 below represents various projects related to core mission and waste resource recovery for EWA over the 20-year timeline.

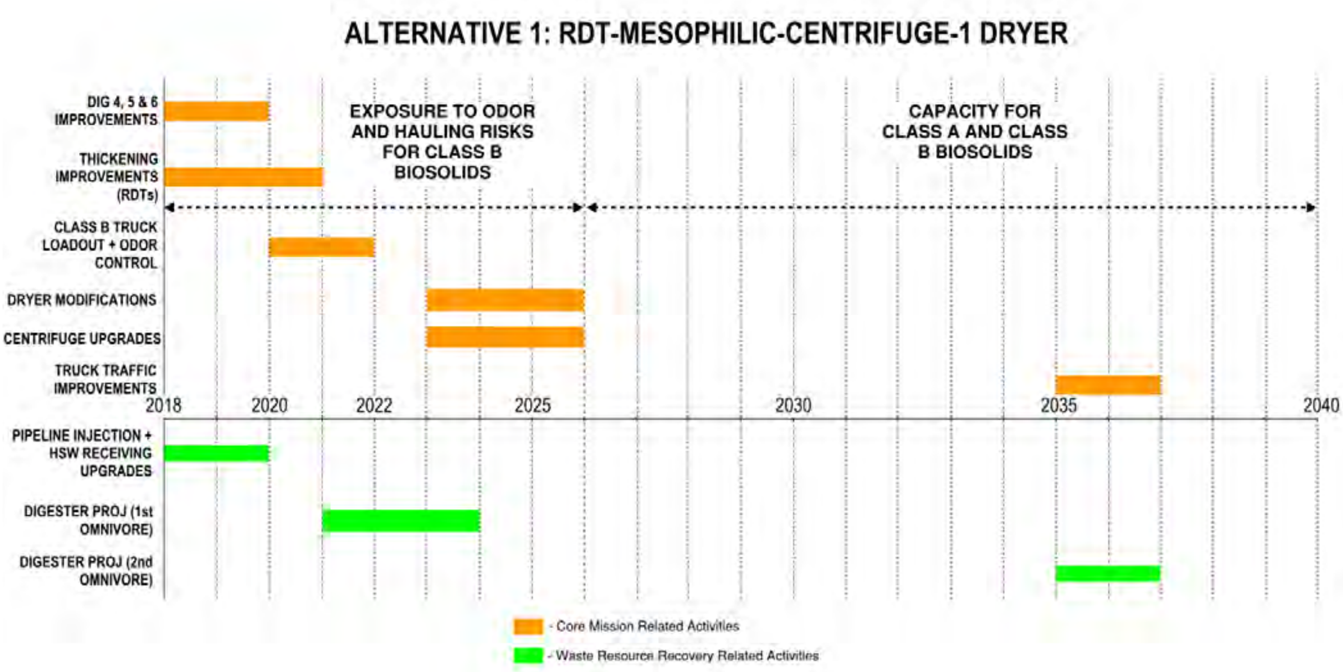

Figure 5-4. Implementation schedule for Alternative 1

Core Mission Projects: Digester improvements for Digesters 4, 5, and 6, and installation of RDTs, must be implemented as early as possible (2018). Upon installation of RDTs (2021), the digester capacity will be adequate to handle sludge loads until 2038. Construction of a new truck loadout with odor control for effective hauling of Class B biosolids should be completed by 2022. Modifications to the existing dryer shall be completed by 2026 due to the limited useful life on the mechanical parts on the unit. The existing centrifuges would be upgraded at the same time. Future projects, such as truck traffic improvements, shall be completed later in the timeline as it is not critical to the effective operation of the overall solids process.

Waste Resource Recovery Projects: Implementation of pipeline injection along with HSW receiving upgrades as early as 2018 will allow EWA to derive maximum benefits from RINS and LCFS as well as accept larger quantities of HSW, Conversion of one of the small digesters into an Omnivore tank shall be completed by 2024 which will provide adequate digester capacity to handle sludge loads beyond 2040. Future conversion of a second small digester to an Omnivore tank may happen later in the timeline (2035); however, it is not critical to the effective operation of the overall solids process.

5.3.2.2 Alternative 2 Implementation Schedule

Alternative 2 includes installation of RDTs for thickening, mesophilic digestion with Omnivore technology, centrifuge dewatering, operation of two dryers, and pipeline injection. Figure 5-5 below represents various projects related to core mission and waste resource recovery for EWA over the 20-year timeline.

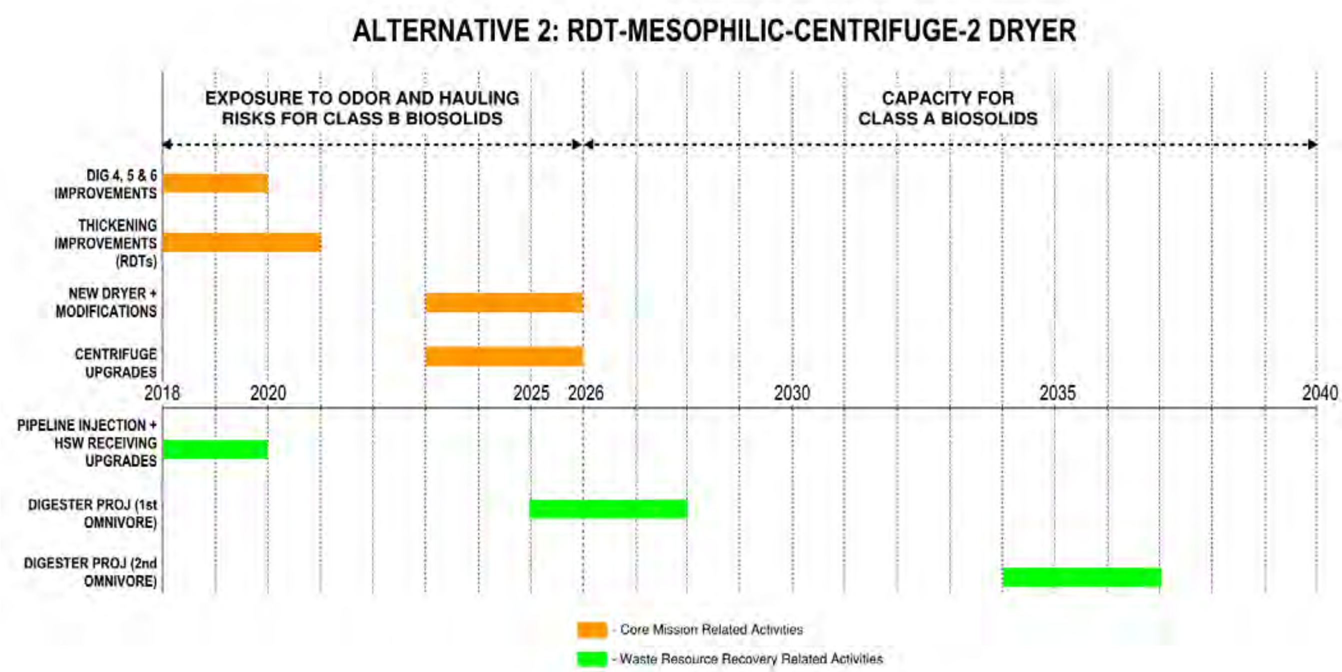

Figure 5-5. Implementation schedule for Alternative 2

Core Mission Projects: Digester improvements for Digesters 4, 5, and 6, and RDTs, must be implemented as early as possible (2018). On installation of RDTs (2021), the digester capacity will be adequate to handle sludge loads until 2038. Until the installation of a second dryer, improvements to the existing truck load out need to be made to facilitate Class B biosolids hauling. Installation of a new second dryer, modifications to the existing dryer and centrifuge upgrades shall be completed by 2026. This implies that beyond 2026, Class A pellets will be the only end-product produced by EWA.

Waste Resource Recovery Projects: Implementation of pipeline injection, along with HSW receiving upgrades, as early as 2018 will allow EWA to derive maximum benefits from RINS and LCFS as well as accept larger quantities of HSW, Conversion of one of the small digesters into an Omnivore tank shall be completed by 2028, which will provide adequate digester capacity to handle sludge loads beyond 2040. Future conversion of a second small digester to an Omnivore tank may happen later in the timeline (2034); however, it is not critical to the effective operation of the overall solids process.

5.3.2.3 Alternative 3 Implementation Schedule

Alternative 3 includes installation of RDTs for thickening, thermophilic 15-day digestion with Omnivore technology, centrifuge dewatering, operation of one dryer and pipeline injection. Figure 5-6 below represents various projects related to core mission and waste resource recovery for EWA over the 20-year timeline.

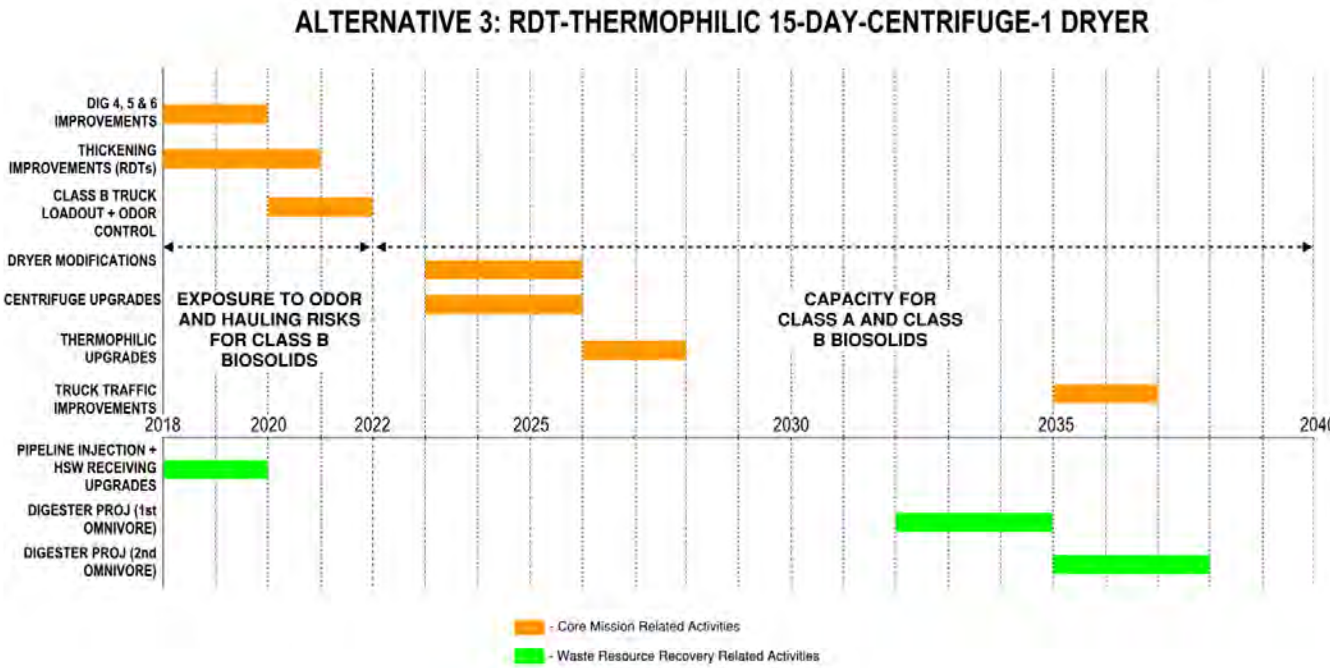

Figure 5-6. Implementation schedule for Alternative 3

Core Mission Projects: Digester improvements for Digesters 4, 5, and 6, and RDTs, must be implemented as early as possible (2018). On installation of RDTs (2021), the digester capacity will be adequate to handle sludge loads until 2038. Construction of a new truck loadout with odor control for effective hauling of Class B biosolids shall be completed by 2022. Modifications to existing dryer shall be completed by 2026 due to the limited useful life on the mechanical parts on the unit. The existing centrifuges shall be upgraded at the same time. In this alternative, the existing mesophilic digesters shall be converted into thermophilic digesters by 2028. Future projects, such as truck traffic improvements, shall be completed later in the timeline as they are not critical to the effective operation of the overall solids process.

Waste Resource Recovery Projects: Implementation of pipeline injection, along with HSW receiving upgrades, as early as 2018 will allow EWA to derive maximum benefits from RINS and LCFS as well as accept larger quantities of HSW, Thermophilic digestion provides more organic loading capacity than traditional mesophilic digestion and therefore pushes out conversion of one of the small digesters into an Omnivore tank by 2035, which will provide adequate digester capacity to handle sludge loads beyond 2040. Future conversion of a second small digester to an Omnivore tank may happen later in the timeline (2035); however, it is not critical to the effective operation of the overall solids process.

5.3.2.4 Alternative 4 Implementation Schedule

Alternative 4 includes installation of RDTs for thickening, thermophilic 15-day digestion with Omnivore technology, centrifuge dewatering, operation of two dryers and engines only with no pipeline injection. Figure 5-7 below represents various projects related to core mission and waste resource recovery for EWA over the 20-year timeline.

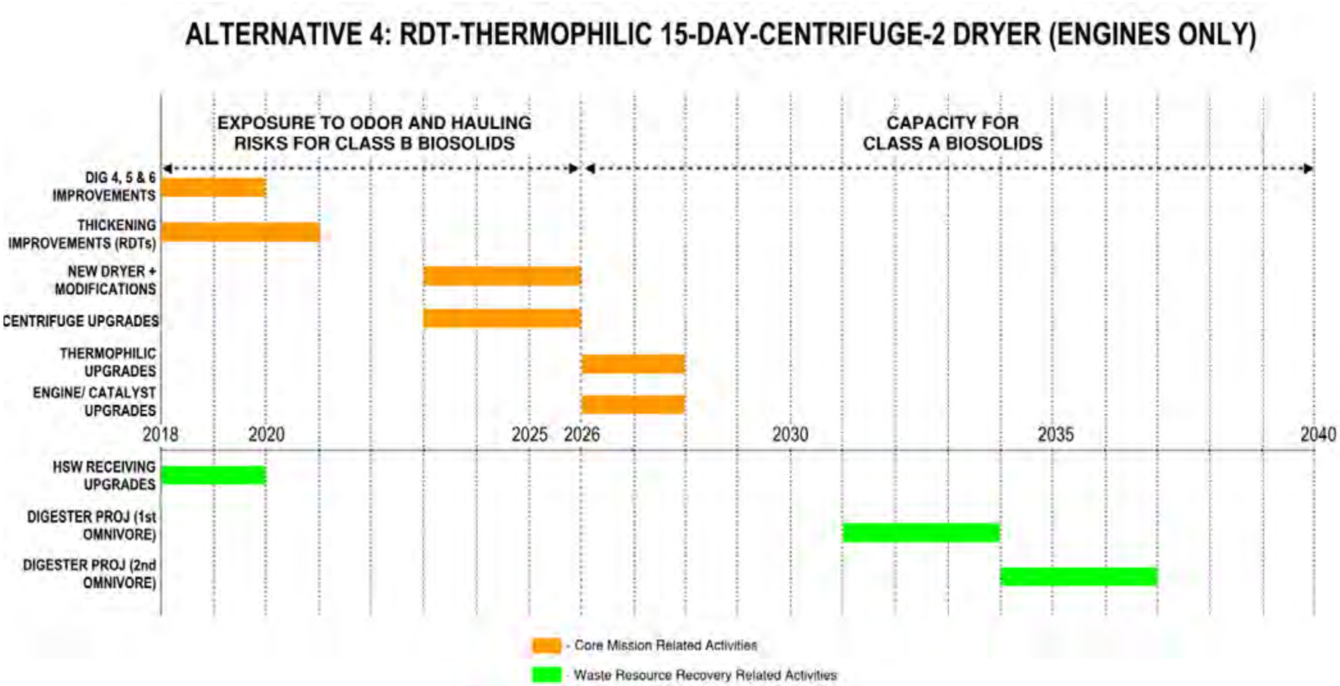

Figure 5-7. Implementation schedule for Alternative 4

Core Mission Projects: Digester improvements for Digesters 4, 5, and 6, and RDTs, must be implemented as early as possible (2018). On installation of RDTs (2021), the digester capacity will be adequate to handle sludge loads until 2038. Until the installation of a second dryer, improvements to the existing truck load out need to be made to facilitate Class B biosolids hauling. Installation of a new second dryer, modifications to the existing dryer, and centrifuge upgrades shall be completed by 2026. This implies that beyond 2026, Class A pellets will be the only product produced by EWA. The existing engines catalyst shall be upgraded by 2026 which will bring about additional engine capacity to beneficially use the increased production of digester gas.

Waste Resource Recovery Projects: Implementation of HSW receiving upgrades as early as 2018 will allow EWA to accept larger quantities of HSW, Thermophilic digestion provides more organic loading capacity than traditional mesophilic digestion and therefore pushes out conversion of one of the small digesters into an Omnivore tank by 2034, which will provide adequate digester capacity to handle sludge loads beyond 2040. Future conversion of a second small digester to an omnivore tank may happen later in the timeline (2034); however, it is not critical to the effective operation of the overall solids process.

5.3.2.5 Alternative 5 Implementation Schedule

Alternative 5 includes installation of RDTs for thickening, thermophilic 10-day digestion with Omnivore technology, centrifuge dewatering, operation of two dryers and pipeline injection. Figure 5-8 below represents various projects related to core mission and waste resource recovery for EWA over the 20-year timeline.

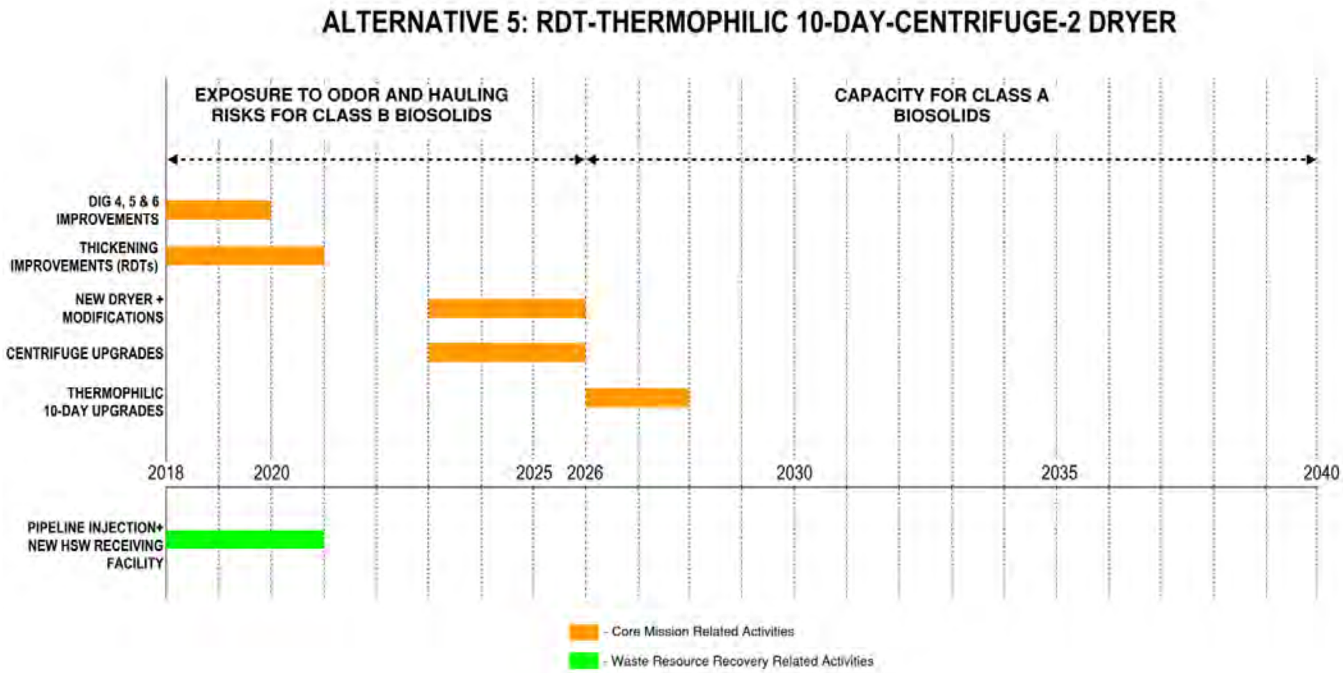

Figure 5-8. Implementation schedule for Alternative 5

Core Mission Projects: Digester improvements for Digesters 4, 5, and 6, and RDTs, must be implemented as early as possible (2018). Upon installation of RDTs (2021), the digester capacity will be adequate to handle sludge loads until 2038. Until the installation of a second dryer, improvements to the existing truck load out need to be made to facilitate Class B biosolids hauling. Installation of a new second dryer, modifications to the existing dryer, and centrifuge upgrades shall be completed by 2026. This implies that beyond 2026, Class A pellets will be the only end-product produced by EWA. In this alternative, the existing mesophilic digesters shall be converted into thermophilic digesters by 2028. On switching to a thermophilic 10-day digestion process, the digester capacity shall be sufficient to handle sludge loads beyond 2040.

Waste Resource Recovery Projects: Implementation of pipeline injection as early as 2018 will allow EWA to derive maximum benefits from RINS and LCFS. Thermophilic digestion with a 10-day retention time allows EWA to accept increased quantities of HSW; therefore, construction of a new HSW receiving facility is required for effective operation. This shall be completed along with the pipeline injection project.

Section 6: Non-Economic Evaluation of Top Five Alternatives

The economic evaluation of the top 5 alternatives indicated that the NPV results of these alternatives were similar and within the anticipated margin of accuracy for this level of analysis. Therefore, a consideration of non-cost criteria and risks is warranted in selection of a preferred alternative for implementation.

The following criteria were used to determine the feasibility of the alternatives from a non-economic standpoint:

- Solids process facilitates access to multiple end-use markets
- Provides consistency with energy sustainability goals
- Provides consistency with overall goals and objectives of EWA
- Addresses neighborhood impacts (encompasses truck traffic, odors, and dust)
- Provides a strategic investment to manage risks
- Addresses impacts to liquids stream process/future nutrient removal and/or recycled water
- Serves as a resource recovery facility (food waste acceptance) in a manner that benefits member agencies' communities
- Maximizes user rate stability in the long term

6.1.1 Mesophilic versus Thermophilic Comparison on Non-Cost Criteria

The following provides information on comparing mesophilic digestion and thermophilic digestion processes from a non-economic standpoint:

- Mesophilic digestion is the current process at EWA.
- Mesophilic digestion process is well known and understood by EWPCF staff.
- Mesophilic digestion and Thermophilic digestion processes are widely used in the industry.
- Mesophilic digestion provides enough digester gas to meet energy recovery goals.
- Conversion to a thermophilic process is easy and can be implemented at any time.
- Implementation of enhanced co-digestion could pay for future upgrades.
- Deferring implementation of the thermophilic process allows time to investigate impacts of thermophilic sludge on the dryer, which was identified as a risk, as no installations of drum dryers coupled with thermophilic digestion could be identified.

The following Table 6-1 ranks the three digestion processes on the non-cost criteria.

Table 6-1. Digestion Process Non-Cost Ranking Matrix

Non-Cost Criteria	Mesophilic	Thermophilic 15-day	Thermophilic 10-day
Meets goals and objectives of EWA	+	+	+
Multiple end-use markets	+	+	+
Energy sustainability	+	+	+
Neighborhood impacts	+	+	+
Risk management	+	0	0
Impact to liquids stream processes	+	+	+
Resource recovery	+	+	+
Long-term user rate stability	+	+	+

From the ranking and analysis of the three digestion processes, it is recommended to continue mesophilic digestion at EWA until capacity or energy recovery goals change.

6.1.2 One-Dryer versus Two-Dryer Comparison on Non-Cost Criteria

The following provides information on comparing one dryer and two dryers from a non-economic standpoint:

- Operation of the dryer greatly reduces truck traffic
- A dryer provides end-use resilience through Class A
- Regional options for dried product can diversify management of end-product
- A dryer reduces offsite odors related to truck traffic and loadout

Table 6-2 below ranks one dryer versus two dryers on non-cost criteria.

Table 6-2. Dryer Non-Cost Ranking Matrix

Non-Cost Criteria	One Dryer	Two Dryers
Meets goals and objectives of EWA	-	+
Multiple end-use markets	0	+
Energy sustainability	+	0
Neighborhood impacts	-	+
Risk management	0	+
Impact to liquids stream processes	0	0
Resource recovery	+	0
Long-term user rate stability	0	0

From the ranking and analysis of dryer options, it is recommended to plan for the implementation of a second dryer in the future.

6.1.3 Engines versus Engines/Pipeline

The following provides information on comparing running engines only versus running engines and injecting gas into the pipeline from a non-cost standpoint:

- Engines are currently used at EWPCF and are a generally accepted form of energy recovery.
- Pipeline injection includes more risk but greater potential to deliver rewards, both economic and environmental.
- Pipeline will pay for gas system upgrades and has potential for large economic benefit. In general, DG is most valuable as CNG (shown on Figure 6-1).
- Pipeline injection allows use of natural gas in the engines and dryer.

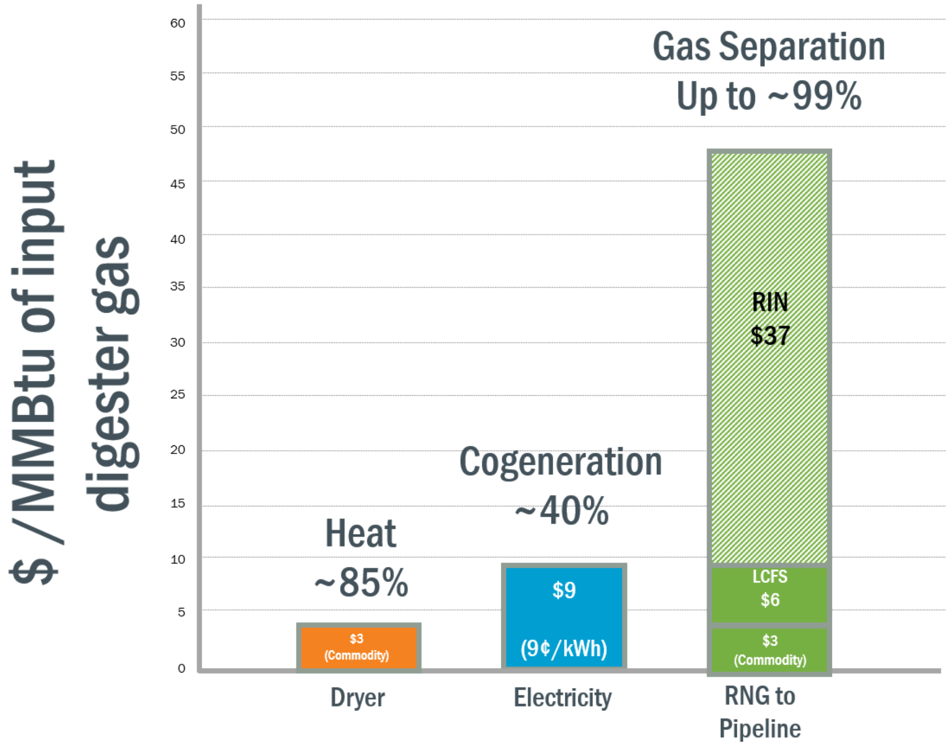

Figure 6-1. Relative value of DG energy based on alternative

The following Table 6-3 ranks one engine versus engines/pipeline on non-cost criteria.

Table 6-3. Engine Utilization Non-Cost Ranking Matrix

Non-Cost Criteria	Engines	Engines + Pipeline
Meets goals and objectives of EWA	+	+
Multiple end-use markets	0	+
Energy sustainability	0	+
Neighborhood impacts	0	0
Risk management	+	-
Impact to liquids stream processes	0	0
Resource recovery	0	+
Long-term user rate stability	0	+

From the ranking and analysis of engine utilization options, it is recommended to consider implementation of gas scrubbing to pipeline to capitalize on market opportunity.

6.1.4 Non-Cost Ranking Recommendations

The following are the recommendations BC is providing based on the non-cost criteria evaluation:

- Continue operation of mesophilic digestion until capacity or energy recovery goals change.
- Plan for implementation of a second dryer in the future.
- Consider implementation of gas scrubbing to pipeline to capitalize on market opportunities.

Section 7: Final Phasing Considerations for the Recommended Alternative (Alternative 2)

Based on ongoing discussion with EWA and interactive project workshops on evaluating EWA's next steps at modifying its existing solids process, key project elements were identified and categorized based on near-, short-, and long-term projects for the recommended alternative. Figure 7-1 represents the implementation schedule of the recommended alternative.

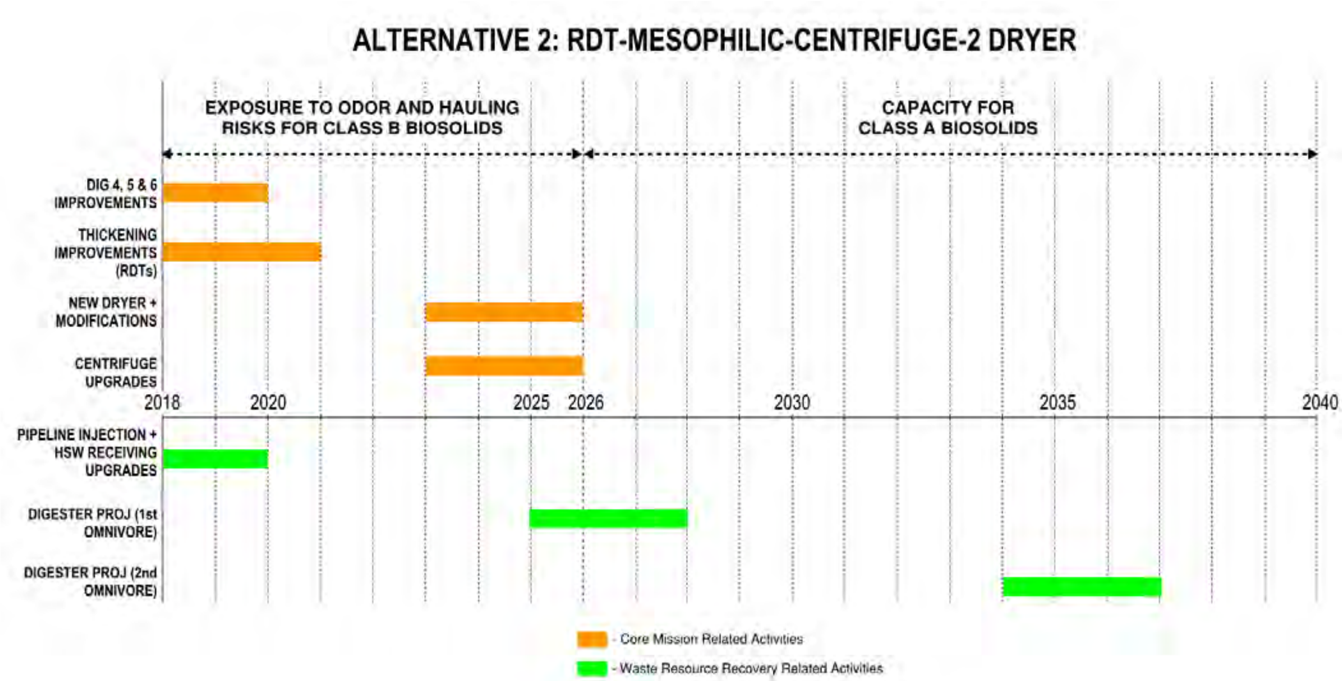

Figure 7-1. Implementation schedule for Alternative 2

For purposes of framing implementation of the capital improvements associated with the recommended alternatives, the BC team divided the projects into near-term (defined as 0 to 5 years), short-term (5 to 10 years) and long-term (10 to 20 years). The near-term projects include those that were generally common among the top five alternatives and address immediate constraints and opportunities associated with the solids and energy processes at EWPCF. These are as follows:

- **Digester Improvements:** This includes mixing upgrades and structural modifications to existing Digesters 4, 5, and 6.
- **High Strength Waste Receiving Upgrades:** This includes mechanical upgrades to existing equipment.
- **Thickening Improvements (RDTs):** This includes installing RDTs for co-thickening of PS and WAS.
- **Pipeline Injection:** This includes sending a portion of the digester gas to the pipeline. This would apply to all alternatives except thermophilic 15-day with two dryers.

The short-term projects address a mixture of aging equipment (such as the dryer and centrifuges) as well as some desirable improvements to support high-strength waste receiving and biosolids beneficial use. The major short-term projects are:

- **Truck Loadout Improvements:** This includes improving the existing truck loadout area and addressing any odor related issues. This project can be customized to the degree of improvement of the loadout found necessary at the time.
- **Dryer Modifications:** This includes modifications to the existing dryer building, replacement of the dryer drum, and other associated mechanical upgrades.
- **Omnivore Project I:** This includes repurposing one of the small digesters (1 or 2) to serve as an Omnivore tank.
- **Centrifuge Upgrades:** This includes replacement of existing centrifuges with larger and more efficient units.

The long-term projects allow for full implementation of the recommended alternative. Most of these projects address the increase in loads to the EWPCF and include:

- **Second Dryer:** This includes installing a second dryer.
- **Omnivore Project II:** This includes repurposing the second small digester to serve as another Omnivore tank in the event of requiring more digester capacity.
- **Truck Traffic Improvements:** This includes modifications to the road within EWA to facilitate easy thoroughfare of trucks in and out of the facility.

Section 8: Summary

A plethora of solids and energy alternatives were evaluated using the SWEET life-cycle analysis tool. This tool allowed for evaluating alternatives based on different process parameters as well as costs. From an economic evaluation standpoint, the SWEET tool was used through multiple rounds to arrive at top five alternatives that performed best on an NPV basis. Regular progress calls and interactive workshops with EWA facilitated the decision making to arrive at the top five alternatives. Implementation schedules were created for each of the top five alternatives. On observing almost comparable NPVs for each of the top five alternatives. a non-economic evaluation was performed on the alternatives and ranked against specific key non-cost criteria. BC's recommendations from the evaluation are mentioned in the following sub-sections.

8.1 Solids Next Steps and Recommendations

BC recommends the following next steps related to solids and energy utilization:

- Implement common project elements such as RDTs, digester improvements, food waste receiving, and truck loadout.
- Continue operation of mesophilic digestion until capacity or energy recovery needs change.
- Plan for implementation of a second dryer.

8.2 Energy Next Steps and Recommendations

BC recommends the following next steps related to the energy alternatives:

- Pursue pipeline injection with SDG&E and initiate capacity analysis to determine pipeline location and feasibility of accepting biomethane. If pipeline injection is feasible, pursue a private-public partnership arrangement to deliver a gas upgrading project without requiring a capital outlay from EWA.
- Pursue a new air permit with CO catalyst to unlock additional engine capacity and initiate discussions with SDG&E for NEM electrical rate schedule to potentially lower power bills and export power.
- Consider construction of gas scrubbing to pipeline to capitalize on market opportunities and offset costs for needed gas conditioning equipment.

Based on the results of the SWEET model effort, multiple energy alternatives can meet the goals of the BEE project; therefore, there is no single recommended alternative. The best steps forward are to initiate conversations with SDG&E and San Diego Air Pollution Control District, and pursue a private-public partnership in parallel to learn more about costs and challenges to implementing the alternatives that show economic benefit and meet the BEE project goals. If the barriers to achieving an alternative are too difficult to overcome (for example, an air permit revision cannot be obtained), EWA can eliminate that as a feasible option.

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Technical Memorandum

FINAL

Prepared for: Encina Wastewater Authority

Project Title: Biosolids, Energy and Emissions

Project No.: 150871.008

Technical Memorandum No. 8

Subject: Grant and Incentive Programs Summary

Date: May 23, 2018

To: Scott McClelland, Assistant General Manager

From: Scott Lacy, Project Manager

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Limitations:

This document was prepared solely for Encina Wastewater Authority in accordance with professional standards at the time the services were performed and in accordance with the contract between Encina Wastewater Authority and Brown and Caldwell dated June 28, 2017. This document is governed by the specific scope of work authorized by Encina Wastewater Authority; it is not intended to be relied upon by any other party except for regulatory authorities contemplated by the scope of work. We have relied on information or instructions provided by Encina Wastewater Authority and other parties and, unless otherwise expressly indicated, have made no independent investigation as to the validity, completeness, or accuracy of such information.

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Executive Summary

The Encina Water Pollution Control Facility (EWPCF) currently has four 750-kilowatt (nameplate) internal combustion engines to utilize some of the digester gas (DG) and sends remaining DG to the biosolids dryer or flare. Brown and Caldwell is evaluating alternative technologies to utilize any DG beyond what is used in the engines. For one of the potential projects identified in Technical Memorandum (TM) 7, where digester gas is converted to renewable natural gas (RNG) and injected to the pipeline, grants and incentives are available. For projects where the output of the existing cogeneration facility is increased—reaching the point of net metering—no funding is likely to be available. The grants and incentive programs discussed in this TM include:

- Renewable Fuel Standard (RFS)
- Low Carbon Fuel Standard (LCFS)
- Pipeline Interconnection Incentive Program
- SoCalGas Biogas Conditioning/Upgrading Services Tariff
- California Energy Commission (CEC)
- CalRecycle
- Self-Generation Incentive Program (SGIP)

Additionally, state and local greenhouse gas (GHG) reduction goals are summarized in this TM.

Section 1: Introduction

Encina Wastewater Authority (EWA) has undertaken a Biosolids Energy and Emissions (BEE) Plan which will be used to update the previous Energy and Emissions Strategic Plan and integrate pertinent recommendations arising from the recently completed Process Master Plan. The BEE Plan has several goals:

1. Provide a comprehensive analysis of all project elements including biosolids treatment, gas use, energy generation, and waste heat;
2. Address capacity limitations in the solids handling process at the EWPCF;
3. Assess which alternative is likely to be the most cost effective and sustainable solution for EWA;
4. Move the EWPCF toward greater energy independence; and
5. Reduce greenhouse gas (GHG) emissions.

1.1 Purpose and Scope

This TM is preceded by TMs 1 to 7 which address the following subjects:

- TM 1 – Baseline Energy Profiles and Projections
- TM 2 – Technology Evaluations for Biosolids Handling
- TM 3 – Technology Evaluations for Alternative Power Production
- TM 4 – Technology Evaluations for Biogas Production
- TM 5 – Technology Evaluations for Waste Heat
- TM 6 – Air Emissions
- TM 7 – Alternatives Development, Evaluation, and Selection

The purpose of TM 8 is to provide an overview of the available funding and incentive opportunities to offset capital cost associated with the potential alternatives. This TM also includes a discussion of the GHG impacts of the preferred alternative identified in TM 7 to describe how the BEE project supports state and local goals.

1.2 Potential Projects

There are several viable projects identified in TM 7 which could offer economic benefit and a reduction in GHG emissions. These projects can be implemented as standalone or in parallel and include the following:

- Engines (current operation)
- Engines with oxidation catalyst for carbon monoxide (CO^2) reduction
- Gas conditioning to remove hydrogen sulfide, moisture, and siloxanes
- Digester gas upgrading to produce RNG for pipeline injection

Section 2: Overviews of Grants and Incentives

An overview of the various grants and incentives for RNG production projects is provided in this section. The overview includes background information, program descriptions, eligibility requirements, and available funding. Additionally, discussions of how each program applies to the RNG production project at EWPCF are included in this section.

2.1 Renewable Fuel Standard

The RFS is a federal program administered by the Environmental Protection Agency (EPA) that incentivizes reducing GHG emissions from petroleum-based transportation fuels and expanding the renewable fuels sector. The program operates in a cap-and-trade manner by requiring a certain quantity of petroleum-based transportation fuels to be replaced by renewable fuels every year. The quantity of non-renewable fuels that must be replaced is set to increase annually through 2022. Petroleum refiners and petroleum fuel importers, known as the obligated parties, are required to demonstrate compliance with the RFS. These organizations can demonstrate compliance by obtaining RFS credits, which are called Renewable Identification Numbers (RINs).

RINs are generated when a gallon of renewable fuel is produced. The obligated parties must obtain a certain amount of RINs each year to offset the quantity of petroleum-based transportation fuel that was sold. RINs can be obtained by physically blending renewable fuels that have attached RINs, purchasing gallons of renewable fuel that have attached RINs, or directly purchasing RINs from the market. Market trading of RINs creates an economic opportunity for organizations that produce renewable transportation fuels because renewable fuel producers can generate additional revenue through the sale of RINs to obligated parties. Renewable fuel producers can sell RINs directly to obligated parties; however, these producers typically hire a RINs broker to assist with credit acquisitions, transactions, and quality assurance.

Four categories of renewable fuels are covered under the RFS program and include biomass-based diesel, cellulosic biofuel, advanced biofuel, and conventional renewable fuel. Each of these categories has a different GHG reduction threshold that the renewable fuel must meet to be eligible for RINs. The categories also have different assigned economic values and are identified by their respective “D codes” (D3 through D7). Typically, RNG produced at a wastewater treatment plant is categorized as D3 (cellulosic) RINs. However, there is an ongoing debate on whether digester gas derived from co-digestion of high strength waste (i.e., food waste, source separated organics; fats, oils and grease; and brewery waste) should be considered a D3 or D5 (advanced biofuel) RIN. The EPA currently categorizes co-digestion product RINs as D5, which is valued two to three times less than a D3 RIN.

Any RNG produced at the EWPCF would be eligible for RINs credits. To obtain these credits, EWA would need to demonstrate the RNG is used as vehicle fuel. Even if RNG is injected to the utility pipeline and is not physically transferred to a vehicle fleet, EWA can reach an agreement with a natural gas fuel purchaser and complete a “paper transaction.” D3 RINs values have fluctuated from less than $1 per RIN to over $2 per RIN; these credits can provide a significant source of income for any renewable natural gas that EWA sends to the utility pipeline.

2.2 Low Carbon Fuel Standard

The LCFS is a program enacted by the State of California (State) to reduce the carbon intensity of transportation fuels used in the state. This program is part of a larger set of California regulations to reduce GHG emissions and cut statewide petroleum use in half by 2030. Like the RFS, the LCFS program operates as a cap-and-trade system. The EWPCF’s potential RNG pipeline injection project is eligible for LCFS credits.

In the case of the LCFS program, carbon intensity, which is a measure of the GHG emissions produced throughout the life-cycle of a fuel, is used to compare the various non-renewable and renewable transportation fuels. Carbon intensity is expressed in grams of CO^2 equivalent per megajoule (g CO_2/MJ) of energy provided by the fuel. A baseline carbon intensity standard was set by the State and this baseline standard will decrease annually until 2020, after which the standard will remain constant until 2030. Entities that produce transportation fuels with higher carbon intensities than the standard operate at a deficit and must obtain LCFS credits from entities that produce transportation fuels with carbon intensities that are lower than the standard.

LCFS credits are generated when a transportation fuel that has a lower carbon intensity than the standard is produced. These credits can be sold to petroleum refiners or other organizations that exceed the carbon intensity compliance limit. To generate and sell LCFS credits, a low carbon fuel producer must register with the California Air Resources Board (CARB) to become a regulated party. Once registered, the renewable fuel producer can track the amount of low carbon intensity fuel that is produced using CARB’s LCFS Reporting Tool. LCFS credits are then received, based on the carbon intensity and the quantity of the fuel. The accounting and transaction processes for LCFS credits are similar to the RINs’ processes.

CARB has compiled a database of LCFS fuel pathways that lists the life-cycle carbon intensities of various types of fuels. According to the database, the carbon intensity of RNG produced at a wastewater treatment plant is between 7.8 g CO_2/MJ and 30.9 g CO_2/MJ, which is significantly lower than gasoline that has a carbon intensity of 96 g CO_2/MJ. LCFS credits typically fluctuate around $1 per diesel gallon equivalent (DGE) based on the carbon intensity values for RNG, but decrease annually.

2.3 Pipeline Interconnection Incentive Program

The California Public Utilities Commission (CPUC) has adopted an incentive program which provides funds for biomethane projects that interconnect to California utility natural gas pipeline systems. Funds provided by the incentive program may be used for up 50 percent of the eligible interconnection costs and each project can apply for up to $3 million in funding. Eligible project costs include the compression equipment for product gas, utility point of receipt, and utility pipeline extension as depicted on Figure 2-1.

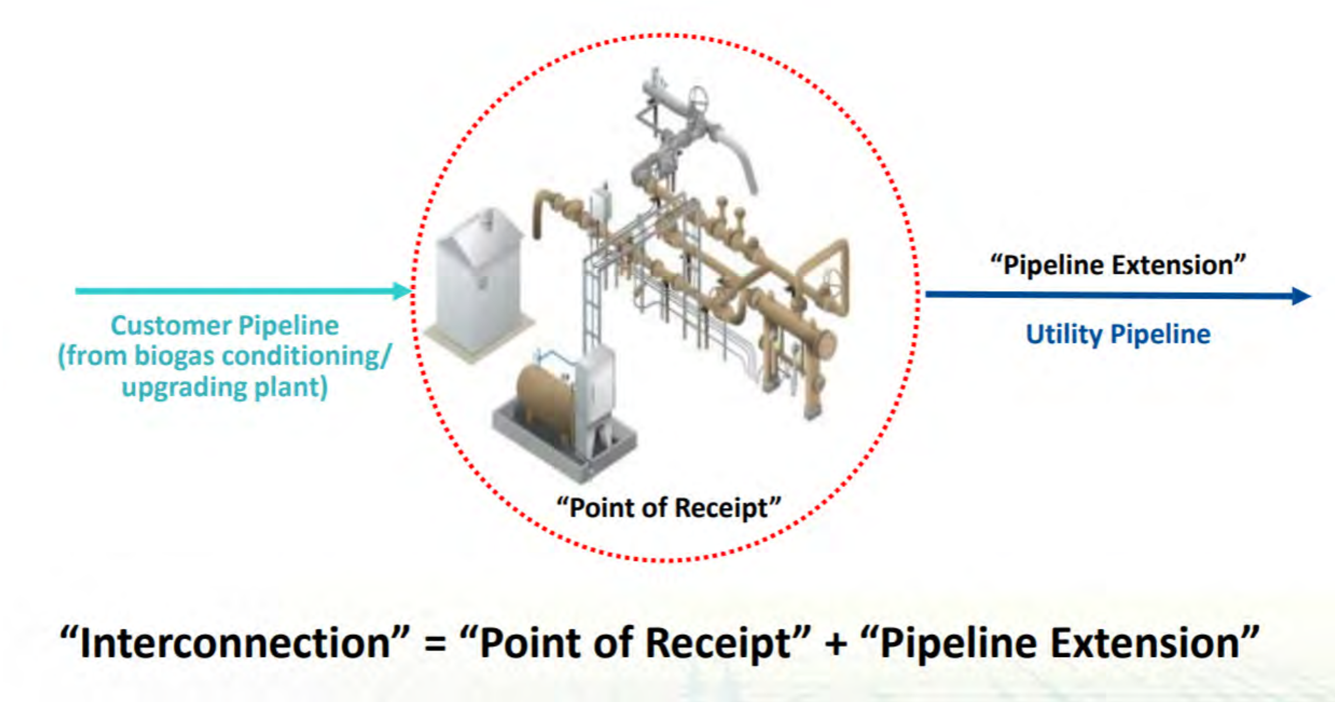

Figure 2-1. Two primary components of an interconnection eligible for CPUC incentive

Source: https://www.socalgas.com/1443741248177/PowerofWaste_SoCalGas_Lucas.pdf

Total program funding for all projects is capped at $40 million, and the program is open to eligible biomethane projects through December 31, 2021. If EWA decides to upgrade digester gas to pipeline quality biomethane, this incentive program may serve as a viable opportunity to reduce interconnection costs.

2.4 SoCalGas Biogas Conditioning/Upgrading Services Tariff

The SoCalGas Biogas Conditioning/Upgrading Services (BCUS) Tariff is an optional tariff service that would allow SoGalGas to plan, design, procure, construct, own, operate, and maintain biogas conditioning and upgrading equipment at a customer's facility. This relationship is illustrated on Figure 2-2. This BCUS tariff was originally investigated as a potential partnering option, but since EWA is not a SoCalGas customer, the EWPCF is not eligible.

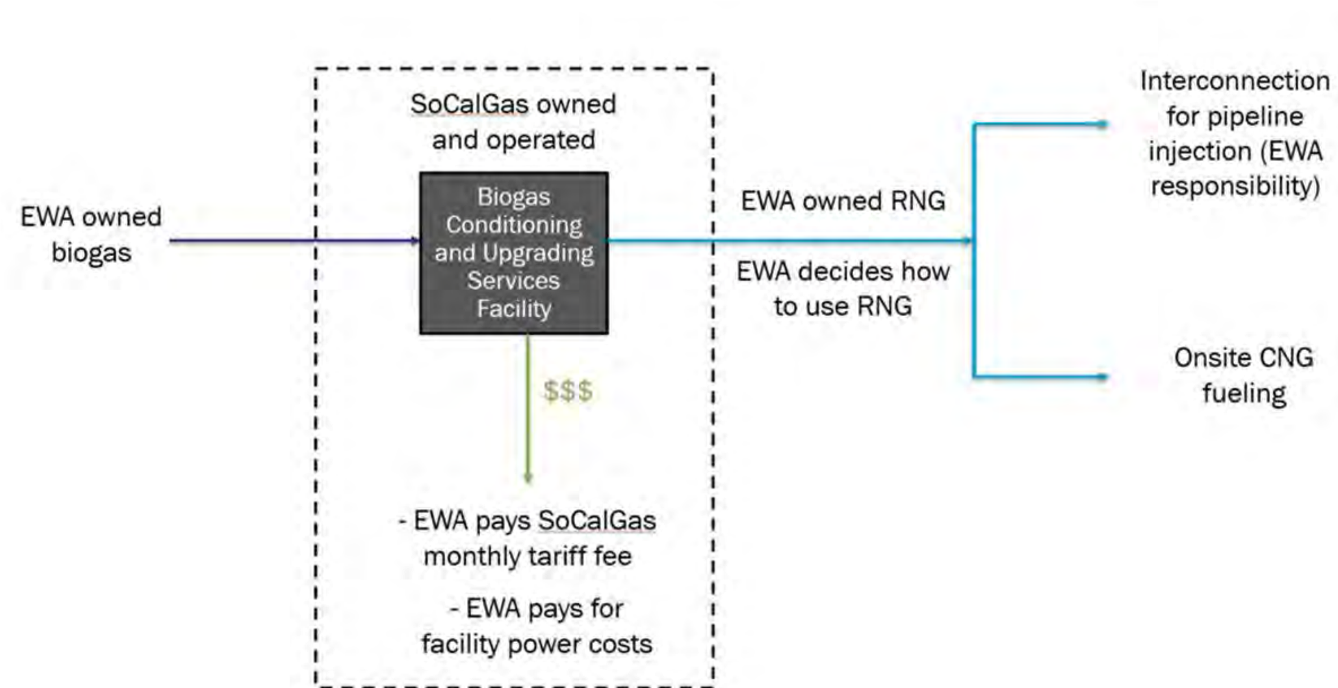

Figure 2-2. SoCalGas BCUS Tariff process to plan, design, procure, construct, own, operate, and maintain biogas conditioning and upgrade equipment process

Under this tariff, the customer would own, operate, and maintain all equipment and facilities upstream of the BCUS receipt point for the untreated biogas and downstream of the BCUS point of service delivery for the treated gas (RNG). The customer would also be responsible for providing electric and natural gas services to run the equipment. This optional tariff will remain open until 2025 for new customers. Actual costs associated with this tariff will require further discussion with SoCalGas and would cover the full cost to provide capital and operation and maintenance services. The program does not bear any risk to SoCalGas ratepayers. A breakdown of assigned responsibilities to the customer and SoCalGas for a theoretical tariff arrangement is shown in Table 2-1.

<table>
<tr><th colspan="8">Table 2-1. SoCalGas BCUS Tariff Responsibilities</th></tr>
<tr><th>Responsible Parties</th><th>Upfront investment for upgrading facility</th><th>On-going mainte-nance of upgrading facility</th><th>Parasitic load (utility costs to run the facility)</th><th>Owns the biogas and RNG</th><th>Determines the contract term</th><th>Interconnection with the utility</th></tr>
<tr><td>SoCalGas</td><td>X</td><td>X</td><td></td><td></td><td rowspan="2">Negotiable (typically 10 to 20 years)</td><td></td></tr>
<tr><td>EWA</td><td></td><td></td><td>X</td><td>X</td><td>X</td></tr>
</table>

2.5 California Energy Commission Grant Opportunities

The CEC has historically offered grants for projects that develop alternative and renewable fuels through the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP). The ARFVTP provides funding to promote changes to transportation fuels and vehicles used in California to ultimately help the state meet its

GHG reduction goals. Each year of the past 3 years, the CEC has allocated approximately $100 million to the ARFVTP and about $20 million has been reserved for biomethane projects. Two ARFVTP funding opportunities for Biofuel Production and Supply have been proposed for 2018 under the Alternative Fuel Production Investment Plan Category. As of February 9, 2018, grant solicitations for these two opportunities have not been released. Additionally, the ARFVTP has been extended through 2024; future biofuel grants can be expected.

2.6 CalRecycle

The California Department of Resources Recycling and Recovery, more commonly known as CalRecycle, oversees State solid waste programs. CalRecycle instituted the Greenhouse Gas Reduction Grant and Loan Programs (Grant and Loan Programs) after the State established the Greenhouse Gas Reduction Fund in 2012. The Grant and Loan Programs incentivize capital projects that reduce GHG emissions by diverting more material from landfills and using the diverted material to produce beneficial products (e.g., RNG). CalRecycle funding opportunities have been released annually; however, State allocations for CalRecycle GHG reduction programs have fluctuated between $25 and $60 million.

The Organics Grant Program is one of the Grant and Loan Programs' overseen by CalRecycle. This program provides funding for digestion and compost projects that divert organic materials from landfills. Although the EWPCF does not have an on-site food waste diversion or pre-processing program, the Organics Grant Program may be applicable if a food waste digestion partnership with Waste Management or another solid waste hauler is pursued.

2.7 Self-Generation Incentive Program

The SGIP provides funding for the installation of technologies that generate or store electrical energy to meet a portion of or all a facility's electrical requirements. The program is overseen by the CPUC and is administered by the State utilities companies. Incentives are provided based on the generating capacity of the equipment. To be eligible for SGIP funding, electricity-generating equipment must be commercially available, interconnected to the local utility's distribution system, and permanently installed on site. Any equipment that has been interconnected for more than 12 months before submission of an application is not eligible for SGIP incentives. Therefore, if cogeneration were expanded at the EWPCF through the installation of gas conditioning and oxidation catalysts and by pursuing a new permit, this project would not be eligible for SGIP funding because new generating equipment is not being installed.

Section 3: State and Local Greenhouse Gas Reduction Goals

The grants and incentives described in Section 2 all serve to incentivize projects that reduce GHG emissions in California. The overarching State and local GHG reduction goals and the impact of RNG production on these GHG goals are discussed in this section.

3.1 Local Greenhouse Gas Reduction Goals

The County of San Diego (County) has completed a Draft Final Climate Action Plan that identifies the County's GHG reduction targets and strategies to meet these targets. GHG reduction goals for the County include:

- Two (2) percent below 2014 levels by 2020
- Forty (40) percent below 2014 levels by 2030
- Seventy-seven (77) percent below 2014 levels by 2050

Currently, the most significant GHG emissions in the County are from on-road transportation, which comprised approximately 45 percent of the total GHG emissions in 2014. The County has identified multiple strategies to reduce GHG emissions from on-road transportation in the Climate Action Plan. One of these strategies is the use of alternative fuels in County projects, and RNG is listed as one of the viable renewable fuels. Additionally, the County also intends to reduce fleet emissions, and expansion of alternative fuels use has been identified as an option to achieve this goal.

3.2 State Greenhouse Gas Reduction Goals

In 2006, the State passed Assembly Bill 32, which set initial GHG emissions reduction goals to achieve 1990 GHG levels by 2020. The State expanded on this initiative through Senate Bill 32, which mandates further reductions of GHG emissions to 40 percent below 1990 levels by 2030. Ultimately, the State hopes to reduce GHG emissions to 80 percent below 1990 levels by 2050.

Every 5 years, since the passage of Assembly Bill 32, the State has developed a Climate Change Scoping Plan. In the 2017 plan, the State identified the transportation sector as the largest emitter of GHGs, making up about 39 percent of statewide emissions. As a key strategy to reduce emissions from the transportation sector, the State aims to promote, research, develop, and deploy low carbon fuels such as RNG. The State has already worked to realize this strategy through the LCFS and ARFVTP programs discussed in Section 2. Additionally, the State aims to integrate the strategies to reduce emissions from the transportation sector with other State initiatives. This integration plan has been advanced through the Short-Lived Climate Pollutants Plan, which requires reductions in methane emissions from landfills, wastewater treatment facilities, and dairies, and incentives for using diverted methane for vehicle fuel and alternative power.

3.3 Impact of Renewable Natural Gas Production on Greenhouse Gas Emissions

The GHG impact of upgrading digester gas to RNG was discussed in TM 6. Within the scope boundary of the EWPCF, upgrading digester gas to RNG for pipeline injection will increase anthropogenic GHG emissions because sending all digester gas to the pipeline will result in increasing natural gas-fired combustion in the engines or purchasing electricity directly from San Diego Gas and Electric. Carbon dioxide in the tail gas from the biogas separation process may also add to GHG emissions.

However, within the scope of local and State GHG reduction goals, upgrading to RNG may have an overall net GHG reduction. RNG produced at the EWPCF may ultimately be used as vehicle fuel, which would supplant a high carbon intensity, petroleum-based fuel (e.g., diesel). Petroleum-based diesel has a much higher carbon intensity than California pipeline natural gas. Thus, the benefits of using RNG to replace diesel for vehicle fuel would outweigh the costs of switching from digester gas to pipeline natural gas in the engines at the EWPCF. Additionally, increasing the availability of RNG for vehicle fuel use aligns with local and State GHG reduction goals of expanding low carbon fuel use.

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Technical Memorandum

Prepared for: Encina Wastewater Authority

Project title: Biosolids, Energy, and Emissions

Project no.: 150871.007.001

Technical Memorandum 9

Subject: High Strength Waste Feasibility Study

Date: November 1, 2018

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$	dollar(s)
$/DGE	dollars per diesel gallons equivalents
$/gal	dollars per gallon
$/lb	dollars per pound
$/MMscf	dollars per million standard cubic feet
$/therm	dollars per therm
$/wet ton	dollars per wet ton
$/year	dollars per year
BC	Brown and Caldwell
AFRF	Alternative Fuel Receiving Facility
BEE	Biosolids Energy and Emissions
d	day(s)
DG	digester gas
DG/lb	digester gas per pound
DGE	Diesel Gallons Equivalents
EBS	Engineered Bio Slurry
EWA	Encina Wastewater Authority
EWPCF	Encina Water Pollution Control Facility
FOG	fats, oil, and grease
gal	gallon(s)
GCS	gas conditioning system
gpd	gallon(s) per day
gpm	gallons per minute
HSW	high-strength waste
IC	internal combustion
kW	kilowatt(s)
kWh	kilowatt hour
lb	pound(s)
LACSD	Sanitation Districts of Los Angeles County
lb	pound(s)
$lb/ft^3/d$	pounds per cubic feet per day
lb VS/ft^3	pounds per volatile solids per cubic feet
LCFS	Low Carbon Fuel Standard
MMBtu/lb	million British thermal units per pound
MMscf	million standard cubic feet
MWh	megawatt hour
NG	natural gas
OLR	organic loading rate
O&M	operations and maintenance
OOS	out of service
RIN	Renewable Identification Number
RNG	renewable natural gas
SB	Senate Bill
scf	standard cubic feet
scfm	standard cubic foot/feet per minute
SCR	selective catalytic reduction
SRT	solids retention time
SSO	source-separated organics
TM	technical memorandum
TOU	time of use
TS	total solids
VS	volatile solids
WM	Waste Management

Section 1: Introduction

Brown and Caldwell recently submitted a comprehensive Biosolids Energy and Emission (BEE) Plan to Encina Wastewater Authority (EWA). Technical Memorandum ™ 7 of the BEE Plan developed various alternative scenarios for solids processing as well as energy production and digester gas (DG) utilization. This TM 9, a high-strength waste (HSW) acceleration study, provides additional capital and life-cycle costs associated with increasing the HSW receiving and renewable energy recovery programs at the Encina Water Pollution Control Facility (EWPCF). EWA has indicated that TM 9 is to be based around the alternative of rehabbing Digesters 1 and 3 to accept HSW and DG upgrading for pipeline injection.

1.1 Purpose and Scope

TM 9 evaluates the feasibility of implementing a HSW or food waste program at the EWPCF's Alternative Fuel Receiving Facility (AFRF) within the next 24 months. This TM provides a summary of the impacts of employing an HSW program upon facilities within the plant such as waste comingling, digestion capacity, solids handling, biogas production and utilization, biosolids disposition, and expected costs.

This TM will be combined with the BEE project. The previous TMs associated with the BEE project include the following:

- TM 1: Baseline Energy Profiles and Projections
- TM 2: Technology Evaluations for Biosolids Handling
- TM 3: Technology Evaluations for Alternative Power Production
- TM 4: Technology Evaluations for Biogas Production
- TM 5: Technology Evaluations for Waste Heat
- TM 6: Air Emissions
- TM 7: Alternatives Development, Evaluation, and Selection
- TM 8: Grant and Incentive Programs Summary

Section 2: Basis of Evaluation

This section summarizes the excess capacity of the existing digesters for HSW and HSW characteristics.

2.1 Existing Digester Capacity

A digester capacity evaluation was performed on the solids handling process, tracking total and volatile solids (VS) through the treatment process at the EWPCF to determine baseline process operating conditions. Calculations were primarily based on 2-year average flows and loads using process data ranging from May 2015 to June 2017 provided by EWA Operations staff. The results of the digester capacity evaluation are summarized in Table 2-1.

Table 2-1. Digester Capacity at EWPCF							
Process	Technology	No. of Units		Condition	Design Loading Rate[1]	Measured Value	Percent of Capacity Used
		Total	Normal Service				
Digestion	Mesophilic Digesters	3	2	Average VS Loading; all units in service	0.15 lb/ft³/d	0.08 lb/ft³/d	40%
				Average VS Loading; two units in service	0.18 lb/ft³/d	0.12 lb/ft³/d	67%
				Peak 2-week[2] VS Loading; all units in service	0.18 lb/ft³/d	0.16 lb/ft³/d	86%
				Hydraulic Loading; two units in service	15 days	19.6 days	77%
				Hydraulic Loading; all units in service	15 days	29.3 days	51%

[1] Digester capacities based on BC standard design criteria for mesophilic digestion.

[2] Peaking condition was applied using the peaking factors developed in BEE Plan TM1-Baseline Energy Profiles

As shown in Table 2-2, the existing digesters have extra capacity for HSW co-digestion at current solids flows and loads. The digester capacity evaluation was based on a digester feed total solids (TS) of 4.6 percent. Due to changes in the operation of the primary clarifiers, the digesters are currently fed at a lower sludge TS. Therefore, there is no excess hydraulic loading capacity for co-digestion under current operation.

The existing HSW receiving facility, AFRF, consists of one HSW transfer pump and two 22,500-gallon storage tanks. Food waste is pre-processed off site to remove contaminants and to process organic waste into a pumpable liquid/slurry. HSW is pumped into each of the two tanks with a single transfer pump. Each tank is equipped with a mixing pump to keep the HSW mixed. HSW is then fed to Digesters 5 and 6 using digester feed pumps. The capacity of the AFRF is summarized in Table 2-2.

Table 2-2. Summary of Existing AFRF Infrastructure		
Condition	Value	Operation
Total storage volume, gallons	45,000	Each tank is 13’ diameter, 25’ height, sloped bottom
Rock trap/grinder, gpm	200	Constant speed
Bypass screening equipment, gpm	200	
Mixing pumps, gpm	300	One per tank
Digester feed pumps, gpm	5-50	One per tank, variable frequency drive control

2.2 HSW Feedstocks Identification and Characteristics

The EWA currently receives approximately 7,100 gallons per day (gpd) of brewery waste and 7,500 gpd of fats, oil, and grease (FOG) for co-digestion. This analysis assumes that EWA will continue to receive the same amount of brewery waste and FOG in the future.

EWA has been researching and evaluating potential HSW for co-digestion to increase gas production. This TM focuses on pre-processed source separated organic (SSO) waste as potential substrate co-digestion at the EWA. This section describes the characteristics of the anticipated pre-processed food waste for EWA’s facility.

The solids concentration of the pre-processed SSO is expected to range from 12 to 15 percent and may vary in pH ranging from 3 to 7, with the expected pH value being around 5. As part of the development of the pre-processed SSO receiving program, it is assumed EWA will develop standards for quality related to minimum screen size, debris removal rates, and presence/absence of manufactured inerts.

Generation of the pre-processed SSO will be accomplished off site by a third party. Raw SSO will be processed into an organic feedstock, nearly free of contaminants, pulped, extruded, and/or slurried into a pumpable liquid. Attachment A summarizes the SSO requirements that the Sanitation Districts of Los Angeles County (LACSD) has developed for its pre-processed SSO receiving program. Other pertinent requirements include recent requirements developed by CalRecycle under its new composting regulations (California Code of Regulations Title 14, Chapter 3.1, Section 17868), included to provide some guidance on physical contamination requirements, which EWA may wish to incorporate (Attachment A).

On the whole, these can be used as a guide for the desired feedstock quality for the partners that will provide EWA with a pumpable slurry that can be offloaded in a contained manner using trucks and hoses.

Characteristics of the SSO used for this evaluation is summarized in Table 2-3.

Table 2-3. Summary of SSO Characteristics

Parameter	Value
TS, %	12
VS, % of TS	85
Specific gravity	1.0

Section 3: Existing HSW Co-Digestion

This section summarizes the existing facility HSW co-digestion capacity, process improvements to accept more HSW, and process impacts.

3.1 Existing Facility HSW Co-Digestion Capacity

Two loading conditions were used to evaluate the process operating conditions and assess conformance with the process limit criteria. The following loading conditions were used to evaluate the digestion system capacity.

- Peak Loading Condition. The peak average 14-day sludge flow and load to the digestion system will be used to assess the peak loading conditions experienced by the digesters with all units in service.
- Service Condition. The service condition is assessed at the average annual flow and load to the digesters assuming the largest unit is out of service. Evaluating at this condition will allow plant staff to take a digester unit out of service at a reduced risk of process upset, assuming that sludge production follows a relatively predictable seasonal pattern. It may be possible to avoid this design condition by identifying alternative sludge offloading or upstream-storage practices; although, these would necessitate use of these alternative plans for sustained periods of time (4 to 8 months at a time for digester cleaning).

Digesters 4, 5, and 6 are used for this evaluation. The following process limit criteria (Table 3-1) were used to evaluate available digester capacities for co-digestion at various conditions.

Table 3-1. Digester Loading Rates for Capacity Evaluation		
Parameter	Peak Condition	Service Condition
Solids flow and load condition	Peak 14-day	Annual average
Number of digesters in service	3	2
Solids retention time, day (min)	15	15
Organic loading rate, lb VS/ft³ (max)	0.18	0.18

The preliminary evaluation results show that the service condition is the limiting condition. The quantities of HSW can be co-digested with the existing digesters are summarized in Table 3-2.

Table 3-2. Maximum Quantities of SSO Can Be Accepted for Co-Digestion with Existing Digesters		
Year	SSO, gpd	Limiting Criterion
2020	36,000	OLR
2021	34,300	OLR
2022	32,600	OLR
2023	30,900	OLR
2024	29,200	OLR
2025	27,500	OLR
2026	25,800	OLR
2027	24,000	OLR
2028	22,300	OLR
2029	20,600	SRT
2030	16,100	SRT
2031	11,600	SRT
2032	7,100	SRT
2033	2,600	SRT
2034	0	SRT
2035	0	SRT
2036	0	SRT
2037	0	SRT
2038	0	SRT
2039	0	SRT
2040	0	SRT

As shown in Table 3-2, the existing digesters will run out of capacity by 2033. There will be no excess digester capacity available for co-digestion starting in 2034.

3.2 Process Improvements to Accept HSW

Two digesters (1 and 3), each with a capacity of 300,000 gallons, could be retrofitted to accept HSW and increase capacity for co-digestion. In order to maximize the production of renewable energy and the utilization of the existing facility, this evaluation was based on retrofitting Digesters 1 and 3 for HSW digestion. The following digester loading criteria were used to evaluate the quantity of HSW can be digested with Digesters 1 and 3 (Table 3-3).

Table 3-3. Digester Loading Criteria for HSW Digestion[1,2]

Condition	Unit	Value
Solids Retention Time	day	15
Organic Loading Rate	lb VS / ft^3	0.5

[1] Assume both Digesters 1 and 3 are in service.

[2] HSW will only be added to Digesters 1 and 3. Existing digesters are for sludge only.

The amount of HSW that can be digested was estimated for two scenarios. Scenario 1 assumes HSW will be digested in Digesters 1 and 3. The three larger digesters will be used for sludge digestion only. This allows one large digester to be taken offline for maintenance and still meet the design hydraulic and organic loading rates.

Scenario 2 assumes one large digester and Digesters 1 and 3 will be used for HSW until 2033. The other two large digesters will be used for sludge digestion. Starting from 2034, all three large digesters will be used for sludge digestion; HSW will be digested in Digesters 1 and 3.

The HSW quantities digested under Scenario 1 are shown in Table 3-4. With both digesters in service, Digesters 1 and 3 can accommodate approximately 40,000 gpd of HSW until 2033, when projected sludge flows and loads exceed the capacity of the three existing digesters. Some sludge needs to be diverted to Digesters 1 and 3, reducing the amount of HSW that can be digested.

Since the EWPCF receives approximately 14,600 gpd of FOG and brewery waste, the additional SSO that can be digested is approximately 25,400 gpd.

Table 3-4. Maximum Quantities of HSW Can Be Accepted with Digesters 1 and 3

Year	FOG and Brewery Waste	SSO	Total HSW, gpd	Limiting Criterion
2020	14,600	25,400	40,000	SRT
2021	14,600	25,400	40,000	SRT
2022	14,600	25,400	40,000	SRT
2023	14,600	25,400	40,000	SRT
2024	14,600	25,400	40,000	SRT
2025	14,600	25,400	40,000	SRT
2026	14,600	25,400	40,000	SRT
2027	14,600	25,400	40,000	SRT
2028	14,600	25,400	40,000	SRT
2029	14,600	25,400	40,000	SRT

Table 3-4. Maximum Quantities of HSW Can Be Accepted with Digesters 1 and 3				
Year	FOG and Brewery Waste	SSO	Total HSW, gpd	Limiting Criterion
2030	14,600	25,400	40,000	SRT
2031	14,600	25,400	40,000	SRT
2032	14,600	25,400	40,000	SRT
2033	14,600	25,400	40,000	SRT
2034	14,600	23,400	38,000	SRT
2035	14,600	18,900	33,500	SRT
2036	14,600	14,400	29,000	SRT
2037	14,600	9,900	24,500	SRT
2038	14,600	5,400	20,000	SRT
2039	14,600	900	15,500	SRT
2040	11,000	0	11,000	SRT

Scenario 2 HSW digested quantities are shown in Table 3-5. With all digesters in service, Digesters 1, 3, and 4 can accommodate approximately 176,700 gpd of HSW until 2033, when projected sludge flows and loads exceed the capacity of the three existing digesters. Digester 4 will be converted to a sludge only digester. HSW will only be digested in Digesters 1 and 3.

Since the EWPCF receives approximately 14,600 gpd of FOG and brewery waste, the additional SSO can be digested is approximately 162,100 gpd.

Table 3-5. Maximum Quantities of HSW Can Be Accepted with Digesters 1, 3 and 4				
Year	FOG and Brewery Waste	SSO	Total HSW, gpd	Limiting Criterion
2020	14,600	162,100	176,700	SRT
2021	14,600	162,100	176,700	SRT
2022	14,600	162,100	176,700	SRT
2023	14,600	162,100	176,700	SRT
2024	14,600	162,100	176,700	SRT
2025	14,600	162,100	176,700	SRT
2026	14,600	162,100	176,700	SRT
2027	14,600	162,100	176,700	SRT
2028	14,600	162,100	176,700	SRT
2029	14,600	162,100	176,700	SRT
2030	14,600	162,100	176,700	SRT
2031	14,600	162,100	176,700	SRT
2032	14,600	162,100	176,700	SRT
2033	14,600	162,100	176,700	SRT
2034	14,600	23,400	38,000	SRT
2035	14,600	18,900	33,500	SRT

Table 3-5. Maximum Quantities of HSW Can Be Accepted with Digesters 1, 3 and 4				
Year	FOG and Brewery Waste	SSO	Total HSW, gpd	Limiting Criterion
2036	14,600	14,400	29,000	SRT
2037	14,600	9,900	24,500	SRT
2038	14,600	5,400	20,000	SRT
2039	14,600	900	15,500	SRT
2040	11,000	0	11,000	SRT

Currently, the AFRF is reaching its capacity receiving an average of 14,600 gpd of FOG and brewery waste. Therefore, a new SSO receiving facility would be required.

Scenario 1 would require a new SSO receiving facility with a capacity slightly larger than the existing AFRF to receive the additional SSO and FOG/brewery waste. Scenario 2 would require a new SSO receiving facility significantly larger than the existing AFRF.

3.3 Solids Process Impacts

Digestion of HSW would have impacts on the solids process downstream of digestion including dewatering and biosolids disposal. A large portion of HSW would be reduced during the digestion process, and the remainder would be transferred to the dewatering process. The increased hydraulic and solids loads to the dewatering process would increase polymer consumption, power consumption of the dewatering process, and may even require more dewatering equipment.

The existing dryer is operating close to its design capacity; excess solids are being hauled off site for Class B land application. Digestion of HSW would increase dewatered biosolids to be disposed of as Class B biosolids, increasing hauling and land application costs.

Section 4: Biogas Production and Utilization

This section provides a summary of the anticipated DG production resulting from the additional HSW, the existing DG management system and equipment capacities, and potential DG management improvements to increase the amount of DG that can be beneficially used.

4.1 DG Production with HSW

DG production estimates for Scenarios 1 and 2 are summarized in Tables 4-1 and 4-2, respectively. These DG production estimates were then used as the basis of evaluation to determine annual operations and maintenance (O&M) costs, sizing of the gas upgrading system, and capital costs.

Table 4-1. Scenario 1: Projected DG Production with HSW with Digesters 1 and 3 for HSW Digestion, scfm				
Year	DG from Sludge	DG from FOG and Brewery Waste	DG from SSO	Total DG
2020	446	143	180	769
2021	456	143	180	779
2022	465	143	180	789
2023	475	143	180	798

Table 4-1. Scenario 1: Projected DG Production with HSW with Digesters 1 and 3 for HSW Digestion, scfm				
Year	DG from Sludge	DG from FOG and Brewery Waste	DG from SSO	Total DG
2024	485	143	180	808
2025	494	143	180	817
2026	504	143	180	827
2027	513	143	180	836
2028	523	143	180	846
2029	532	143	180	855
2030	542	143	180	865
2031	551	143	180	875
2032	561	143	180	884
2033	571	143	180	894
2034	580	143	166	889
2035	590	143	134	867
2036	599	143	102	844
2037	609	143	70	822
2038	618	143	38	800
2039	628	143	6	777
2040	637	143	0	780

Table 4-2. Scenario 2: Projected DG Production with HSW with Digesters 1, 3 and 4 for HSW Digestion, scfm				
Year	DG from Sludge	DG from FOG and Brewery Waste	DG from SSO	Total DG
2020	446	143	1,149	1,710
2021	456	143	1,149	1,719
2022	465	143	1,149	1,729
2023	475	143	1,149	1,738
2024	485	143	1,149	1,748
2025	494	143	1,149	1,757
2026	504	143	1,149	1,767
2027	513	143	1,149	1,776
2028	523	143	1,149	1,786
2029	532	143	1,149	1,796
2030	542	143	1,149	1,805
2031	551	143	1,149	1,815
2032	561	143	1,149	1,824
2033	571	143	1,149	1,834
2034	580	143	166	889
2035	590	143	134	867

Table 4-2. Scenario 2: Projected DG Production with HSW with Digesters 1, 3 and 4 for HSW Digestion, scfm				
Year	DG from Sludge	DG from FOG and Brewery Waste	DG from SSO	Total DG
2036	599	143	102	844
2037	609	143	70	822
2038	618	143	38	800
2039	628	143	6	777
2040	637	143	0	780

4.2 Existing Gas Management and Utilization Capacity

The EWPCF currently utilizes DG in four 750-kilowatt (kW) internal combustion (IC) engines and a biosolids dryer. The current air permit allows up to 280 million standard cubic feet (MMscf) of biogas and natural gas (NG), with a maximum of 28 MMscf of NG as is limited on a carbon monoxide basis. Assuming full DG utilization in the engines, the EWPCF is permitted to fuel the engines on an average of 533 standard cubic feet per minute (scfm), which is approximately 2.5 engines at 100 percent load, on average.

DG that cannot be utilized in the engines can be used in the biosolids dryer, which is capable of operating on a maximum blend of 82 percent DG and 18 percent NG; the dryer can run on 100 percent NG but is limited on DG (Table 4-2).

Table 4-2. Summary of Current Gas Management System and Equipment Capacities		
Equipment	DG Capacity (scfm)	Notes
IC engines	533	Air permit limits DG use up to 28 MMscf on annual basis in 4 x 750 kW units
Thermal dryer	190[1]	Andritz DDS40 can utilize a maximum of 82 percent DG 0.0023 MMBtu/lb solids load to digesters (4.11 scf DG/lb)
Total beneficial use	723	Based on current IC engines air permit and thermal dryer max DG use
Flare (existing)	750	Flare vendor rated capacity

[1] *Based on current baseline digester loading from TM 1, Figure ES-1. With HSW addition, increased loads to the digester will not significantly impact dryer load since most of the load will be volatilized to DG.*

The current gas management system allows for up to 750 scfm of DG production, 723 scfm of which can be used in the engines and thermal dryer. Based on the assumptions outlined in Sections 2 and 3, EWA can accept a maximum of 43,000 gallons per day of HSW at current solids loadings without any major capital improvements. This evaluation also assumes that the existing digester infrastructure, including DG laterals and manifolds, pressure relief valves, and flare are sized adequately for peak instantaneous production.

4.3 Gas Management Improvements to Increase Gas Utilization

If EWA seeks to expand the HSW program by rehabilitating Digesters 1 and 3 and increasing the reliability of the AFRF, additional gas management improvements are required. Once DG production exceeds a threshold of 750 scfm, a new flare is required to safely dispose of DG in an event where the engines and solids dryer are offline, as a minimum. EWA has indicated the preferred use of DG for this evaluation is for pipeline injection, which would benefit from the revenue associated with producing renewable identification numbers

(RINs) under the Federal Renewable Fuel Standard and Credits under California Air Resources Board's Renewable Fuel Standard and Low Carbon Fuel Standard (LCFS).

As such, some alternatives consider all DG will go to pipeline injection with NG purchased to fuel the existing IC engines and provide heat to the thermal dryer. Exhaust treatment with selective catalytic reduction (SCR) will be required for this scenario. Purchasing NG to run the engines with SCR exhaust treatment was demonstrated to provide financial value rather than purchasing electricity from San Diego Gas & Electric (TM 7, alternatives 9 and 9S).

4.3.1 NG Use

It is assumed that the thermal dryer is already operating at capacity as identified in TM 7; therefore, the calculation for energy input is based on the current demands determined in TM 1. This evaluation assumes that the engines will be retrofitted with SCR for exhaust gas treatment in order to meet air permit requirements. Engine output in this analysis is limited to the current and projected plant electricity demands determined in TM 1 since approximately 2.5 engines are required to meet plant demand, the incremental cost of pursuing net electrical metering and exporting power at a lower value is not feasible for the quantity of power that can be exported. This analysis assumes engines will operate to meet full plant demand, thereby eliminating non-coincident demand charges and power costs. A summary of the NG demands for the pipeline injection alternative is included in Table 4-3.

Table 4-3. Summary of NG Demand with Pipeline Injection Alternative

Equipment	Energy Input Required Million therms per year	Notes
IC engines	1.6 to 1.7	NG demand to engines increases as plant power demand increases. Power demand is assumed linear and is based on the predictions in TM1. Ranges between 16,000 to 17,200 MWh per year.
Thermal dryer	0.6	Based on current baseline digester loading from TM 1, Figure ES-1. With HSW addition, increased loads to the digester will not significantly impact dryer load since most of the load will be volatilized to DG.
Total demand	2.2 to 2.3	Varies depending on plant demand.

4.4 Basis of Evaluation for Pipeline Injection

The basis of evaluation for the life-cycle cost analysis is dependent on the quantity of renewable natural gas (RNG) produced. Table 4-4 summarizes the estimated D3, D5, and Diesel Gallons Equivalents (DGE) production on an annual basis. These values will be used to estimate the total revenue from RNG sale. As the regulations are currently written, DG generated from municipal wastewater solids are classified as a D3 cellulosic biofuel RIN. DG generated from food waste, FOG, or any other HSW not coming through the headworks of the plant are classified as a D5 advanced biofuel. Co-mingled waste streams are classified as a D5 RIN; however, by physically separating the digesters with municipal sludge and HSW and metering individual DG production headers, EWA can still maintain the higher value D3 RINs for municipal sludge gas. This approach is recommended and is the basis for the evaluation and costs in this TM. It is assumed that HSW is fed to Digesters 1 and 3 while municipal sludge is sent to the remainder of the digesters, thus separating RINs.

Table 4-4. Scenario 1 RNG Production Estimates for D3 and D5 RINs			
Year	D5 Production, RIN/year [1]	D3 Production, RIN/year [1]	DGE Production, DGE/year [2]
2020	850,000	1,690,000	1,510,000
2021	850,000	1,720,000	1,530,000
2022	850,000	1,760,000	1,550,000
2023	850,000	1,790,000	1,570,000
2024	850,000	1,830,000	1,600,000
2025	850,000	1,860,000	1,620,000
2026	850,000	1,900,000	1,640,000
2027	850,000	1,930,000	1,660,000
2028	850,000	1,960,000	1,680,000
2029	850,000	2,000,000	1,700,000
2030	850,000	2,030,000	1,720,000
2031	850,000	2,070,000	1,740,000
2032	810,000	2,100,000	1,740,000
2033	720,000	2,140,000	1,700,000
2034	620,000	2,170,000	1,670,000
2035	520,000	2,210,000	1,630,000
2036	430,000	2,240,000	1,590,000
2037	330,000	2,280,000	1,560,000
2038	240,000	2,310,000	1,520,000
2039	140,000	2,340,000	1,480,000
2040	50,000	2,380,000	1,450,000

[1] *Based on methane capture efficiency of 99.5% and equipment uptime of 95%. 1 RIN = 77,000 Btu (LHV).*

[2] *Based on methane capture efficiency of 99.5% and equipment uptime of 95%. 1 DGE = 129,000 Btu (LHV).*

Five pipeline injection alternatives were evaluated to determine potential project payback periods with and without the large Digester 4 in service to accept HSW. The initial analysis of the pipeline injection alternatives assumes the following parameters:

- Alternative 1: All DG to Pipeline, NG Engines plus SCR, Large Digester Out of Service (OOS):
  - Scenario 1: Municipal sludge to Digesters 4 through 6, HSW to Digesters 1 and 3
  - Large digester OOS: 25,400 gpd of additional HSW capacity
  - All DG to pipeline: biogas upgrading sized for 800 scfm
  - Engines produce enough power for plant (fueled on NG) and SCR
  - New HSW receiving facility

- Alternative 2: D3 DG to Pipeline, D5 DG to Engines plus SCR, Large Digester OOS:
  - Scenario 1: Municipal sludge to Digesters 4 through 6, HSW to Digesters 1 and 3
  - Large digester OOS: 25,400 gpd of additional HSW capacity
  - D3 gas to pipeline, D5 gas to engines
  - Biogas upgrading/gas conditioning sized for 800 scfm
  - Engines produce enough power for plant (supplement with NG) and SCR
  - New HSW receiving facility
- Alternative 2.5 – D3 DG to Pipeline, D5 DG to Engines:
  - Scenario 1: Municipal sludge to Digesters 4 through 6, HSW to Digesters 1 and 3
  - Large digester OOS: 25,400 gpd of additional HSW capacity
  - D3 gas to pipeline, D5 gas to engines
  - Biogas upgrading sized for 1200 scfm; no separate gas conditioning. Engines get pipeline quality gas.
  - Engines produce enough power for plant and oxidation catalyst installed (time of use [TOU] peak shaving)
  - New HSW receiving facility
  - Assume Alternative 2 operating costs
- Alternative 2.75 – D3 DG to Pipeline, D5 DG to Engines plus SCR:
  - Scenario 1: Municipal sludge to Digesters 4 through 6, HSW to Digesters 1 and 3
  - Large digester OOS: 25,400 gpd of additional HSW capacity
  - D3 gas to pipeline, D5 gas to engines
  - Biogas upgrading sized for 1,200 scfm; no separate gas conditioning. Engines get pipeline quality gas
  - Engines produce enough power for plant and SCR plus oxidation catalyst installed (TOU peak shaving)
  - New HSW receiving facility
  - Assume Alternative 2 operating costs
- Alternative 3 – D3 DG to Pipeline, D5 DG to Engines, Large Digester in Service:
  - Scenario 2: Municipal sludge to Digesters 5 and 6, HSW to Digesters 1, 3, and 4
  - Large digester in service: import HSW to produce enough DG for engines at 60,000 gpd
  - D3 gas to pipeline, D5 gas to engines
  - Biogas upgrading sized for 600 scfm; gas conditioning system (GCS) sized for 650 scfm
  - Engines produce enough power for plant and oxidation catalyst installed
  - New HSW receiving facility

- Alternative 4 – All DG to Pipeline, Large Digester OOS:
  - Scenario 1: Municipal sludge to Digesters 4 – 6, HSW to Digesters 1 and 3.
  - Large digester OOS: 25,400 gpd of additional HSW capacity
  - All DG to pipeline: biogas upgrading sized for 800 scfm
  - Engines produce enough power for plant (fueled on NG) and SCR installed
  - New HSW receiving facility
- Alternative 5 – All DG to Pipeline, Large Digester in Service:
  - Scenario 2: Municipal sludge to Digesters 5 and 6, HSW to Digesters 1, 3, and 4
  - Large digester in service for HSW until 2033: 162,000 gpd of additional HSW capacity
  - All DG to pipeline: biogas upgrading 2,000 scfm capacity
  - Engines produce enough power for plant (fueled on NG) and SCR
  - New, large HSW receiving facility and site truck traffic modifications

Section 5: Present Worth Cost Analysis

A present worth cost analysis was performed to identify capital and operating costs associated with upgrading EWPCF to accept HSW for co-digestion and beneficially reuse the gas through NG pipeline injection. The analysis uses an escalation rate of 2.0 percent and a discount rate of 2.5 percent performed over a 20-year period from 2020 to 2040. The analysis was ultimately used to determine the payback period (year) required for the net benefits derived from HSW and DG upgrades to pay off the capital investments.

The following sections describe the various assumptions made on capital costs, operating costs, and benefits along with results from the present worth cost analysis.

5.1 Capital Costs

Conservative cost assumptions were made on the following items which are required for the upgrade of EWPCF to accept HSW and beneficially reuse the gas through NG pipeline injection. Detailed cost estimating was not performed, but costs available from relevant projects around Southern California were used.

Table 5-1 provides a summary of capital cost investments required for the various alternatives.

Table 5-1. Summary of Project Cost for Proposed Alternatives[1]

	Alt 1 - All DG to Pipeline, NG Engines + SCR, Large Digester OOS	Alt 2 - D3 DG to Pipeline, D5 DG to Engines, SCR, Large Digester OOS	Alt 2.5 - D3 DG to Pipeline, D5 DG to Engines	Alt 2.75 - D3 DG to Pipeline, D5 DG to Engines	Alt 3 - D3 DG to Pipeline, D5 DG to Engines, Large Dig in Service	Alt 4 -All DG to Pipeline, Large Digester OOS	Alt 5 - All DG to Pipeline, Large Digester in Service
Biogas Upgrading System	$16.9M (800 scfm)	$16.9M (800 scfm)	$21.2M (1,200 scfm)	$21.2M (1,200 scfm)	$15.3M (650 scfm)	$24.0M (2,000 scfm)	$24.0M (2,000 scfm)
Oxidation Catalyst			$1.0M	$1.0M	$1.0M		
Gas Conditioning					$4.3M (600 scfm)		

Table 5-1. Summary of Project Cost for Proposed Alternatives[1]							
	Alt 1 - All DG to Pipeline, NG Engines + SCR, Large Digester OOS	Alt 2 - D3 DG to Pipeline, D5 DG to Engines, SCR, Large Digester OOS	Alt 2.5 - D3 DG to Pipeline, D5 DG to Engines	Alt 2.75 - D3 DG to Pipeline, D5 DG to Engines	Alt 3 - D3 DG to Pipeline, D5 DG to Engines, Large Dig in Service	Alt 4 -All DG to Pipeline, Large Digester OOS	Alt 5 - All DG to Pipeline, Large Digester in Service
SCR	$4.0M	$4.0M		$3.9M		$4.0M	$4.0M
HSW Receiving Facility	$2.0M	$2.0M	$3.0M	$3.0M	$3.0M	$6.0M	$6.0M
Digesters 1 & 3 Upgrades[2]	$5.5M	$5.5M	$5.5M	$5.5M	$5.5M	$5.5M	$5.5M
Project Cost	$28.4M	$28.4M	$30.7M	$34.6M	$29.1M	$39.5M	$39.5M

[1] *Costs shown in 2020 dollars.*

[2] *Cost for digester upgrades includes new mixing systems, heat exchangers, sludge circulation pumps mechanical piping and minor structural upgrades.*

5.2 Operating Costs

To the best degree possible, the following operating cost estimates reflect the actual operating parameters and unit costs at EWPCF. Information was requested during the BEE Plan from EWA staff for chemicals; utilities such as water, NG, electricity; and biosolids trucking/dispositions costs and used in this evaluation.

The following Table 5-2 summarizes the unit costs used for operating cost analysis.

Table 5-2. Summary of Unit Costs		
Parameter	Unit	Cost
NG (Dryer)	$/therm	0.31
NG (Engine)	$/therm	0.31
Cogen O&M	$/kWh	0.015
SCR O&M	$/kWh	0.015
DG upgrading O&M	$/MMscf	540
Class B cake hauling and disposal	$/wet ton	48
Dewatering polymer	$/lb	1.2
Electricity	$/kWh	0.09
Non-coincident demand charge	$/year	0[1]

[1] *Current non-coincident demand charges are $255K annually. Evaluation assumes that since there is engine redundancy and SCR will eliminate air permit restrictions on fuel usage, EWA will be able to run engines to meet plant demand, thereby eliminating the noncoincident demand charge.*

5.3 Benefits

Table 5-3 shows a summary of benefit cost assumptions used in the analysis. The D3, D5, and LCFS credit values all assumed a 1 percent deflation value over the 20-year analysis as there is uncertainty in future values of these attributes. Note that these values have been updated to reflect the current market value for RINs since the initial BEE project. The current market values as of October 2018 are approximately 25 percent higher than the values used in the analysis; actual revenue is de-rated to account for broker and verification fees that subtract from the RIN revenue. A sensitivity analysis was performed for the various alternatives that determined potential project payback period with low and high RIN and LCFS credit values. For the high incentive values, the D3 RIN was assumed to be $2.25/RIN, the D5 RIN was $0.75/RIN; the LCFS credit value was $1.15/DGE. These are included in the Attachment B calculations.

Table 5-3. Summary of Benefit Unit Costs

Parameter	Unit	Cost
HSW Tip Fee	$/gal	0.04
D3 RIN value	$	1.50
D5 RIN value	$	0.25
LCFS value	$/DGE	0.80
NG Sale	$/therm	0.25

Attachment B includes a calculation that summarizes the annual estimated revenue from pipeline injection for RINs, LCFS, the commodity value of the fuel, and HSW tipping fees. These economic benefits range from $4 to $10 million annually, with the D3 RIN revenue generating approximately half of the total.

5.4 Results

The results from the present worth analysis for the presented alternatives are provided in Table 5-1.

All alternatives offset capital and operating investments and provided a positive return on investment ranging from $5.6 million to 22.5 million over a 20-year project life.

Table 5-1. Summary of Proposed Alternatives

	Alt 1 - All DG to Pipeline, NG Engines + SCR, Large Digester OOS	Alt 2 - D3 DG to Pipeline, D5 DG to Engines, Large Digester OOS	Alt 2.5 - D3 DG to Pipeline, D5 DG to Engines	Alt 2.75 - D3 DG to Pipeline, D5 DG to Engines	Alt 3 - D3 DG to Pipeline, D5 DG to Engines, Large Digester in Service	Alt 4 -All DG to Pipeline, Large Digester OOS	Alt 5 - All DG to Pipeline, Large Digester in Service
Description	• All DG to pipeline: biogas upgrading sized for 800 scfm • Engines produce enough power for plant (fueled on NG) and SCR • Large digester OOS: 25,400 gpd of additional HSW capacity • New HSW receiving facility	• D3 gas to pipeline, D5 gas to engines • Biogas upgrading/gas conditioning sized for 800 scfm • Engines produce enough power for plant (supplement with NG) and SCR • Large digester OOS: 25,400 gpd of additional HSW capacity • New HSW receiving facility	• D3 gas to pipeline, D5 gas to engines • Biogas upgrading sized for 1200 scfm; no separate gas conditioning. Engines get pipeline quality gas. • Engines produce enough power for plant and oxidation catalyst installed (TOU peak shaving) • Large digester OOS: 25,400 gpd of additional HSW capacity • New HSW receiving facility • Assume Alt 2 operating costs	• D3 gas to pipeline, D5 gas to engines • Biogas upgrading sized for 1200 scfm; no separate gas conditioning. Engines get pipeline quality gas • Engines produce enough power for plant and SCR + oxidation catalyst installed (TOU peak shaving) • Large digester OOS: 25,400 gpd of additional HSW capacity • New HSW receiving facility • Assume Alternative 2 operating costs	• D3 gas to pipeline, D5 gas to engines • Biogas upgrading sized for 600 scfm; GCS sized for 650 scfm • Engines produce enough power for plant and oxidation catalyst installed • Large digester in service: import HSW to produce enough DG for engines at 60,000 gpd • New HSW receiving facility	• All DG to pipeline: biogas upgrading sized for 800 scfm • Engines produce enough power for plant (fueled on NG) and SCR installed • Large digester OOS: 25,400 gpd of additional HSW capacity • New HSW receiving facility	• All DG to pipeline: biogas upgrading 2,000 scfm capacity • Engines produce enough power for plant (fueled on NG) and SCR • New, large HSW receiving facility and site truck traffic modifications • Large digester in service for HSW until 2033: 162,000 gpd of additional HSW capacity
Project Cost	$28.4M	$28.4M	$30.7M	$34.6M	$29.1M	$39.5M	$39.5M
20-year Net Present Cost	($21.9M)	($11.7M)	($9.5M)	($5.6M)	($20.4M)	($10.8M)	($22.5M)
Payback Period – Current RIN Value	11.5 years	15.9 years	16.1 years	18.1 years	12.8 years	16 years	11.9 years
Payback Period - low RIN	20 years (change to $1.1/D3, LCFS to $0.65/DGE)	20 years (change to $1.16/D3)	20 years (change to $1.22/D3)	20 years (change to $1.34/D3)	20 years (change to $0.90/D3)	20 years ($1.19/D3)	20 years ($0.85/D3)
Payback Period - high RIN	6.3 years	8.5 years	10.0 years	11.3 years	7.8 years	8.8 years	5.7 years
Class B Hauling Volume (2020), wtpd	18	18	18	18	41	18	118
Class B Hauling Cost (2020)	$324,000	$324,000	$324,000	$324,000	$714,000	$324,000	$2,067,000
HSW Volume (2020), gal/day	25,400	25,400	25,400	25,400	56,000	25,400	162,000
Tipping Fee HSW Revenue (2020)	$371,000	$371,000	$371,000	$371,000	$818,000	$371,000	$2,366,000

Section 6: Waste Hauler Coordination

EWA and Brown and Caldwell have held calls with waste haulers near the EWPCF would take interest in providing a HSW feedstock. Potential waste haulers include Waste Management (WM), EDCO, and Republic Services amongst others. Legislation in California is continuing to evolve in favor of diverting organics from landfills. While current Assembly Bill 1826 requires businesses that generate a specified amount of organic waste per week to arrange for recycling services, there is no penalty for non-compliance. The main legislation that will drive a shift in California's approach to organics waste management is the upcoming Short-Lived Climate Pollutants Senate Bill (SB) 1383, which will require a 50 percent reduction in organic waste disposal in comparison to 2014 levels by 2020 and 75 percent by 2025. SB 1383 will also include compliance requirements and penalties beginning in 2020 (with increasing requirements in both 2022 and 2025).

WM has organics pre-processing facilities in Los Angeles and Orange counties, and an upcoming facility in El Cajon. The El Cajon station will be a "next-generation" CORe v3.0 facility with an Engineered Bio Slurry (EBS) product with minimal grit capable of processing up to 250 tons per day. This station will service Carlsbad, El Cajon, and San Diego. WM is working with Orange County Sanitation District and LACSD as potential offtakers. WM will be pursuing the upcoming organics diversion grant money; EWA should consider applying for money to cover the cost of a feed-in-station or at least join the WM El Cajon application as a "letter of interest" partner.

WM provided their EBS specification for feedstock for the CORe product which is also verified by a third party. Several of the key parameters and values from the specification include the following:

- TS: 14 to 16 percent
- Total VS: 88 to 92 percent
- Total physical inerts: 0.05 to 0.25 percent dry weight

The CORe product is a high quality, pre-processed, pumpable slurry, making it a good HSW feedstock for EWA to pursue. It is recommended that if EWA plans to move ahead with the HSW acceleration project, the agency should continue to coordinate with other potential haulers to ensure that pre-processing is performed off site and the material is pumpable and free of contaminants to ensure EWA will not be responsible for waste handling at the plant.

Section 7: Summary

Due to changes in the operation of the primary clarifiers, Digesters 4, 5, and 6 are currently fed with sludge at a lower sludge TS. Therefore, there is no excess capacity for co-digestion under current operation. The results of this evaluation suggest that the digesters will have capacity for HSW co-digestion after the design and construction of the new rotary drum thickening process. The available digester for co-digestion will decrease as more solids are produced in the future. Existing digesters will run out of capacity by 2033.

Two scenarios were evaluated for the EWPCF to import additional HSW for digestion. Both scenarios assume the smaller digesters, Digesters 1 and 3, will be retrofitted to accept HSW. Scenario 1 assumes all HSW, including FOG, brewery waste, and SSO would be sent to Digesters 1 and 3. With both small digesters in service, Digesters 1 and 3 can accommodate approximately 40,000 gpd of HSW until 2033, when projected sludge flows and loads exceed the capacity of Digesters 4, 5 and 6. Some sludge needs to be diverted to Digesters 1 and 3, reducing the amount of HSW that can be digested. The EWPCF currently receives approximately 14,600 gpd of FOG and brewery waste. Therefore, additional SSO can be digested is approximately 25,400 gpd.

Scenario 2 assumes one large digester and Digesters 1 and 3 will be used for HSW digestion. Under this scenario, the additional SSO can be digested is estimated to be approximately 162,100 gpd until 2033. Starting in 2034, all three large digesters will be used for sludge digestion only. HSW will be digested in Digesters 1 and 3.

The existing AFRF is reaching its capacity with FOG and brewery waste. Therefore, a new receiving facility will be required to accept SSO.

A net present worth evaluation was conducted to evaluate the payback period for the capital expenditure for several co-digestion and energy recovery alternatives. All alternatives offset capital and operating investments and provided a positive return on investment ranging from $5.6 million to 22.5 million over a 20-year project life.

Section 8: Recommended Next Steps

This analysis identified that there is a financial incentive for EWA to further investigate the potential for HSW co-digestion and energy recovery through gas upgrade to pipeline quality. To this end, it is recommended that further investigations are conducted to refine the project elements, costs, and assumptions.

Specifically, the following next steps are recommended to further refine project elements and increase confidence in project economics:

- Analyze potential funding and grant options for the project.
- Schedule a discussion with Southern California Gas Company to obtain a firm interconnection cost and begin negotiation of contract terms.
- Attend a site tour of an existing biogas upgrade installations to assist with technology selection.
- Review local air quality management district permitting requirements to determine pretreatment and tail gas treatment needs.
- Request firm proposals from upgrade system vendors.
- Develop detailed site layouts to confirm footprint requirements
- Integrate project benefits into member communities’ climate action plans.
- Continue dialogue with waste management companies and discuss quality and capacity criteria.

Attachment A: LACSD SSO Specifications

Detailed Summary of food waste characteristics from LACSD

ITEM	VALUE	REFERENCE
pH	3.0 – 7.0	LACSD SSO SPECIFICATION
Volatile Acids (Acetic Acid Equivalents)	Less than 8,000 mg/L	LACSD SSO SPECIFICATION
Total Solids	12.0 – 15.0%	LACSD SSO SPECIFICATION
Volatile Solids (% of Total Solids)	85 – 95%	LACSD SSO SPECIFICATION
Total COD	Greater than 180,000 mg/L	LACSD SSO SPECIFICATION
Total BOD	Greater than 80,000 mg/L	LACSD SSO SPECIFICATION
Specific Gravity@25 degC	0.95 – 1.10	LACSD SSO SPECIFICATION
Kinematic Viscosity@25 degC	Less than 200 cps	LACSD SSO SPECIFICATION
Ammonia as Nitrogen (NH3-N)	Less than 600 mg/L	LACSD SSO SPECIFICATION
Total Kjeldahl Nitrogen (TKN)	Less than 7,500 mg/L	LACSD SSO SPECIFICATION
Total Carbon	Greater than 9,000 mg/L	LACSD SSO SPECIFICATION
Electrical Conductivity	Less than 15 millimho/cm	LACSD SSO SPECIFICATION
Arsenic	Less than 1 mg/L	LACSD SSO SPECIFICATION
Calcium	Less than 3,000 mg/L	LACSD SSO SPECIFICATION
Chloride	Less than 3,000 mg/L	LACSD SSO SPECIFICATION
Chromium	Less than 2 mg/L	LACSD SSO SPECIFICATION
Magnesium	Less than 500 mg/L	LACSD SSO SPECIFICATION
Mercury	Less than 1 mg/L	LACSD SSO SPECIFICATION
Nickel	Less than 5 mg/L	LACSD SSO SPECIFICATION
Potassium	Less than 3,000 mg/L	LACSD SSO SPECIFICATION
Sodium	Less than 3,000 mg/L	LACSD SSO SPECIFICATION
Total Heavy Metals (Ag, As, Ba, Cd, Co, Cr, Cu, Hg, Mo, Ni, Pb, Sb, Se, Ti Sr, Sn, V, and Zn)	Less than 50 mg/L	LACSD SSO SPECIFICATION
Specific Heavy Metal Limits		
Cadmium (Cd)	1 mg/L	Ordinance OCSD-48
Chromium (Cr)	35 mg/L	Ordinance OCSD-48
Copper (Cu)	25 mg/L	Ordinance OCSD-48
Lead (Pb)	10 mg/L	Ordinance OCSD-48
Nickel (Ni)	10 mg/L	Ordinance OCSD-48

ITEM	VALUE	REFERENCE
Zinc (Zn)	50 mg/L	Ordinance OCSD-48
Physical Contamination [1] (greater than 4 millimeters)	0.5% by dry weight	Title 14 -Section 17868.3.1 – Physical Contamination Limits
Film Plastic (greater than 4 millimeters)	20% by dry weight of Physical Contamination	Title 14 -Section 17868.3.1 – Physical Contamination Limits

Note:

1. "Physical Contaminants" means human-made inert products contained within feedstocks, including, but not limited to, glass, metal, and plastic (Title 14 Section 17381).

Attachment B: Calculations

ALTERNATIVE 1

Risk adjustments (+/- percent):

Year of analysis	2020	**Benefits**	0%
Escalation rate	2.00%	**Capital costs**	0%
Discount rate	2.50%	**Running costs**	0%

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

	Year																				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Expressed in 2020 dollars, unescalated -- dollars																					
Capital Outlays																					
BUS - 800 scfm + Interconnection	16,945,847																				
SCR	4,000,000																				
HSW Receiving Facility	2,000,000																				
Dig 1&3 Improvements	5,500,000																				
Total capital outlays	28,445,847	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,372,328	2,396,794	2,420,224	2,442,619	2,463,979	2,484,303	2,503,592	2,521,846	2,539,065	2,555,248	2,570,417	2,584,550	2,597,648	2,609,710	2,620,736	2,630,726	2,639,681	2,647,599	2,654,482	2,660,329
D5 RINs	157,772	156,145	154,519	152,892	151,266	149,639	148,013	146,386	144,760	143,133	141,507	139,880	138,254	136,627	124,604	99,415	74,804	50,772	27,316	4,439	0
LCFS	1,287,788	1,290,332	1,292,547	1,294,433	1,295,988	1,297,215	1,298,111	1,298,678	1,298,916	1,298,824	1,298,402	1,297,657	1,296,583	1,295,172	1,273,585	1,226,510	1,180,215	1,134,694	1,089,947	1,045,974	1,034,880
Natural Gas Sale	566,196	573,224	580,252	587,280	594,308	601,336	608,364	615,392	622,420	629,448	636,476	643,508	650,539	657,571	654,398	637,898	621,398	604,899	588,399	571,899	574,295
HSW Tipping Fee	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	342,280	276,419	210,558	144,697	78,836	12,975	0
Total benefits	(4,729,422)	(4,762,869)	(4,794,952)	(4,825,669)	(4,855,021)	(4,883,009)	(4,909,631)	(4,934,889)	(4,958,782)	(4,981,310)	(5,002,473)	(5,022,302)	(5,040,767)	(5,057,858)	(5,004,576)	(4,860,978)	(4,717,702)	(4,574,742)	(4,432,097)	(4,289,768)	(4,269,504)
Annual Running Costs:																					
Engine O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
SCR O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
Biogas Upgrading O&M	207,470	210,046	212,621	215,196	217,771	220,347	222,922	225,497	228,073	230,648	233,223	235,800	238,376	240,953	239,790	233,744	227,698	221,652	215,606	209,560	210,438
NC Demand																					
Natural Gas Purchased - Dryer	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835
Natural Gas Purchased - Engine	490,537	492,376	494,216	496,055	497,895	499,734	501,574	503,413	505,253	507,092	508,932	510,771	512,611	514,450	516,290	518,130	519,969	521,809	523,648	525,488	527,327
HSW Facility O&M	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Dig 1 & 5 O&M	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Dewatering Polymer	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	6,882	5,558	4,233	2,909	1,585	261	0
Dewatering Power	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	9,575	7,733	5,890	4,048	2,205	363	0
Class B Hauling	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	298,956	241,431	183,906	126,382	68,857	11,332	0
Total running costs	2,406,574	2,412,789	2,419,003	2,425,218	2,431,433	2,437,648	2,443,862	2,450,077	2,456,292	2,462,507	2,468,722	2,474,938	2,481,154	2,487,370	2,463,528	2,400,430	2,337,333	2,274,235	2,211,137	2,148,039	2,140,600
Net Benefit/(cost)	26,122,999	(2,350,081)	(2,375,948)	(2,400,451)	(2,423,588)	(2,445,361)	(2,465,769)	(2,484,812)	(2,502,490)	(2,518,803)	(2,533,751)	(2,547,365)	(2,559,613)	(2,570,489)	(2,541,048)	(2,460,548)	(2,380,369)	(2,300,507)	(2,220,960)	(2,141,729)	(2,128,903)
Expressed in escalated dollars with sensitivity adjustments																					
Capital Outlays																					
BUS - 800 scfm + Interconnection	16,945,847	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCR	4,000,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dig 1&3 Improvements	5,500,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	28,445,847	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,419,774	2,493,624	2,568,361	2,643,969	2,720,432	2,797,729	2,875,841	2,954,745	3,034,417	3,114,833	3,195,990	3,277,835	3,360,335	3,443,457	3,527,166	3,611,423	3,696,190	3,781,424	3,867,079	3,953,109
D5 RINs	157,772	159,268	160,761	162,251	163,735	165,214	166,687	168,152	169,609	171,058	172,496	173,924	175,339	176,742	164,412	133,800	102,691	71,092	39,014	6,466	0
LCFS	1,287,788	1,316,139	1,344,766	1,373,662	1,402,820	1,432,230	1,461,884	1,491,773	1,521,887	1,552,215	1,582,745	1,613,474	1,644,381	1,675,444	1,680,469	1,650,721	1,620,183	1,588,846	1,556,713	1,523,786	1,537,777
Natural Gas Sale	566,196	584,688	603,694	623,226	643,298	663,924	685,117	706,892	729,264	752,249	775,861	800,121	825,041	850,638	863,464	858,527	853,047	847,004	840,378	833,149	853,372
HSW Tipping Fee	370,840	378,257	385,822	393,538	401,409	409,437	417,626	425,979	434,498	443,188	452,052	461,093	470,315	479,721	451,631	372,023	289,051	202,610	112,597	18,902	0
Total benefits	(4,729,422)	(4,858,127)	(4,988,668)	(5,121,038)	(5,255,231)	(5,391,236)	(5,529,042)	(5,668,636)	(5,810,003)	(5,953,126)	(6,097,986)	(6,244,602)	(6,392,911)	(6,542,879)	(6,603,432)	(6,542,236)	(6,476,394)	(6,405,743)	(6,330,126)	(6,249,382)	(6,344,258)
Discounted Benefits (in 2020$)	(4,729,422)	(4,739,636)	(4,748,286)	(4,755,393)	(4,760,980)	(4,765,067)	(4,767,676)	(4,768,827)	(4,768,540)	(4,766,837)	(4,763,737)	(4,759,291)	(4,753,487)	(4,746,338)	(4,673,428)	(4,517,189)	(4,362,660)	(4,209,823)	(4,058,661)	(3,909,162)	(3,871,716)
Annual Running Costs:																					
Engine O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
SCR O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
Biogas Upgrading O&M	207,470	214,246	221,211	228,368	235,723	243,281	251,046	259,025	267,223	275,645	284,298	293,187	302,319	311,698	316,398	314,589	312,581	310,366	307,939	305,290	312,700
NC Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	186,835	190,572	194,383	198,271	202,236	206,281	210,407	214,615	218,907	223,285	227,751	232,306	236,952	241,691	246,525	251,455	256,485	261,614	266,847	272,184	277,627
Natural Gas Purchased - Engine	490,537	502,224	514,182	526,418	538,937	551,747	564,854	578,264	591,984	606,022	620,385	635,080	650,115	665,497	681,234	697,334	713,806	730,658	747,898	765,536	783,580
Dig 1 & 5 O&M	600,000	612,000	624,240	636,725	649,459	662,448	675,697	689,211	702,996	717,056	731,397	746,025	760,945	776,164	791,687	807,521	823,671	840,145	856,948	874,087	891,568
Dewatering Polymer	7,456	7,605	7,757	7,913	8,071	8,232	8,397	8,565	8,736	8,911	9,089	9,271	9,456	9,645	9,081	7,480	5,812	4,074	2,264	380	0
Dewatering Power	10,374	10,582	10,793	11,009	11,229	11,454	11,683	11,917	12,155	12,398	12,646	12,899	13,157	13,420	12,634	10,407	8,086	5,668	3,150	529	0
Class B Hauling	323,901	330,379	336,987	343,726	350,601	357,613	364,765	372,061	379,502	387,092	394,834	402,730	410,785	419,001	394,466	324,934	252,464	176,965	98,345	16,509	0
Total running costs	2,306,574	2,359,044	2,412,691	2,467,540	2,523,618	2,580,952	2,639,570	2,699,500	2,760,772	2,823,414	2,887,458	2,952,937	3,019,879	3,088,317	3,118,625	3,096,076	3,071,378	3,044,454	3,015,223	2,983,606	3,032,225
Discounted Running Costs (in 2020$)	2,306,574	2,301,507	2,296,434	2,291,356	2,286,273	2,281,185	2,276,093	2,270,996	2,265,894	2,260,788	2,255,678	2,250,565	2,245,449	2,240,328	2,207,136	2,137,734	2,068,957	2,000,800	1,933,258	1,866,328	1,850,479
		0																			
Net escalated benefit/(cost)	26,022,999	(2,499,082)	(2,575,977)	(2,653,498)	(2,731,613)	(2,810,284)	(2,889,473)	(2,969,136)	(3,049,232)	(3,129,712)	(3,210,528)	(3,291,665)	(3,373,032)	(3,454,562)	(3,484,807)	(3,446,160)	(3,405,016)	(3,361,289)	(3,314,903)	(3,265,776)	(3,312,033)
Life cycle cost analysis																					
PVs in 2020	26,022,999	(2,438,129)	(2,451,852)	(2,464,037)	(2,474,707)	(2,483,882)	(2,491,583)	(2,497,831)	(2,502,646)	(2,506,049)	(2,508,059)	(2,508,726)	(2,508,038)	(2,506,010)	(2,466,293)	(2,379,455)	(2,293,704)	(2,209,023)	(2,125,403)	(2,042,833)	(2,021,238)
Cumulative Benefits Payback	26,022,999	23,584,870	21,133,018	18,668,981	16,194,275	13,710,393	11,218,810	8,720,978	6,218,332	3,712,283	1,204,224	(1,304,502)	(3,812,540)	(6,318,550)	(8,784,842)	(11,164,297)	(13,458,000)	(15,667,023)	(17,792,426)	(19,835,259)	(21,856,497)
NPV as of 2020	(21,856,497)																				

ALTERNATIVE 2

		Risk adjustments (+/- percent):	
Year of analysis	2020	Benefits	0%
Escalation rate	2.00%	Capital costs	0%
Discount rate	2.50%	Running costs	0%

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

	Year																				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Expressed in 2020 dollars, unescalated -- dollars																					
Capital Outlays																					
BUS 800 scfm	16,945,847																				
SCR	4,000,000																				
HSW Receiving Facility	2,000,000																				
Dig 1&3 Improvements	5,500,000																				
Total capital outlays	28,445,847	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,372,328	2,396,794	2,420,224	2,442,619	2,463,979	2,484,303	2,503,592	2,521,846	2,539,065	2,555,248	2,570,417	2,584,550	2,597,648	2,609,710	2,620,736	2,630,726	2,639,681	2,647,599	2,654,482	2,660,329
LCFS	747,102	755,220	763,010	770,469	777,599	784,399	790,870	797,011	802,823	808,305	813,457	818,280	822,780	826,950	830,790	834,301	837,482	840,333	842,854	845,046	846,908
Natural Gas Sale	328,475	335,503	342,531	349,559	356,587	363,615	370,643	377,671	384,699	391,727	398,755	405,787	412,818	419,850	426,881	433,913	440,944	447,975	455,007	462,038	469,070
HSW Tipping Fee	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	342,280	276,419	210,558	144,697	78,836	12,975	0
Total benefits	(3,793,243)	(3,833,891)	(3,873,174)	(3,911,092)	(3,947,645)	(3,982,833)	(4,016,656)	(4,049,115)	(4,080,208)	(4,109,937)	(4,138,300)	(4,165,324)	(4,190,988)	(4,215,288)	(4,209,661)	(4,165,368)	(4,119,710)	(4,072,685)	(4,024,296)	(3,974,541)	(3,976,306)
Annual Running Costs:																					
Engine O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
SCR O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
Biogas/GCS Upgrading O&M	207,470	210,046	212,621	215,196	217,771	220,347	222,922	225,497	228,073	230,648	233,223	235,800	238,376	240,953	239,790	233,744	227,698	221,652	215,606	209,560	210,438
Natural Gas Purchased - Dryer	186,835	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844	186,845	186,846	186,847	186,848	186,849	186,850	186,851	186,852	186,853	186,854	186,855
Natural Gas Purchased - Engine	195,775	197,614	199,454	201,294	203,133	204,973	206,812	208,652	210,491	212,331	214,170	216,010	217,849	219,689	234,181	265,198	296,215	327,232	358,249	389,266	396,853
HSW Facility O&M	100,000	100,001	100,002	100,003	100,004	100,005	100,006	100,007	100,008	100,009	100,010	100,011	100,012	100,013	100,014	100,015	100,016	100,017	100,018	100,019	100,020
Dig 1 & 5 O&M	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Dewatering Polymer	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	6,882	5,558	4,233	2,909	1,585	261	0
Dewatering Power	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	9,575	7,733	5,890	4,048	2,205	363	0
Class B Hauling	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	298,956	241,431	183,906	126,382	68,857	11,332	0
Total running costs	2,111,812	2,118,029	2,124,245	2,130,462	2,136,679	2,142,896	2,149,113	2,155,329	2,161,546	2,167,763	2,173,980	2,180,198	2,186,416	2,192,634	2,181,447	2,147,529	2,113,610	2,079,692	2,045,774	2,011,855	2,010,166
Net Benefit/(cost)	26,764,416	(1,715,863)	(1,748,929)	(1,780,630)	(1,810,966)	(1,839,937)	(1,867,544)	(1,893,785)	(1,918,662)	(1,942,174)	(1,964,320)	(1,985,126)	(2,004,572)	(2,022,654)	(2,028,214)	(2,017,839)	(2,006,099)	(1,992,993)	(1,978,522)	(1,962,685)	(1,966,140)
Expressed in escalated dollars with sensitivity adjustments																					
Capital Outlays																					
BUS 800 scfm	16,945,847	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCR	4,000,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dig 1&3 Improvements	5,500,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	28,445,847	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,419,774	2,493,624	2,568,361	2,643,969	2,720,432	2,797,729	2,875,841	2,954,745	3,034,417	3,114,833	3,195,990	3,277,835	3,360,335	3,443,457	3,527,166	3,611,423	3,696,190	3,781,424	3,867,079	3,953,109
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LCFS	747,102	770,325	793,835	817,628	841,698	866,040	890,648	915,515	940,635	965,999	991,599	1,017,428	1,043,483	1,069,748	1,096,210	1,122,859	1,149,683	1,176,669	1,203,803	1,231,072	1,258,460
Natural Gas Sale	328,475	342,213	356,369	370,955	385,981	401,460	417,404	433,826	450,737	468,150	486,081	504,545	523,553	543,120	563,261	583,989	605,322	627,274	649,862	673,103	697,013
HSW Tipping Fee	370,840	378,257	385,822	393,538	401,409	409,437	417,626	425,979	434,498	443,188	452,052	461,093	470,315	479,721	451,631	372,023	289,051	202,610	112,597	18,902	0
Total benefits	(3,793,243)	(3,910,569)	(4,029,650)	(4,150,482)	(4,273,058)	(4,397,370)	(4,523,407)	(4,651,160)	(4,780,614)	(4,911,755)	(5,044,565)	(5,179,056)	(5,315,187)	(5,452,924)	(5,554,558)	(5,606,037)	(5,655,478)	(5,702,743)	(5,747,686)	(5,790,155)	(5,908,582)
Discounted Benefits (in 2020$)	(3,793,243)	(3,815,189)	(3,835,479)	(3,854,135)	(3,871,180)	(3,886,634)	(3,900,520)	(3,912,859)	(3,923,673)	(3,932,981)	(3,940,806)	(3,947,191)	(3,952,138)	(3,955,662)	(3,931,112)	(3,870,775)	(3,809,671)	(3,747,814)	(3,685,220)	(3,621,903)	(3,605,836)
Annual Running Costs:																					
Engine O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
SCR O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
Biogas/GCS Upgrading O&M	207,470	214,246	221,211	228,368	235,723	243,281	251,046	259,025	267,223	275,645	284,298	293,187	302,319	311,698	316,398	314,589	312,581	310,366	307,939	305,290	312,700
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	186,835	190,573	194,385	198,274	202,241	206,287	210,413	214,623	218,917	223,296	227,763	232,320	236,967	241,708	246,543	251,476	256,507	261,638	266,872	272,211	277,657
Natural Gas Purchased - Engine	195,775	201,567	207,512	213,614	219,878	226,306	232,904	239,675	246,624	253,755	261,072	268,581	276,285	284,191	308,997	356,921	406,639	458,204	511,667	567,087	589,703
Dig 1 & 5 O&M	600,000	612,000	624,240	636,725	649,459	662,448	675,697	689,211	702,996	717,056	731,397	746,025	760,945	776,164	791,687	807,521	823,671	840,145	856,948	874,087	891,568
Dewatering Polymer	7,456	7,605	7,757	7,913	8,071	8,232	8,397	8,565	8,736	8,911	9,089	9,271	9,456	9,645	9,081	7,480	5,812	4,074	2,264	380	0
Dewatering Power	10,374	10,582	10,793	11,009	11,229	11,454	11,683	11,917	12,155	12,398	12,646	12,899	13,157	13,420	12,634	10,407	8,086	5,668	3,150	529	0
Class B Hauling	323,901	330,379	336,987	343,726	350,601	357,613	364,765	372,061	379,502	387,092	394,834	402,730	410,785	419,001	394,466	324,934	252,464	176,965	98,345	16,509	0
Total running costs	2,011,812	2,058,388	2,106,023	2,154,740	2,204,563	2,255,517	2,307,627	2,360,919	2,415,421	2,471,157	2,528,158	2,586,451	2,646,065	2,707,028	2,746,407	2,755,684	2,764,234	2,772,023	2,779,018	2,785,185	2,838,377
Discounted Running Costs (in 2020$)	2,011,812	2,008,184	2,004,543	2,000,890	1,997,225	1,993,548	1,989,859	1,986,159	1,982,448	1,978,726	1,974,993	1,971,250	1,967,497	1,963,733	1,943,707	1,902,705	1,862,057	1,821,760	1,781,812	1,742,210	1,732,179
		0																			
Net escalated benefit/(cost)	26,664,416	(1,852,181)	(1,923,627)	(1,995,743)	(2,068,495)	(2,141,853)	(2,215,781)	(2,290,241)	(2,365,193)	(2,440,597)	(2,516,407)	(2,592,605)	(2,669,122)	(2,745,896)	(2,808,151)	(2,850,353)	(2,891,245)	(2,930,720)	(2,968,667)	(3,004,971)	(3,070,205)
Life cycle cost analysis																					
PVs in 2020	26,664,416	(1,807,006)	(1,830,936)	(1,853,245)	(1,873,955)	(1,893,086)	(1,910,661)	(1,926,700)	(1,941,224)	(1,954,255)	(1,965,813)	(1,975,941)	(1,984,641)	(1,991,929)	(1,987,405)	(1,968,071)	(1,947,615)	(1,926,055)	(1,903,408)	(1,879,693)	(1,873,657)
Cumulative Benefits Payback	26,664,416	24,857,410	23,026,474	21,173,229	19,299,274	17,406,188	15,495,527	13,568,827	11,627,603	9,673,348	7,707,534	5,731,594	3,746,952	1,755,024	(232,381)	(2,200,452)	(4,148,067)	(6,074,121)	(7,977,530)	(9,857,222)	
NPV as of 2020	(11,730,879)																				

ALTERNATIVE 2.5

Risk adjustments (+/- percent):			
Year of analysis	2020	Benefits	0%
Escalation rate	2.00%	Capital costs	0%
Discount rate	2.50%	Running costs	0%

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

	Year																				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Expressed in 2020 dollars, unescalated -- dollars																					
Capital Outlays																					
BUS 1200 scfm + Interconnection	21,200,000																				
Oxicat	1,000,000																				
HSW Receiving Facility	3,000,000																				
Dig 1&3 Improvements	5,500,000																				
Total capital outlays	30,700,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,372,328	2,396,794	2,420,224	2,442,619	2,463,979	2,484,303	2,503,592	2,521,846	2,539,065	2,555,248	2,570,417	2,584,550	2,597,648	2,609,710	2,620,736	2,630,726	2,639,681	2,647,599	2,654,482	2,660,329
LCFS	747,102	755,220	763,010	770,469	777,599	784,399	790,870	797,011	802,823	808,305	813,457	818,280	822,780	826,950	830,790	834,301	837,482	840,333	842,854	845,046	846,908
Natural Gas Sale	328,475	335,503	342,531	349,559	356,587	363,615	370,643	377,671	384,699	391,727	398,755	405,787	412,818	419,850	426,881	433,913	440,944	447,975	455,007	462,038	469,070
HSW Tipping Fee	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	342,280	276,419	210,558	144,697	78,836	12,975	0
Total benefits	(3,793,243)	(3,833,891)	(3,873,174)	(3,911,092)	(3,947,645)	(3,982,833)	(4,016,656)	(4,049,115)	(4,080,208)	(4,109,937)	(4,138,300)	(4,165,324)	(4,190,988)	(4,215,288)	(4,209,661)	(4,165,368)	(4,119,710)	(4,072,685)	(4,024,296)	(3,974,541)	(3,976,306)
Annual Running Costs:																					
Engine O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
SCR O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
Biogas/GCS Upgrading O&M	207,470	210,046	212,621	215,196	217,771	220,347	222,922	225,497	228,073	230,648	233,223	235,800	238,376	240,953	239,790	233,744	227,698	221,652	215,606	209,560	210,438
Natural Gas Purchased - Dryer	186,835	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844	186,845	186,846	186,847	186,848	186,849	186,850	186,851	186,852	186,853	186,854	186,855
Natural Gas Purchased - Engine	195,775	197,614	199,454	201,294	203,133	204,973	206,812	208,652	210,491	212,331	214,170	216,010	217,849	219,689	234,181	265,198	296,215	327,232	358,249	389,266	396,853
HSW Facility O&M	100,000	100,001	100,002	100,003	100,004	100,005	100,006	100,007	100,008	100,009	100,010	100,011	100,012	100,013	100,014	100,015	100,016	100,017	100,018	100,019	100,020
Dig 1 & 5 O&M	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Dewatering Polymer	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	6,882	5,558	4,233	2,909	1,585	261	0
Dewatering Power	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	9,575	7,733	5,890	4,048	2,205	363	0
Class B Hauling	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	298,956	241,431	183,906	126,382	68,857	11,332	0
Total running costs	2,111,812	2,118,029	2,124,245	2,130,462	2,136,679	2,142,896	2,149,113	2,155,329	2,161,546	2,167,763	2,173,980	2,180,198	2,186,416	2,192,634	2,181,447	2,147,529	2,113,610	2,079,692	2,045,774	2,011,855	2,010,166
Net Benefit/(cost)	29,018,568	(1,715,863)	(1,748,929)	(1,780,630)	(1,810,966)	(1,839,937)	(1,867,544)	(1,893,785)	(1,918,662)	(1,942,174)	(1,964,320)	(1,985,126)	(2,004,572)	(2,022,654)	(2,028,214)	(2,017,839)	(2,006,099)	(1,992,993)	(1,978,522)	(1,962,685)	(1,966,140)
Expressed in escalated dollars with sensitivity adjustments																					
Capital Outlays																					
BUS 1200 scfm + Interconnection	21,200,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oxicat	1,000,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dig 1&3 Improvements	5,500,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	30,700,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,419,774	2,493,624	2,568,361	2,643,969	2,720,432	2,797,729	2,875,841	2,954,745	3,034,417	3,114,833	3,195,990	3,277,835	3,360,335	3,443,457	3,527,166	3,611,423	3,696,190	3,781,424	3,867,079	3,953,109
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LCFS	747,102	770,325	793,835	817,628	841,698	866,040	890,648	915,515	940,635	965,999	991,599	1,017,428	1,043,483	1,069,748	1,096,210	1,122,859	1,149,683	1,176,669	1,203,803	1,231,072	1,258,460
Natural Gas Sale	328,475	342,213	356,369	370,955	385,981	401,460	417,404	433,826	450,737	468,150	486,081	504,545	523,553	543,120	563,261	583,989	605,322	627,274	649,862	673,103	697,013
HSW Tipping Fee	370,840	378,257	385,822	393,538	401,409	409,437	417,626	425,979	434,498	443,188	452,052	461,093	470,315	479,721	451,631	372,023	289,051	202,610	112,597	18,902	0
Total benefits	(3,793,243)	(3,910,569)	(4,029,650)	(4,150,482)	(4,273,058)	(4,397,370)	(4,523,407)	(4,651,160)	(4,780,614)	(4,911,755)	(5,044,565)	(5,179,056)	(5,315,187)	(5,452,924)	(5,554,558)	(5,606,037)	(5,655,478)	(5,702,743)	(5,747,686)	(5,790,155)	(5,908,582)
Discounted Benefits (in 2020$)	(3,793,243)	(3,815,189)	(3,835,479)	(3,854,135)	(3,871,180)	(3,886,634)	(3,900,520)	(3,912,859)	(3,923,673)	(3,932,981)	(3,940,806)	(3,947,191)	(3,952,138)	(3,955,662)	(3,931,112)	(3,870,775)	(3,809,671)	(3,747,814)	(3,685,220)	(3,621,903)	(3,605,836)
Annual Running Costs:																					
Engine O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
SCR O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
Biogas/GCS Upgrading O&M	207,470	214,246	221,211	228,368	235,723	243,281	251,046	259,025	267,223	275,645	284,298	293,187	302,319	311,698	316,398	314,589	312,581	310,366	307,939	305,290	312,700
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	186,835	190,573	194,385	198,274	202,241	206,287	210,413	214,623	218,917	223,296	227,763	232,320	236,967	241,708	246,543	251,476	256,507	261,638	266,872	272,211	277,657
Natural Gas Purchased - Engine	195,775	201,567	207,512	213,614	219,878	226,306	232,904	239,675	246,624	253,755	261,072	268,581	276,285	284,191	308,997	356,921	406,639	458,204	511,667	567,087	589,703
Dig 1 & 5 O&M	600,000	612,000	624,240	636,725	649,459	662,448	675,697	689,211	702,996	717,056	731,397	746,025	760,945	776,164	791,687	807,521	823,671	840,145	856,948	874,087	891,568
Dewatering Polymer	7,456	7,605	7,757	7,913	8,071	8,232	8,397	8,565	8,736	8,911	9,089	9,271	9,456	9,645	9,081	7,480	5,812	4,074	2,264	380	0
Dewatering Power	10,374	10,582	10,793	11,009	11,229	11,454	11,683	11,917	12,155	12,398	12,646	12,899	13,157	13,420	12,634	10,407	8,086	5,668	3,150	529	0
Class B Hauling	323,901	330,379	336,987	343,726	350,601	357,613	364,765	372,061	379,502	387,092	394,834	402,730	410,785	419,001	394,466	324,934	252,464	176,965	98,345	16,509	0
Total running costs	2,011,812	2,058,388	2,106,023	2,154,740	2,204,563	2,255,517	2,307,627	2,360,919	2,415,421	2,471,157	2,528,158	2,586,451	2,646,065	2,707,028	2,746,407	2,755,684	2,764,234	2,772,023	2,779,018	2,785,185	2,838,377
Discounted Running Costs (in 2020$)	2,011,812	2,008,184	2,004,543	2,000,890	1,997,225	1,993,548	1,989,859	1,986,159	1,982,448	1,978,726	1,974,993	1,971,250	1,967,497	1,963,733	1,943,707	1,902,705	1,862,057	1,821,760	1,781,812	1,742,210	1,732,179
		0																			
Net escalated benefit/(cost)	28,918,568	(1,852,181)	(1,923,627)	(1,995,743)	(2,068,495)	(2,141,853)	(2,215,781)	(2,290,241)	(2,365,193)	(2,440,597)	(2,516,407)	(2,592,605)	(2,669,122)	(2,745,896)	(2,808,151)	(2,850,353)	(2,891,245)	(2,930,720)	(2,968,667)	(3,004,971)	(3,070,205)
Life cycle cost analysis																					
PVs in 2020	28,918,568	(1,807,006)	(1,830,936)	(1,853,245)	(1,873,955)	(1,893,086)	(1,910,661)	(1,926,700)	(1,941,224)	(1,954,255)	(1,965,813)	(1,975,941)	(1,984,641)	(1,991,929)	(1,987,405)	(1,968,071)	(1,947,615)	(1,926,055)	(1,903,408)	(1,879,693)	(1,873,657)
Cumulative Benefits Payback	28,918,568	27,111,563	25,280,626	23,427,381	21,553,426	19,660,340	17,749,680	15,822,980	13,881,755	11,927,500	9,961,687	7,985,746	6,001,105	4,009,176	2,021,771	53,701	(1,893,914)	(3,819,969)	(5,723,377)	(7,603,070)	
NPV as of 2020	(9,476,726)																				

ALTERNATIVE 2.75

		Risk adjustments (+/- percent):	
Year of analysis	2020	Benefits	0%
Escalation rate	2.00%	Capital costs	0%
Discount rate	2.50%	Running costs	0%

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

	Year																				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Expressed in 2020 dollars, unescalated -- dollars																					
Capital Outlays																					
BUS 1200 scfm + Interconnection	21,200,000																				
Oxicat + SCR	4,900,000																				
HSW Receiving Facility	3,000,000																				
Dig 1&3 Improvements	5,500,000																				
Total capital outlays	34,600,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,372,328	2,396,794	2,420,224	2,442,619	2,463,979	2,484,303	2,503,592	2,521,846	2,539,065	2,555,248	2,570,417	2,584,550	2,597,648	2,609,710	2,620,736	2,630,726	2,639,681	2,647,599	2,654,482	2,660,329
LCFS	747,102	755,220	763,010	770,469	777,599	784,399	790,870	797,011	802,823	808,305	813,457	818,280	822,780	826,950	830,790	834,301	837,482	840,333	842,854	845,046	846,908
Natural Gas Sale	328,475	335,503	342,531	349,559	356,587	363,615	370,643	377,671	384,699	391,727	398,755	405,787	412,818	419,850	426,881	433,913	440,944	447,975	455,007	462,038	469,070
HSW Tipping Fee	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	342,280	276,419	210,558	144,697	78,836	12,975	0
Total benefits	(3,793,243)	(3,833,891)	(3,873,174)	(3,911,092)	(3,947,645)	(3,982,833)	(4,016,656)	(4,049,115)	(4,080,208)	(4,109,937)	(4,138,300)	(4,165,324)	(4,190,988)	(4,215,288)	(4,209,661)	(4,165,368)	(4,119,710)	(4,072,685)	(4,024,296)	(3,974,541)	(3,976,306)
Annual Running Costs:																					
Engine O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
SCR O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
Biogas/GCS Upgrading O&M	207,470	210,046	212,621	215,196	217,771	220,347	222,922	225,497	228,073	230,648	233,223	235,800	238,376	240,953	239,790	233,744	227,698	221,652	215,606	209,560	210,438
Natural Gas Purchased - Dryer	186,835	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844	186,845	186,846	186,847	186,848	186,849	186,850	186,851	186,852	186,853	186,854	186,855
Natural Gas Purchased - Engine	195,775	197,614	199,454	201,294	203,133	204,973	206,812	208,652	210,491	212,331	214,170	216,010	217,849	219,689	234,181	265,198	296,215	327,232	358,249	389,266	396,853
HSW Facility O&M	100,000	100,001	100,002	100,003	100,004	100,005	100,006	100,007	100,008	100,009	100,010	100,011	100,012	100,013	100,014	100,015	100,016	100,017	100,018	100,019	100,020
Dig 1 & 5 O&M	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Dewatering Polymer	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	6,882	5,558	4,233	2,909	1,585	261	0
Dewatering Power	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	9,575	7,733	5,890	4,048	2,205	363	0
Class B Hauling	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	298,956	241,431	183,906	126,382	68,857	11,332	0
Total running costs	2,111,812	2,118,029	2,124,245	2,130,462	2,136,679	2,142,896	2,149,113	2,155,329	2,161,546	2,167,763	2,173,980	2,180,198	2,186,416	2,192,634	2,181,447	2,147,529	2,113,610	2,079,692	2,045,774	2,011,855	2,010,166
Net Benefit/(cost)	32,918,568	(1,715,863)	(1,748,929)	(1,780,630)	(1,810,966)	(1,839,937)	(1,867,544)	(1,893,785)	(1,918,662)	(1,942,174)	(1,964,320)	(1,985,126)	(2,004,572)	(2,022,654)	(2,028,214)	(2,017,839)	(2,006,099)	(1,992,993)	(1,978,522)	(1,962,685)	(1,966,140)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Expressed in escalated dollars with sensitivity adjustments																					
Capital Outlays																					
BUS 1200 scfm + Interconnection	21,200,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oxicat + SCR	4,900,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dig 1&3 Improvements	5,500,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	34,600,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,419,774	2,493,624	2,568,361	2,643,969	2,720,432	2,797,729	2,875,841	2,954,745	3,034,417	3,114,833	3,195,990	3,277,835	3,360,335	3,443,457	3,527,166	3,611,423	3,696,190	3,781,424	3,867,079	3,953,109
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LCFS	747,102	770,325	793,835	817,628	841,698	866,040	890,648	915,515	940,635	965,999	991,599	1,017,428	1,043,483	1,069,748	1,096,210	1,122,859	1,149,683	1,176,669	1,203,803	1,231,072	1,258,460
Natural Gas Sale	328,475	342,213	356,369	370,955	385,981	401,460	417,404	433,826	450,737	468,150	486,081	504,545	523,553	543,120	563,261	583,989	605,322	627,274	649,862	673,103	697,013
HSW Tipping Fee	370,840	378,257	385,822	393,538	401,409	409,437	417,626	425,979	434,498	443,188	452,052	461,093	470,315	479,721	451,631	372,023	289,051	202,610	112,597	18,902	0
Total benefits	(3,793,243)	(3,910,569)	(4,029,650)	(4,150,482)	(4,273,058)	(4,397,370)	(4,523,407)	(4,651,160)	(4,780,614)	(4,911,755)	(5,044,565)	(5,179,056)	(5,315,187)	(5,452,924)	(5,554,558)	(5,606,037)	(5,655,478)	(5,702,743)	(5,747,686)	(5,790,155)	(5,908,582)
Discounted Benefits (in 2020$)	(3,793,243)	(3,815,189)	(3,835,479)	(3,854,135)	(3,871,180)	(3,886,634)	(3,900,520)	(3,912,859)	(3,923,673)	(3,932,981)	(3,940,806)	(3,947,191)	(3,952,138)	(3,955,662)	(3,931,112)	(3,870,775)	(3,809,671)	(3,747,814)	(3,685,220)	(3,621,903)	(3,605,836)
Annual Running Costs:																					
Engine O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
SCR O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
Biogas/GCS Upgrading O&M	207,470	214,246	221,211	228,368	235,723	243,281	251,046	259,025	267,223	275,645	284,298	293,187	302,319	311,698	316,398	314,589	312,581	310,366	307,939	305,290	312,700
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	186,835	190,573	194,385	198,274	202,241	206,287	210,413	214,623	218,917	223,296	227,763	232,320	236,967	241,708	246,543	251,476	256,507	261,638	266,872	272,211	277,657
Natural Gas Purchased - Engine	195,775	201,567	207,512	213,614	219,878	226,306	232,904	239,675	246,624	253,755	261,072	268,581	276,285	284,191	308,997	356,921	406,639	458,204	511,667	567,087	589,703
Dig 1 & 5 O&M	600,000	612,000	624,240	636,725	649,459	662,448	675,697	689,211	702,996	717,056	731,397	746,025	760,945	776,164	791,687	807,521	823,671	840,145	856,948	874,087	891,568
Dewatering Polymer	7,456	7,605	7,757	7,913	8,071	8,232	8,397	8,565	8,736	8,911	9,089	9,271	9,456	9,645	9,081	7,480	5,812	4,074	2,264	380	0
Dewatering Power	10,374	10,582	10,793	11,009	11,229	11,454	11,683	11,917	12,155	12,398	12,646	12,899	13,157	13,420	12,634	10,407	8,086	5,668	3,150	529	0
Class B Hauling	323,901	330,379	336,987	343,726	350,601	357,613	364,765	372,061	379,502	387,092	394,834	402,730	410,785	419,001	394,466	324,934	252,464	176,965	98,345	16,509	0
Total running costs	2,011,812	2,058,388	2,106,023	2,154,740	2,204,563	2,255,517	2,307,627	2,360,919	2,415,421	2,471,157	2,528,158	2,586,451	2,646,065	2,707,028	2,746,407	2,755,684	2,764,234	2,772,023	2,779,018	2,785,185	2,838,377
Discounted Running Costs (in 2020$)	2,011,812	2,008,184	2,004,543	2,000,890	1,997,225	1,993,548	1,989,859	1,986,159	1,982,448	1,978,726	1,974,993	1,971,250	1,967,497	1,963,733	1,943,707	1,902,705	1,862,057	1,821,760	1,781,812	1,742,210	1,732,179
		0																			
Net escalated benefit/(cost)	32,818,568	(1,852,181)	(1,923,627)	(1,995,743)	(2,068,495)	(2,141,853)	(2,215,781)	(2,290,241)	(2,365,193)	(2,440,597)	(2,516,407)	(2,592,605)	(2,669,122)	(2,745,896)	(2,808,151)	(2,850,353)	(2,891,245)	(2,930,720)	(2,968,667)	(3,004,971)	(3,070,205)
Life cycle cost analysis																					
PVs in 2020	32,818,568	(1,807,006)	(1,830,936)	(1,853,245)	(1,873,955)	(1,893,086)	(1,910,661)	(1,926,700)	(1,941,224)	(1,954,255)	(1,965,813)	(1,975,941)	(1,984,641)	(1,991,929)	(1,987,405)	(1,968,071)	(1,947,615)	(1,926,055)	(1,903,408)	(1,879,693)	(1,873,657)
Cumulative Benefits Payback	32,818,568	31,011,563	29,180,626	27,327,381	25,453,426	23,560,340	21,649,680	19,722,980	17,781,755	15,827,500	13,861,687	11,885,746	9,901,105	7,909,176	5,921,771	3,953,701	2,006,086	80,031	(1,823,377)	(3,703,070)	
NPV as of 2020	(5,576,726)																				

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		Risk adjustments (+/- percent):		
Year of analysis	**2020**		**Benefits**	**0%**
Escalation rate	**2.00%**		**Capital costs**	**0%**
Discount rate	**2.50%**		**Running costs**	**0%**

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Expressed in 2020 dollars, unescalated -- dollars											
Capital Outlays											
BUS + Interconnection	15,300,000										
Oxicat + GCS	5,300,000										
HSW Receiving Facility	3,000,000										
Dig 1&3 Improvements	5,500,000										
Total capital outlays	**29,100,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:											
D3 RINs	2,346,827	2,372,328	2,396,794	2,420,224	2,442,619	2,463,979	2,484,303	2,503,592	2,521,846	2,539,065	2,555,248
LCFS	747,102	755,220	763,010	770,469	777,599	784,399	790,870	797,011	802,823	808,305	813,457
Natural Gas Sale	328,475	335,503	342,531	349,559	356,587	363,615	370,643	377,671	384,699	391,727	398,755
HSW Tipping Fee	817,600	817,600	821,250	825,484	829,718	833,952	838,186	842,420	846,654	850,888	855,122
Total benefits	**(4,240,003)**	**(4,280,651)**	**(4,323,584)**	**(4,365,736)**	**(4,406,523)**	**(4,445,945)**	**(4,484,002)**	**(4,520,695)**	**(4,556,022)**	**(4,589,985)**	**(4,622,582)**
Annual Running Costs:											
Engine O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000
	0	0	0	0	0	0	0	0	0	0	0
Biogas Upgrading/GCS O&M	265,960	268,535	271,588	274,718	277,848	280,977	284,107	287,236	290,366	293,496	296,625
Natural Gas Purchased - Dryer	186,835	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844	186,845
Natural Gas Purchased - Engine											
HSW Facility O&M	150,000	150,001	150,002	150,003	150,004	150,005	150,006	150,007	150,008	150,009	150,010
Dig 1 & 5 O&M	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Dewatering Polymer	16,439	16,439	16,512	16,597	16,682	16,767	16,853	16,938	17,023	17,108	17,193
Dewatering Power	22,872	22,872	22,974	23,093	23,211	23,330	23,448	23,567	23,685	23,804	23,922
Class B Hauling	714,113	714,113	717,301	720,999	724,697	728,395	732,093	735,791	739,489	743,187	746,885
Total running costs	**2,196,219**	**2,199,696**	**2,207,015**	**2,214,948**	**2,222,881**	**2,230,815**	**2,238,748**	**2,246,681**	**2,254,614**	**2,262,548**	**2,270,481**
Net Benefit/(cost)	**27,056,215**	**(2,080,955)**	**(2,116,569)**	**(2,150,788)**	**(2,183,642)**	**(2,215,131)**	**(2,245,255)**	**(2,274,014)**	**(2,301,408)**	**(2,327,437)**	**(2,352,101)**
Expressed in escalated dollars with sensitivity adjustments											
Capital Outlays											
BUS + Interconnection	15,300,000	0	0	0	0	0	0	0	0	0	0
Oxicat + GCS	5,300,000	0	0	0	0	0	0	0	0	0	0
Dig 1&3 Improvements	5,500,000	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**29,100,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:											
D3 RINs	2,346,827	2,419,774	2,493,624	2,568,361	2,643,969	2,720,432	2,797,729	2,875,841	2,954,745	3,034,417	3,114,833
0	0	0	0	0	0	0	0	0	0	0	0
LCFS	747,102	770,325	793,835	817,628	841,698	866,040	890,648	915,515	940,635	965,999	991,599
Natural Gas Sale	328,475	342,213	356,369	370,955	385,981	401,460	417,404	433,826	450,737	468,150	486,081
HSW Tipping Fee	817,600	833,952	854,429	876,010	898,113	920,750	943,934	967,676	991,990	1,016,890	1,042,389
Total benefits	**(4,240,003)**	**(4,366,264)**	**(4,498,257)**	**(4,632,954)**	**(4,769,762)**	**(4,908,683)**	**(5,049,715)**	**(5,192,857)**	**(5,338,106)**	**(5,485,456)**	**(5,634,902)**
Discounted Benefits (in 2020$)	**(4,240,003)**	**(4,259,770)**	**(4,281,506)**	**(4,302,158)**	**(4,321,169)**	**(4,338,560)**	**(4,354,353)**	**(4,368,570)**	**(4,381,232)**	**(4,392,361)**	**(4,401,976)**
Annual Running Costs:											
Engine O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530
0	0	0	0	0	0	0	0	0	0	0	0
Biogas Upgrading/GCS O&M	265,960	273,906	282,561	291,533	300,751	310,221	319,950	329,944	340,210	350,754	361,584
0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	186,835	190,573	194,385	198,274	202,241	206,287	210,413	214,623	218,917	223,296	227,763
Natural Gas Purchased - Engine	0	0	0	0	0	0	0	0	0	0	0
Dig 1 & 5 O&M	600,000	612,000	624,240	636,725	649,459	662,448	675,697	689,211	702,996	717,056	731,397
Dewatering Polymer	16,439	16,767	17,179	17,613	18,058	18,513	18,979	19,456	19,945	20,446	20,958
Dewatering Power	22,872	23,330	23,903	24,506	25,125	25,758	26,407	27,071	27,751	28,447	29,161
Class B Hauling	714,113	728,395	746,280	765,130	784,435	804,207	824,456	845,193	866,429	888,178	910,449
Total running costs	**2,046,219**	**2,090,689**	**2,140,116**	**2,191,336**	**2,243,749**	**2,297,382**	**2,352,262**	**2,408,419**	**2,465,882**	**2,524,679**	**2,584,842**
Discounted Running Costs (in 2020$)	**2,046,219**	**2,039,697**	**2,036,993**	**2,034,873**	**2,032,726**	**2,030,551**	**2,028,349**	**2,026,120**	**2,023,864**	**2,021,582**	**2,019,274**
		0									
Net escalated benefit/(cost)	**26,906,215**	**(2,275,575)**	**(2,358,141)**	**(2,441,618)**	**(2,526,013)**	**(2,611,301)**	**(2,697,453)**	**(2,784,438)**	**(2,872,224)**	**(2,960,777)**	**(3,050,060)**
Life cycle cost analysis											
PVs in 2020	26,906,215	(2,220,073)	(2,244,512)	(2,267,285)	(2,288,443)	(2,308,010)	(2,326,005)	(2,342,451)	(2,357,368)	(2,370,778)	(2,382,702)
Cumulative Benefits Payback	**26,906,215**	**24,686,142**	**22,441,630**	**20,174,345**	**17,885,901**	**15,577,892**	**13,251,887**	**10,909,436**	**8,552,068**	**6,181,290**	**3,798,588**
NPV as of 2020	**(20,373,475)**										

Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Expressed in 2020 dollars, unescalated -- dollars										
Capital Outlays										
BUS + Interconnection										
Oxicat + GCS										
HSW Receiving Facility										
Dig 1&3 Improvements										
Total capital outlays	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:										
D3 RINs	2,570,417	2,584,550	2,597,648	2,609,710	2,620,736	2,630,726	2,639,681	2,647,599	2,654,482	2,660,329
LCFS	818,280	822,780	826,950	830,790	834,301	837,482	840,333	842,854	845,046	846,908
Natural Gas Sale	405,787	412,818	419,850	426,881	433,913	440,944	447,975	455,007	462,038	469,070
HSW Tipping Fee	858,480	862,860	867,094	871,036	874,978	879,212	883,446	887,680	892,060	896,440
Total benefits	**(4,652,964)**	**(4,683,008)**	**(4,711,542)**	**(4,738,417)**	**(4,763,927)**	**(4,788,364)**	**(4,811,435)**	**(4,833,140)**	**(4,853,626)**	**(4,872,746)**
Annual Running Costs:										
Engine O&M	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
	0	0	0	0	0	0	0	0	0	0
Biogas Upgrading/GCS O&M	299,641	302,791	305,922	309,015	312,107	315,238	318,369	321,500	324,650	327,800
Natural Gas Purchased - Dryer	186,846	186,847	186,848	186,849	186,850	186,851	186,852	186,853	186,854	186,855
Natural Gas Purchased - Engine										
HSW Facility O&M	150,011	150,012	150,013	150,014	150,015	150,016	150,017	150,018	150,019	150,020
Dig 1 & 5 O&M	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Dewatering Polymer	17,261	17,349	17,434	17,513	17,592	17,677	17,763	17,848	17,936	18,024
Dewatering Power	24,016	24,139	24,257	24,367	24,478	24,596	24,714	24,833	24,955	25,078
Class B Hauling	749,818	753,644	757,342	760,785	764,228	767,926	771,624	775,322	779,148	782,974
Total running costs	**2,277,493**	**2,285,581**	**2,293,516**	**2,301,143**	**2,308,770**	**2,316,705**	**2,324,639**	**2,332,574**	**2,340,662**	**2,348,750**
Net Benefit/(cost)	**(2,375,470)**	**(2,397,427)**	**(2,418,026)**	**(2,437,274)**	**(2,455,157)**	**(2,471,659)**	**(2,486,795)**	**(2,500,566)**	**(2,512,964)**	**(2,523,996)**
Expressed in escalated dollars with sensitivity adjustments										
Capital Outlays										
BUS + Interconnection	0	0	0	0	0	0	0	0	0	0
Oxicat + GCS	0	0	0	0	0	0	0	0	0	0
Dig 1&3 Improvements	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:										
D3 RINs	3,195,990	3,277,835	3,360,335	3,443,457	3,527,166	3,611,423	3,696,190	3,781,424	3,867,079	3,953,109
0	0	0	0	0	0	0	0	0	0	0
LCFS	1,017,428	1,043,483	1,069,748	1,096,210	1,122,859	1,149,683	1,176,669	1,203,803	1,231,072	1,258,460
Natural Gas Sale	504,545	523,553	543,120	563,261	583,989	605,322	627,274	649,862	673,103	697,013
HSW Tipping Fee	1,067,412	1,094,315	1,121,679	1,149,314	1,177,605	1,206,970	1,237,038	1,267,826	1,299,563	1,332,063
Total benefits	**(5,785,375)**	**(5,939,187)**	**(6,094,881)**	**(6,252,241)**	**(6,411,619)**	**(6,573,397)**	**(6,737,170)**	**(6,902,914)**	**(7,070,817)**	**(7,240,645)**
Discounted Benefits (in 2020$)	**(4,409,294)**	**(4,416,117)**	**(4,421,351)**	**(4,424,881)**	**(4,427,002)**	**(4,428,004)**	**(4,427,635)**	**(4,425,913)**	**(4,422,992)**	**(4,418,755)**
Annual Running Costs:										
Engine O&M	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
0	0	0	0	0	0	0	0	0	0	0
Biogas Upgrading/GCS O&M	372,566	384,012	395,743	407,738	420,055	432,754	445,793	459,181	472,953	487,093
0	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	232,320	236,967	241,708	246,543	251,476	256,507	261,638	266,872	272,211	277,657
Natural Gas Purchased - Engine	0	0	0	0	0	0	0	0	0	0
Dig 1 & 5 O&M	746,025	760,945	776,164	791,687	807,521	823,671	840,145	856,948	874,087	891,568
Dewatering Polymer	21,461	22,002	22,553	23,108	23,677	24,267	24,872	25,491	26,129	26,783
Dewatering Power	29,861	30,613	31,379	32,152	32,944	33,765	34,606	35,467	36,355	37,264
Class B Hauling	932,305	955,803	979,703	1,003,840	1,028,550	1,054,198	1,080,460	1,107,351	1,135,071	1,163,457
Total running costs	**2,645,257**	**2,708,418**	**2,772,850**	**2,838,369**	**2,905,400**	**2,974,399**	**3,044,996**	**3,117,227**	**3,191,353**	**3,267,197**
Discounted Running Costs (in 2020$)	**2,016,069**	**2,013,860**	**2,011,482**	**2,008,791**	**2,006,079**	**2,003,630**	**2,001,156**	**1,998,660**	**1,996,280**	**1,993,876**
Net escalated benefit/(cost)	**(3,140,118)**	**(3,230,768)**	**(3,322,032)**	**(3,413,872)**	**(3,506,218)**	**(3,598,998)**	**(3,692,174)**	**(3,785,687)**	**(3,879,463)**	**(3,973,447)**
Life cycle cost analysis										
PVs in 2020	(2,393,225)	(2,402,257)	(2,409,870)	(2,416,090)	(2,420,923)	(2,424,375)	(2,426,479)	(2,427,254)	(2,426,712)	(2,424,879)
Cumulative Benefits Payback	**1,405,363**	**(996,894)**								

ALTERNATIVE 4

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

Year of analysis	2020	**Risk adjustments (+/- percent): Benefits**	0%
Escalation rate	2.00%	**Capital costs**	0%
Discount rate	2.50%	**Running costs**	0%

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Expressed in 2020 dollars, unescalated -- dollars																					
Capital Outlays																					
BUS + Interconnection	24,000,000																				
SCR	4,000,000																				
HSW Receiving Facility	6,000,000																				
Dig 1&3 Improvements	5,500,000																				
Total capital outlays	39,500,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,372,328	2,396,794	2,420,224	2,442,619	2,463,979	2,484,303	2,503,592	2,521,846	2,539,065	2,555,248	2,570,417	2,584,550	2,597,648	2,609,710	2,620,736	2,630,726	2,639,681	2,647,599	2,654,482	2,660,329
D5 RINs	157,772	156,145	154,519	152,892	151,266	149,639	148,013	146,386	144,760	143,133	141,507	139,880	138,254	136,627	124,604	99,415	74,804	50,772	27,316		0
LCFS	1,287,788	1,290,332	1,292,547	1,294,433	1,295,988	1,297,215	1,298,111	1,298,678	1,298,916	1,298,824	1,298,402	1,297,657	1,296,583	1,295,172	1,273,585	1,226,510	1,180,215	1,134,694	1,089,947	1,045,974	1,036,888
Natural Gas Sale	566,196	573,224	580,252	587,280	594,308	601,336	608,364	615,392	622,420	629,448	636,476	643,508	650,539	657,571	654,398	637,898	621,398	604,899	588,399	571,899	574,295
HSW Tipping Fee	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	370,840	342,280	276,419	210,558	144,697	78,836	12,975	0
Total benefits	(4,729,422)	(4,762,869)	(4,794,952)	(4,825,669)	(4,855,021)	(4,883,009)	(4,909,631)	(4,934,889)	(4,958,782)	(4,981,310)	(5,002,473)	(5,022,302)	(5,040,767)	(5,057,858)	(5,004,576)	(4,860,978)	(4,717,702)	(4,574,742)	(4,432,097)	(4,285,330)	(4,271,512)
Annual Running Costs:																					
Engine O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
SCR O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
Biogas Upgrading O&M	207,470	210,046	212,621	215,196	217,771	220,347	222,922	225,497	228,073	230,648	233,223	235,800	238,376	240,953	239,790	233,744	227,698	221,652	215,606	209,560	210,438
NC Demand																					
Natural Gas Purchased - Dryer	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835
Natural Gas Purchased - Engine	490,537	492,376	494,216	496,055	497,895	499,734	501,574	503,413	505,253	507,092	508,932	510,771	512,611	514,450	516,290	518,130	519,969	521,809	523,648	525,488	527,327
HSW Facility O&M	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Dig 1 & 5 O&M	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Dewatering Polymer	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	6,882	5,558	4,233	2,909	1,585	261	0
Dewatering Power	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	10,374	9,575	7,733	5,890	4,048	2,205	363	0
Class B Hauling	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	323,901	298,956	241,431	183,906	126,382	68,857	11,332	0
Total running costs	2,406,574	2,412,789	2,419,003	2,425,218	2,431,433	2,437,648	2,443,862	2,450,077	2,456,292	2,462,507	2,468,722	2,474,938	2,481,154	2,487,370	2,463,528	2,400,430	2,337,333	2,274,235	2,211,137	2,148,039	2,140,600
Net Benefit/(cost)	37,177,152	(2,350,081)	(2,375,948)	(2,400,451)	(2,423,588)	(2,445,361)	(2,465,769)	(2,484,812)	(2,502,490)	(2,518,803)	(2,533,751)	(2,547,365)	(2,559,613)	(2,570,489)	(2,541,048)	(2,460,548)	(2,380,369)	(2,300,507)	(2,220,960)	(2,137,290)	(2,130,912)
Expressed in escalated dollars with sensitivity adjustments																					
Capital Outlays																					
BUS + Interconnection	24,000,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCR	4,000,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dig 1&3 Improvements	5,500,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	39,500,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benefits:																					
D3 RINs	2,346,827	2,419,774	2,493,624	2,568,361	2,643,969	2,720,432	2,797,729	2,875,841	2,954,745	3,034,417	3,114,833	3,195,990	3,277,835	3,360,335	3,443,457	3,527,166	3,611,423	3,696,190	3,781,424	3,867,079	3,953,109
D5 RINs	157,772	159,268	160,761	162,251	163,735	165,214	166,687	168,152	169,609	171,058	172,496	173,924	175,339	176,742	164,412	133,800	102,691	71,092	39,014	0	0
LCFS	1,287,788	1,316,139	1,344,766	1,373,662	1,402,820	1,432,230	1,461,884	1,491,773	1,521,887	1,552,215	1,582,745	1,613,474	1,644,381	1,675,444	1,680,469	1,650,721	1,620,183	1,588,846	1,556,713	1,523,786	1,540,761
Natural Gas Sale	566,196	584,688	603,694	623,226	643,298	663,924	685,117	706,892	729,264	752,249	775,861	800,121	825,041	850,638	863,464	858,527	853,047	847,004	840,378	833,149	853,372
HSW Tipping Fee	370,840	378,257	385,822	393,538	401,409	409,437	417,626	425,979	434,498	443,188	452,052	461,093	470,315	479,721	451,631	372,023	289,051	202,610	112,597	18,902	0
Total benefits	(4,729,422)	(4,858,127)	(4,988,668)	(5,121,038)	(5,255,231)	(5,391,236)	(5,529,042)	(5,668,636)	(5,810,003)	(5,953,126)	(6,097,986)	(6,244,602)	(6,392,911)	(6,542,879)	(6,603,432)	(6,542,236)	(6,476,394)	(6,405,743)	(6,330,126)	(6,242,916)	(6,347,242)
Discounted Benefits (in 2020$)	(4,729,422)	(4,739,636)	(4,748,286)	(4,755,393)	(4,760,980)	(4,765,067)	(4,767,676)	(4,768,827)	(4,768,540)	(4,766,837)	(4,763,737)	(4,759,291)	(4,753,487)	(4,746,338)	(4,673,428)	(4,517,189)	(4,362,660)	(4,209,823)	(4,058,661)	(3,905,117)	(3,873,537)
Annual Running Costs:																					
Engine O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
SCR O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
Biogas Upgrading O&M	207,470	214,246	221,211	228,368	235,723	243,281	251,046	259,025	267,223	275,645	284,298	293,187	302,319	311,698	316,398	314,589	312,581	310,366	307,939	305,290	312,700
NC Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	186,835	190,572	194,383	198,271	202,236	206,281	210,407	214,615	218,907	223,285	227,751	232,306	236,952	241,691	246,525	251,455	256,485	261,614	266,847	272,184	277,627
Natural Gas Purchased - Engine	490,537	502,224	514,182	526,418	538,937	551,747	564,854	578,264	591,984	606,022	620,385	635,080	650,115	665,497	681,234	697,334	713,806	730,658	747,898	765,536	783,580
Dig 1 & 5 O&M	600,000	612,000	624,240	636,725	649,459	662,448	675,697	689,211	702,996	717,056	731,397	746,025	760,945	776,164	791,687	807,521	823,671	840,145	856,948	874,087	891,568
Dewatering Polymer	7,456	7,605	7,757	7,913	8,071	8,232	8,397	8,565	8,736	8,911	9,089	9,271	9,456	9,645	9,081	7,480	5,812	4,074	2,264	380	0
Dewatering Power	10,374	10,582	10,793	11,009	11,229	11,454	11,683	11,917	12,155	12,398	12,646	12,899	13,157	13,420	12,634	10,407	8,086	5,668	3,150	529	0
Class B Hauling	323,901	330,379	336,987	343,726	350,601	357,613	364,765	372,061	379,502	387,092	394,834	402,730	410,785	419,001	394,466	324,934	252,464	176,965	98,345	16,509	0
Total running costs	2,306,574	2,359,044	2,412,691	2,467,540	2,523,618	2,580,952	2,639,570	2,699,500	2,760,772	2,823,414	2,887,458	2,952,937	3,019,879	3,088,317	3,118,625	3,096,076	3,071,378	3,044,454	3,015,223	2,983,606	3,032,225
Discounted Running Costs (in 2020$)	2,306,574	2,301,507	2,296,434	2,291,356	2,286,273	2,281,185	2,276,093	2,270,996	2,265,894	2,260,788	2,255,678	2,250,565	2,245,449	2,240,328	2,207,136	2,137,734	2,068,957	2,000,800	1,933,258	1,866,328	1,850,479
		0																			
Net escalated benefit/(cost)	37,077,152	(2,499,082)	(2,575,977)	(2,653,498)	(2,731,613)	(2,810,284)	(2,889,473)	(2,969,136)	(3,049,232)	(3,129,712)	(3,210,528)	(3,291,665)	(3,373,032)	(3,454,562)	(3,484,807)	(3,446,160)	(3,405,016)	(3,361,289)	(3,314,903)	(3,259,310)	(3,315,017)
Life cycle cost analysis																					
PVs in 2020	37,077,152	(2,438,129)	(2,451,852)	(2,464,037)	(2,474,707)	(2,483,882)	(2,491,583)	(2,497,831)	(2,502,646)	(2,506,049)	(2,508,059)	(2,508,726)	(2,508,038)	(2,506,010)	(2,466,293)	(2,379,455)	(2,293,704)	(2,209,023)	(2,125,403)	(2,038,788)	(2,023,059)
Cumulative Benefits Payback	37,077,152	34,639,023	32,187,171	29,723,134	27,248,427	24,764,545	22,272,962	19,775,131	17,272,484	14,766,435	12,258,376	9,749,651	7,241,613	4,735,603	2,269,310	(110,144)	(2,403,848)	(4,612,871)	(6,738,273)	(8,777,062)	(10,800,120)
NPV as of 2020	(10,800,120)																				

ALTERNATIVE 5

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

		Risk adjustments (+/- percent):	
Year of analysis	2020	Benefits	0%
Escalation rate	2.00%	Capital costs	0%
Discount rate	2.50%	Running costs	0%

Year

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Expressed in 2020 dollars, unescalated -- dollars											
Capital Outlays											
BUS + Interconnection	24,000,000										
SCR	4,000,000										
HSW Receiving Facility	6,000,000										
Dig 1&3 Improvements	5,500,000										
Total capital outlays	39,500,000	0	0	0	0	0	0	0	0	0	0
Benefits:											
D3 RINs	2,346,827	2,372,328	2,396,794	2,420,224	2,442,619	2,463,979	2,484,303	2,503,592	2,521,846	2,539,065	2,555,248
D5 RINs	1,006,676	996,298	985,920	975,542	965,164	954,786	944,407	934,029	923,651	913,273	902,895
LCFS	2,909,263	1,290,332	1,292,547	1,294,433	1,295,988	1,297,215	1,298,111	1,298,678	1,298,916	1,298,824	1,298,402
Natural Gas Sale	1,279,100	573,224	580,252	587,280	594,308	601,336	608,364	615,392	622,420	629,448	636,476
HSW Tipping Fee	2,366,173	2,366,173	2,366,173	2,366,173	2,366,173	2,366,173	2,366,173	2,366,173	2,366,173	2,366,173	2,366,173
Total benefits	(9,908,039)	(7,598,355)	(7,621,686)	(7,643,652)	(7,664,252)	(7,683,488)	(7,701,359)	(7,717,866)	(7,733,007)	(7,746,783)	(7,759,194)
Annual Running Costs:											
Engine O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000
SCR O&M	240,000	240,900	241,800	242,700	243,600	244,500	245,400	246,300	247,200	248,100	249,000
Biogas Upgrading O&M	468,699	471,274	473,849	476,424	479,000	481,575	484,150	486,726	489,301	491,876	494,451
NC Demand											
Natural Gas Purchased - Dryer	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835
Natural Gas Purchased - Engine	490,537	492,376	494,216	496,055	497,895	499,734	501,574	503,413	505,253	507,092	508,932
HSW Facility O&M	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Dig 1 & 5 O&M	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Dewatering Polymer	47,574	47,574	47,574	47,574	47,574	47,574	47,574	47,574	47,574	47,574	47,574
Dewatering Power	66,194	66,194	66,194	66,194	66,194	66,194	66,194	66,194	66,194	66,194	66,194
Class B Hauling	2,066,676	2,066,676	2,066,676	2,066,676	2,066,676	2,066,676	2,066,676	2,066,676	2,066,676	2,066,676	2,066,676
Total running costs	4,856,515	4,862,730	4,868,944	4,875,159	4,881,374	4,887,589	4,893,804	4,900,018	4,906,233	4,912,448	4,918,663
Net Benefit/(cost)	34,448,476	(2,735,626)	(2,752,742)	(2,768,492)	(2,782,879)	(2,795,900)	(2,807,556)	(2,817,847)	(2,826,774)	(2,834,335)	(2,840,532)
Expressed in escalated dollars with sensitivity adjustments											
Capital Outlays											
BUS + Interconnection	24,000,000	0	0	0	0	0	0	0	0	0	0
SCR	4,000,000	0	0	0	0	0	0	0	0	0	0
Dig 1&3 Improvements	5,500,000	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	39,500,000	0	0	0	0	0	0	0	0	0	0
Benefits:											
D3 RINs	2,346,827	2,419,774	2,493,624	2,568,361	2,643,969	2,720,432	2,797,729	2,875,841	2,954,745	3,034,417	3,114,833
D5 RINs	1,006,676	1,016,224	1,025,751	1,035,253	1,044,724	1,054,160	1,063,556	1,072,906	1,082,205	1,091,446	1,100,624
LCFS	2,909,263	1,316,139	1,344,766	1,373,662	1,402,820	1,432,230	1,461,884	1,491,773	1,521,887	1,552,215	1,582,745
Natural Gas Sale	1,279,100	584,688	603,694	623,226	643,298	663,924	685,117	706,892	729,264	752,249	775,861
HSW Tipping Fee	2,366,173	2,413,497	2,461,767	2,511,002	2,561,222	2,612,447	2,664,695	2,717,989	2,772,349	2,827,796	2,884,352
Total benefits	(9,908,039)	(7,750,322)	(7,929,602)	(8,111,504)	(8,296,033)	(8,483,192)	(8,672,982)	(8,865,402)	(9,060,450)	(9,258,123)	(9,458,415)
Discounted Benefits (in 2020$)	(9,908,039)	(7,561,290)	(7,547,509)	(7,532,338)	(7,515,797)	(7,497,906)	(7,478,685)	(7,458,154)	(7,436,333)	(7,413,241)	(7,388,898)
Annual Running Costs:											
Engine O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530
SCR O&M	240,000	245,718	251,569	257,555	263,680	269,948	276,360	282,921	289,634	296,502	303,530
Biogas Upgrading O&M	468,699	480,699	492,993	505,585	518,485	531,698	545,232	559,095	573,294	587,838	602,734
NC Demand	0	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	186,835	190,572	194,383	198,271	202,236	206,281	210,407	214,615	218,907	223,285	227,751
Natural Gas Purchased - Engine	490,537	502,224	514,182	526,418	538,937	551,747	564,854	578,264	591,984	606,022	620,385
Dig 1 & 5 O&M	600,000	612,000	624,240	636,725	649,459	662,448	675,697	689,211	702,996	717,056	731,397
Dewatering Polymer	47,574	48,526	49,496	50,486	51,496	52,526	53,577	54,648	55,741	56,856	57,993
Dewatering Power	66,194	67,518	68,868	70,245	71,650	73,083	74,545	76,036	77,556	79,108	80,690
Class B Hauling	2,066,676	2,108,010	2,150,170	2,193,173	2,237,037	2,281,777	2,327,413	2,373,961	2,421,440	2,469,869	2,519,267
Total running costs	4,406,515	4,500,984	4,597,470	4,696,014	4,796,662	4,899,457	5,004,445	5,111,672	5,221,187	5,333,038	5,447,275
Discounted Running Costs (in 2020$)	4,406,515	4,391,204	4,375,938	4,360,716	4,345,539	4,330,406	4,315,317	4,300,272	4,285,272	4,270,315	4,255,402
		0									
Net escalated benefit/(cost)	33,998,476	(3,249,338)	(3,332,132)	(3,415,490)	(3,499,372)	(3,583,736)	(3,668,537)	(3,753,729)	(3,839,263)	(3,925,084)	(4,011,140)
Life cycle cost analysis											
PVs in 2020	33,998,476	(3,170,086)	(3,171,571)	(3,171,622)	(3,170,258)	(3,167,500)	(3,163,368)	(3,157,882)	(3,151,062)	(3,142,926)	(3,133,496)
Cumulative Benefits Payback	33,998,476	30,828,390	27,656,819	24,485,197	21,314,939	18,147,439	14,984,071	11,826,189	8,675,127	5,532,201	2,398,705
NPV as of 2020	(22,472,464)										

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Expressed in 2020 dollars, unescalated -- dollars										
Capital Outlays										
BUS + Interconnection										
SCR										
HSW Receiving Facility										
Dig 1&3 Improvements										
Total capital outlays	0	0	0	0	0	0	0	0	0	0
Benefits:										
D3 RINs	2,570,417	2,584,550	2,597,648	2,609,710	2,620,736	2,630,726	2,639,681	2,647,599	2,654,482	2,660,329
D5 RINs	892,517	882,139	871,761	124,604	99,415	74,804	50,772	27,316	4,439	0
LCFS	1,297,657	1,296,583	1,295,172	1,273,585	1,226,510	1,180,215	1,134,694	1,089,947	1,045,974	1,036,888
Natural Gas Sale	643,508	650,539	657,571	654,398	637,898	621,398	604,899	588,399	571,899	574,295
HSW Tipping Fee	2,366,173	2,366,173	2,366,173	342,280	276,419	210,558	144,697	78,836	12,975	0
Total benefits	(7,770,272)	(7,779,985)	(7,788,325)	(5,004,576)	(4,860,978)	(4,717,702)	(4,574,742)	(4,432,097)	(4,289,768)	(4,271,512)
Annual Running Costs:										
Engine O&M	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
SCR O&M	249,900	250,800	251,700	252,600	253,500	254,400	255,300	256,200	257,100	258,000
Biogas Upgrading O&M	497,028	499,604	502,181	239,790	233,744	227,698	221,652	215,606	209,560	210,438
NC Demand										
Natural Gas Purchased - Dryer	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835	186,835
Natural Gas Purchased - Engine	510,771	512,611	514,450	516,290	518,130	519,969	521,809	523,648	525,488	527,327
HSW Facility O&M	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Dig 1 & 5 O&M	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Dewatering Polymer	47,574	47,574	47,574	6,882	5,558	4,233	2,909	1,585	261	0
Dewatering Power	66,194	66,194	66,194	9,575	7,733	5,890	4,048	2,205	363	0
Class B Hauling	2,066,676	2,066,676	2,066,676	298,956	241,431	183,906	126,382	68,857	11,332	0
Total running costs	4,924,879	4,931,095	4,937,311	2,813,528	2,750,430	2,687,333	2,624,235	2,561,137	2,498,039	2,490,600
Net Benefit/(cost)	(2,845,394)	(2,848,890)	(2,851,014)	(2,191,048)	(2,110,548)	(2,030,369)	(1,950,507)	(1,870,960)	(1,791,729)	(1,780,912)
Expressed in escalated dollars with sensitivity adjustments										
Capital Outlays										
BUS + Interconnection	0	0	0	0	0	0	0	0	0	0
SCR	0	0	0	0	0	0	0	0	0	0
Dig 1&3 Improvements	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	0	0	0	0	0	0	0	0	0	0
Benefits:										
D3 RINs	3,195,990	3,277,835	3,360,335	3,443,457	3,527,166	3,611,423	3,696,190	3,781,424	3,867,079	3,953,109
D5 RINs	1,109,733	1,118,765	1,127,715	164,412	133,800	102,691	71,092	39,014	6,466	0
LCFS	1,613,474	1,644,381	1,675,444	1,680,469	1,650,721	1,620,183	1,588,846	1,556,713	1,523,786	1,540,761
Natural Gas Sale	800,121	825,041	850,638	863,464	858,527	853,047	847,004	840,378	833,149	853,372
HSW Tipping Fee	2,942,039	3,000,880	3,060,898	451,631	372,023	289,051	202,610	112,597	18,902	0
Total benefits	(9,661,357)	(9,866,902)	(10,075,029)	(6,603,432)	(6,542,236)	(6,476,394)	(6,405,743)	(6,330,126)	(6,249,382)	(6,347,242)
Discounted Benefits (in 2020$)	(7,363,353)	(7,336,593)	(7,308,631)	(4,673,428)	(4,517,189)	(4,362,660)	(4,209,823)	(4,058,661)	(3,909,162)	(3,873,537)
Annual Running Costs:										
Engine O&M	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
SCR O&M	310,719	318,075	325,601	333,300	341,178	349,237	357,482	365,917	374,546	383,374
Biogas Upgrading O&M	617,992	633,619	649,625	316,398	314,589	312,581	310,366	307,939	305,290	312,700
NC Demand	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	232,306	236,952	241,691	246,525	251,455	256,485	261,614	266,847	272,184	277,627
Natural Gas Purchased - Engine	635,080	650,115	665,497	681,234	697,334	713,806	730,658	747,898	765,536	783,580
Dig 1 & 5 O&M	746,025	760,945	776,164	791,687	807,521	823,671	840,145	856,948	874,087	891,568
Dewatering Polymer	59,153	60,336	61,543	9,081	7,480	5,812	4,074	2,264	380	0
Dewatering Power	82,304	83,950	85,629	12,634	10,407	8,086	5,668	3,150	529	0
Class B Hauling	2,569,652	2,621,045	2,673,466	394,466	324,934	252,464	176,965	98,345	16,509	0
Total running costs	5,563,949	5,683,112	5,804,815	3,118,625	3,096,076	3,071,378	3,044,454	3,015,223	2,983,606	3,032,225
Discounted Running Costs (in 2020$)	4,240,535	4,225,711	4,210,931	2,207,136	2,137,734	2,068,957	2,000,800	1,933,258	1,866,328	1,850,479
Net escalated benefit/(cost)	(4,097,408)	(4,183,791)	(4,270,214)	(3,484,807)	(3,446,160)	(3,405,016)	(3,361,289)	(3,314,903)	(3,265,776)	(3,315,017)
Life cycle cost analysis										
PVs in 2020	(3,122,818)	(3,110,882)	(3,097,700)	(2,466,293)	(2,379,455)	(2,293,704)	(2,209,023)	(2,125,403)	(2,042,833)	(2,023,059)
Cumulative Benefits Payback	(724,113)	(3,834,995)								
NPV as of 2020										

SOLIDS CALCULATIONS

Sludge Flows and Loads								
	AA		Max Month		Max 2-Week		Max-Day	
	Flow	VS Loads	Flow	VS Loads	Flow	VS Loads	Flow	VS Loads
Year	gpd	ppd			gpd	ppd	gpd	ppd
2020	220,934	71,222	270,138	87,001	284,656	91,646	348,593	112,150
2021	225,437	72,677	275,664	88,785	290,515	93,539	355,808	114,481
2022	229,940	74,133	281,191	90,569	296,375	95,432	363,024	116,812
2023	234,443	75,588	286,717	92,354	302,234	97,325	370,240	119,142
2024	238,946	77,044	292,243	94,138	308,094	99,218	377,455	121,473
2025	243,449	78,499	297,769	95,922	313,953	101,112	384,671	123,804
2026	247,953	79,954	303,295	97,706	319,813	103,005	391,887	126,135
2027	252,456	81,410	308,822	99,490	325,672	104,898	399,102	128,466
2028	256,959	82,865	314,348	101,275	331,531	106,791	406,318	130,796
2029	261,462	84,321	319,874	103,059	337,391	108,684	413,534	133,127
2030	265,965	85,776	325,400	104,843	343,250	110,577	420,749	135,458
2031	270,476	87,232	330,905	106,619	349,139	112,479	427,944	137,781
2032	274,987	88,688	336,410	108,395	355,028	114,381	435,138	140,104
2033	279,498	90,144	341,915	110,172	360,916	116,282	442,332	142,426
2034	284,010	91,600	347,420	111,948	366,805	118,184	449,526	144,749
2035	288,521	93,057	352,925	113,724	372,694	120,086	456,720	147,072
2036	293,032	94,513	358,429	115,500	378,582	121,988	463,915	149,395
2037	297,543	95,969	363,934	117,276	384,471	123,890	471,109	151,718
2038	302,054	97,425	369,439	119,053	390,360	125,791	478,303	154,040
2039	306,565	98,881	374,944	120,829	396,248	127,693	485,497	156,363
2040	311,076	100,337	380,449	122,605	402,137	129,595	492,692	158,686

Mesophilic + 2 Small Dig (HSW sent only to Dig 1&3)															
HRT Based Capacity			OLR Based Capacity												
Sludge	Omnivore Digester Capacity for FW	HSW	HSW	HSW	HSW Imported	**HSW**	**HSW TS**	**HSW VS**	**HSW VSR**	**HSW to Dewateri**	**Class B Disposal @ 22% TS**	**Dewatering Polymer**	**Dewatering Power**	**Class B Hauling**	**HSW Tip Fee**
gal	gal	gpd	ppd VS (0.35 OLR)	gpd	gpd	**gpd**	**ppd**	**ppd**	**ppd**	**ppd**	**wtpd**	**$/yr**	**$/yr**	**$/yr**	**$/yr**
3,314,003	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,381,550	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,449,098	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,516,646	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,584,194	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,651,742	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,719,290	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,786,838	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,854,386	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,921,933	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
3,989,481	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
4,057,147	600,000	40,000	28,075	33,003	33,003	33,003	33,029	28,075	22,460	10,569	24	9,688	13,480	420,853	481,842
4,124,812	575,188	38,346	26,914	31,638	31,638	31,638	31,663	26,914	21,531	10,132	23	9,287	12,922	403,449	461,916
4,192,477	507,523	33,835	23,748	27,916	27,916	27,916	27,938	23,748	18,998	8,940	20	8,195	11,402	355,987	407,576
4,260,143	439,857	29,324	20,582	24,194	24,194	24,194	24,214	20,582	16,465	7,748	18	7,102	9,882	308,525	353,236
4,327,808	372,192	24,813	17,415	20,472	20,472	20,472	20,489	17,415	13,932	6,556	15	6,010	8,362	261,063	298,896
4,395,474	304,526	20,302	14,249	16,750	16,750	16,750	16,764	14,249	11,399	5,364	12	4,917	6,841	213,601	244,556
4,463,139	236,861	15,791	11,083	13,028	13,028	13,028	13,039	11,083	8,866	4,172	9	3,824	5,321	166,139	190,216
4,530,804	169,196	11,280	7,917	9,307	9,307	9,307	9,314	7,917	6,334	2,980	7	2,732	3,801	118,677	135,876
4,598,470	101,530	6,769	4,751	5,585	5,585	5,585	5,589	4,751	3,801	1,789	4	1,639	2,281	71,215	81,536
4,666,135	33,865	2,258	1,585	1,863	1,863	1,863	1,864	1,585	1,268	597	1	547	761	23,754	27,196

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Technical Memorandum
FINAL

Prepared for: Encina Wastewater Authority

Project title: Biosolids, Energy, and Emissions

Project no.: 150871.300

Technical Memorandum 9.1

Subject: Encina Renewable Natural-gas Injection Feasibility Study

Date: March 27, 2019

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List of Abbreviations

$	dollar(s)
$/DGE	dollars per diesel gallons equivalents
$/MMscf	dollars per million standard cubic feet
$/therm	dollars per therm
$/year	dollars per year
AFRF	Alternative Fuel Receiving Facility
BEE	Biosolids Energy and Emission
Btu/cf	British thermal units per cubic foot/feet
cfm	cubic feet per minute
CO_2	carbon dioxide
DG	digester gas
EPA	Environmental Protection Agency
ERNI	Encina Renewable Natural-gas Injection
EWA	Encina Wastewater Authority
EWPCF	Encina Water Pollution Control Facility
FOG	fats, oil, and grease
FW	food waste
GCS	gas conditioning system
gpd	gallon(s) per day
H_2S	hydrogen sulfide
HSW	high-strength waste
kW	kilowatt(s)
kWh	kilowatt hour(s)
lb/cf-day	pound(s) per cubic feet per day
LCFS	Low Carbon Fuel Standard
M	million
MG	million gallons
muni sludge	municipal wastewater solids
O_2	oxygen gas
O&M	operations and maintenance
N/A	non applicable
N_2	nitrogen gas
NPV	net present value
PSA	pressure swing adsorption
psig	pounds per square inch gage
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RNG	renewable natural gas
RTO	regenerative thermal oxidizer
scf/lb VS	standard cubic feet per pound of volatile solids
scfm	standard cubic foot/feet per minute
SDG&E	San Diego Gas and Electric
SoCalGas	Southern California Gas Company
TM	technical memorandum
TS	total solids
TSA	temperature swing adsorption
Unison	Unison Solutions
VOC	volatile organic compound
VPSA	vacuum pressure swing adsorption
VS	volatile solids
VSR	volatile solids reduction

Acknowledgements

Brown and Caldwell acknowledges the valuable contributions made by the Encina Wastewater Authority (EWA) and Eco Engineers in conducting the Encina Renewable Natural-gas Injection (ERNI) Feasibility Study.

Specifically, the project team recognizes the following personnel for their efforts:

- Scott McClelland (EWA)
- Tucker Southern (EWA)
- Brad Pleima (Eco Engineers)
- Ellen Camara (Eco Engineers)

Executive Summary

This Technical Memorandum (TM) 9.1 describes the required steps for implementing the Encina Renewable Natural-gas Injection (ERNI) Project at the Encina Water Pollution Control Facility (EWPCF). The EWPCF currently operates three digesters for municipal solids and high-strength waste (HSW) digestion. The digester gas (DG) is beneficially used in either the internal combustion engines or biosolids thermal dryer. The purpose of this ERNI project is to evaluate the feasibility and benefits of sending upgraded DG, or renewable natural gas (RNG), to the San Diego Gas and Electric (SDG&E) natural gas pipeline. Environmental attributes are available through the Renewable Fuel Standard (RFS) and the Low Carbon Fuel Standard (LCFS) programs to offer financial incentives for upgrading DG to RNG for use as a transportation fuel.

This study compares various pipeline injection alternatives against Encina Wastewater Authority's (EWA's) current operation over a 10-year analysis period. Given the RFS regulations at the time of this analysis, D3 RNG generated from municipal sludge is approximately ten times more valuable than D5 RNG generated from the co-digestion feedstocks EWA receives (e.g., brewery waste and fats, oil, and grease [FOG]). "D3" and "D5" are two of the categories assigned by the Environmental Protection Agency (EPA) for types of renewable fuels. Because of the current D3 and D5 definitions and relative value under the RFS, the alternatives in this TM assume only D3 RNG is sent to the pipeline to maximize EWA's return on investment. Additionally, there are some risks related to the long-term viability of a pipeline injection project as the values for the environmental attributes and duration of these programs seems uncertain; hence, a 10-year net present value (NPV) is considered rather than a 20-year analysis.

The evaluation was based on the following assumptions:

- EWA will continue to accept the current volumes of brewery waste and FOG throughout the 10-year analysis period
- Three large digesters are in operation to digest municipal solids and accept HSW
- D3 RNG is sent to the pipeline while D5 DG is used in the existing engines
- Digester heating requirements are satisfied by supplemental heat with boiler operation (natural gas fueled) as needed.

The following alternatives were developed and evaluated:

- Alternative 0: Accept current amounts of FOG and brewery waste and use all DG in the existing cogeneration system.
- Alternative 0 – gas conditioning system (GCS): Accept current amounts of FOG and brewery waste and use all DG in the existing cogeneration system; install DG conditioning upstream of engines.
- Alternative 1: Municipal wastewater solids (muni sludge) digestion only (no FOG or brewery waste); all gas is upgraded and sent to the pipeline. Digester heat provided by boiler running on natural gas.
- Alternative 2: Separate feedstock digesters for D3 and D5. Some muni sludge is co-digested with HSW. D3 gas to pipeline; D5 gas to engines.
- Alternative 3: Accept food waste (FW) to co-digest with FOG and brewery waste. Separate digester feedstocks. D3 gas sent to pipeline; D5 gas sent to engines.
- Alternative 4: Accept FW to co-digest with FOG and brewery waste. Prioritize use of gas in engines with two D5 digesters. One D3 digester sending gas to pipeline.

The results of this analysis indicate that any pipeline injection project can provide financial benefits to EWA as shown in Figure ES-1. Alternative 0 assumes DG is sent to the engines while Alternatives 1 to 4 send upgraded D3 RNG to the pipeline.

Figure ES-1. Pipeline injection cost benefits

The results from this ERNI study show that DG upgrading to pipeline injection projects can offer financial benefits over the current operation of DG fired engines on a 10-year life-cycle cost. Alternative 3 provides the greatest NPV benefit over the baseline operation; however, it would require EWA to accept pre-processed FW as co-digestion feedstock. In general, the results of this feasibility study indicate that a pipeline injection project has the potential to provide a greater NPV benefit over the current operation, even in a 10-year analysis. While the RFS and LCFS programs may extend beyond 2030, it is uncertain what the marketplace for the environmental attributes will look like in the future. Hence, a 10-year analysis was performed. These pipeline injection projects still offer a 3- to 5-year return on investment and are viable projects for EWA to pursue.

All pipeline injection alternatives, regardless of digester feedstock separation, converged on a 500 standard cubic foot/feet per minute (scfm) gas upgrading system, the recommended system size for a pipeline injection project. Given the 500 scfm equipment sizing, membranes would be the recommended technology for DG upgrading based on installations of comparable size in North America.

The ERNI project is being put on hold due to the following barriers:

- Limited capital budget available due to other high-priority projects
- Uncertainty about future HSW and FW receiving volumes and resultant DG production
- Uncertainty about future RFS and LCFS values, including EPA's definition of D3/D5 fuels and separation requirements.

Considering these barriers, any one of the following developments would trigger EWA to resume project development:

- Successful procurement of grant funding offered for renewable fuel projects (EWA should continue to track these opportunities)
- Emergence of a strong partner for a public/private partnership where the private company would provide the capital financing for the project in exchange for revenue sharing (EWA should remain open to discussions with project developers)
- Emergence of a HSW or FW source which would increase DG production (EWA should remain open to discussions with local haulers)
- Changes to the RFS program which either increase D3 or D5 values, designate co-digestion feedstocks as the higher-valued D3 fuel, or remove the physical separation requirements for distinguishing between D3 and D5 fuels. Any of these changes would further increase the economic incentive to move forward with the project.

Section 1: Introduction

Brown and Caldwell recently submitted a comprehensive Biosolids Energy and Emission (BEE) Plan to Encina Wastewater Authority (EWA). Technical memorandum (TM) 7 of the BEE Plan developed various alternative scenarios for solids processing as well as energy production and digester gas (DG) utilization. This TM is an Encina Renewable Natural-gas Injection (ERNI) study that provides life-cycle costs as well as estimated capital costs associated with potential pipeline injection projects at the Encina Water Pollution Control Facility (EWPCF). EWA has indicated that TM 9.1 will be based on the assumption that three large digesters are in service and the engines will continue to operate on DG produced from co-digestion of high-strength waste (HSW). DG produced from the digestion of municipal sludge will be upgraded to renewable natural gas (RNG) and injected into the Southern California Gas Company (SoCalGas) pipeline.

1.1 Purpose and Scope

TM 9.1 evaluates the feasibility of installing gas separation equipment to upgrade DG to RNG at the EWPCF. This TM builds on the prior work done as part of the BEE project, which recommended EWA further evaluate the feasibility of a pipeline injection project. This TM provides a summary of the design criteria for the ERNI project, a gas upgrading technology overview and recommendation, a conceptual site and piping layout, and refined business case evaluation results.

This TM will be combined with the BEE project. The previous TMs associated with the BEE project include:

- TM 1: Baseline Energy Profiles and Projections
- TM 2: Technology Evaluations for Biosolids Handling
- TM 3: Technology Evaluations for Alternative Power Production
- TM 4: Technology Evaluations for Biogas Production
- TM 5: Technology Evaluations for Waste Heat
- TM 6: Air Emissions
- TM 7: Alternatives Development, Evaluation, and Selection
- TM 8: Grant and Incentive Programs Summary
- TM 9: High Strength Waste Feasibility Study

Section 2: Basis of Evaluation

This section summarizes the basis of evaluation and design criteria for the ERNI project. All alternatives assume three large digesters in service without any rehabilitation projects to put the small digesters in service.

2.1 Existing DG Production

As part of the BEE project, the existing DG production was evaluated based on feedstock characteristics of municipal wastewater solids (muni sludge) and HSW. The projections of DG and a discussion on the estimation of these values is summarized in TM 1. The EWA currently receives approximately 150,000 gallons per week (about 21,100 gallons per day) of fats, oil, and grease (FOG) and brewery waste for co-digestion. The DG projections in Table 2-1 are based on the assumption that EWA will continue to receive similar amounts of FOG and brewery waste in the future.

DG production estimates for the years included in the analysis are summarized in Table 2-1 using the solids loading rates associated Digesters 4, 5, and 6 in service (three large digesters). These DG production estimates will be used as the basis of evaluation to determine annual operations and maintenance (O&M) costs, sizing of the DG upgrading system, and capital costs.

Table 2-1. Annual Average Projected DG Production, scfm

Year	DG from Sludge	DG from FOG and Brewery Waste	Total DG
2020	446	87	533
2021	456	87	543
2022	465	87	552
2023	475	87	562
2024	485	87	572
2025	494	87	581
2026	504	87	591
2027	513	87	600
2028	523	87	610
2029	532	87	619

scfm = standard cubic foot/feet per minute

2.2 Co-digestion Parameters

EWA provided metering logs of the quantities of FOG and brewery waste that were delivered between September and December 2018. On average, EWA accepted 10,500 gallons per day (gpd) of FOG and 10,600 gpd of brewery waste; however deliveries are generally only received on weekdays. The normal delivery quantities are therefore 14,700 gpd of FOG and 14,840 gpd of brewery waste Monday through Friday, and no weekend deliveries. With this delivery schedule, the average weekday gas production will be higher than weekend gas production. This weekly cycle was not incorporated into the analysis. As the project progresses with further analysis and development, delivery load leveling measures should be considered, such as scheduling weekend deliveries or increased HSW storage.

All alternatives evaluated in this TM assume EWA will continue to accept the same quantities of FOG and brewery waste for co-digestion. These assumptions, as well as other parameters on all feedstocks used in this evaluation, are summarized in Table 2-2.

Table 2-2. Digestion Parameters and Assumptions

Feed Characteristics		Sludge	FOG	Brewery Waste	FW
TS	(%)	4.5	5.5	5	16
VS	(%)	84.6	95	98	90
SG		1.0	0.9	1.0	1.0
VSR		63%	90%	90%	80%
Gas Prod. Rate	scf/lb VS	15	18	15	15
Flow	gpd		10,500	10,600	

scf/lb VS = standard cubic feet per pound of volatile solids
TS = total solids
VSR = volatile solids reduction

To determine the available capacities of the digesters, the digestion design parameters summarized in Table 2-3 were assumed. Additionally, the analysis assumed the volatile solids (VS) contribution from FOG does not exceed more than 30 percent of the overall digester load to prevent an upset in the digesters.

Table 2-3. Digestion Design Parameters for HSW Capacity Analysis

Parameter	Units	D3 Digesters	D5 Digesters
Organic loading rate	lb/cf-day	0.18	0.5
Hydraulic residence time	days	15	15
Active capacity	MG	2.05	2.05

lb/cf-day = pound(s) per cubic feet per day
MG = million gallons

2.3 RNG Specifications

Upgraded DG will be routed to the San Diego Gas and Electric (SDG&E) natural gas pipeline located West of Avenida Encinas, which is owned by SoCal Gas. SoCalGas Rule No. 30 (Transportation of Customer-owned Gas) provides requirements for gas to be injected into the utility pipeline. The requirements for DG upgrading under SoCalGas Rule 30 are included at https://www.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf. DG upgraded to pipeline quality natural gas under the ERNI project would meet Rule 30 regulations.

In addition to meeting the fuel specifications, EWA would also be subject to two agreements regarding uniform flow and operational imbalance. To summarize these agreements, gas injected to the SoCalGas pipeline must be delivered on a uniform hourly basis equal to 1/24 (+/- 5 percent) of the total daily scheduled quantities for a particular gas flow day. If EWA does not abide by this provision, SoCalGas can suspend service until action is taken to ensure compliance or install a flow control device at EWA's cost. If EWA deviates by more than 10 percent from uniform daily deliveries more often than they are complying, SoCalGas also reserves the right to suspend service. This agreement drives the ERNI project towards a DG upgrading system sized for a constant flow gas production to avoid being penalized for variable RNG delivered to the pipeline. To avoid being penalized for variations in RNG production, EWA can manage operations such that a set quantity of RNG is delivered to the pipeline by including a setpoint for the biogas upgrading system. Any excess gas will be utilized in the engines or thermal dryer, thereby eliminating storage requirements to buffer out any variations.

2.4 EPA Renewable Fuel Standard Regulations

Under current regulations, RNG produced from municipal wastewater sludge is characterized as D3 (cellulosic) biofuel category as shown under row Q of Table 1 to § of CFR 80.1426, while RNG produced from food waste, FOG, or other high strength organic wastes are characterized as D5 (advanced) biofuel category under row T. Current EPA interpretation considers RNG produced from comingled D3 and D5 feedstocks to be classified as entirely D5 biofuel. Based on recent RIN trading values, a D5 RIN has been valued at between 10 and 15 percent of the monetary value of a D3 RIN. Therefore, physical separation of D3 and D5 digester feedstocks is encouraged to maximize potential RIN revenue from producing RNG. The alternatives in this TM take the EPA Renewable Fuel Standard (RFS) regulations into account, hence D3 gas is prioritized for pipeline injection while D5 gas is prioritized for the engines.

Section 3: Pipeline Injection Alternatives

This feasibility study evaluates several pipeline injection alternatives that are coupled with a few co-digestion scenarios. Since the value of environmental attributes called renewable identification numbers (RINs) associated with pipeline injection of natural gas for use as vehicle fuel varies depending on the type of digester feedstock used to generate that fuel, several scenarios were analyzed to review the financial and operational impacts. Baseline alternatives were evaluated both with and without a gas conditioning system (GCS). DG generated from muni sludge qualifies for a D3 cellulosic RIN, currently valued at $2 per RIN, while DG generated from FOG, brewery waste, FW, and other HSW qualifies for a D5 RIN advanced biofuel, currently valued at $0.25 per RIN. Co-digesting muni sludge and HSW feedstocks generates a D5 RIN; therefore, separating D3 and D5 feedstocks provides the greatest return on investment for a DG upgrading system. The list of alternatives evaluated are as follows:

- Alternative 0: Accept current amounts of FOG and brewery waste and use all DG in the existing cogeneration system.
- Alternative 0 – GCS: Accept current amounts of FOG and brewery waste and use all DG in the existing cogeneration system; install DG conditioning upstream of engines.
- Alternative 1: Muni sludge digestion only (no FOG or brewery waste); all gas is upgraded and sent to the pipeline. Digester heat provided by boiler running on natural gas.
- Alternative 2: Separate feedstock digesters for D3 and D5. Some muni sludge is co-digested with HSW. D3 gas to pipeline; D5 gas to engines.
- Alternative 3: Accept FW to co-digest with FOG and brewery waste. Separate digester feedstocks. D3 gas sent to pipeline; D5 gas sent to engines.
- Alternative 4: Accept FW to co-digest with FOG and brewery waste. Prioritize use of gas in engines with two D5 digesters. One D3 digester sending gas to pipeline.

Table 2-4 summarizes these alternatives in terms of co-digestion feedstocks, the number of D3 and D5 digesters, and expected DG production.

Table 3-1. List of Pipeline Injection Alternatives							
Alternative	Co-digestion	No. of D3 Digesters	No. of D5 Digesters	2020 DG, cfm	2020 D3 DG, scfm	2020 D5 DG, scfm	DG Use
0	FOG + Brewery	0	3	533	0	533	All to engines
0 - GCS	FOG + Brewery	0	3	533	0	533	All to engines
1	No	3	0	446	446	0	All to pipeline - D3
2	FOG + Brewery	2	1	533	412	122	D3 to pipeline; D5 to engines
3	FOG + Brewery + FW	2	1	577	446	131	D3 to pipeline; D5 to engines
4	FOG + Brewery + FW	1	2	533	285	249	D3 to pipeline; D5 to engines

cfm = cubic feet per minute

Section 4: DG Upgrading Technologies

A broad range of available technologies, both in North America and Europe, were considered in this technology screening. This section describes the manufacturers and type of technologies reviewed, the evaluation criteria used to perform an initial screening of technologies, and the results of the criteria comparison. Common to all alternatives, a thermal oxidizer or regenerative thermal oxidizer (RTO) is required to safely dispose of reject gas from the upgrading process. Since EWA already has an RTO on site for the thermal dryer, a future design project should evaluate whether it has capacity and can be repurposed for DG upgrading off gas. This study assumes a new RTO is required, but future efforts may demonstrate that it is feasible to use the existing unit.

4.1 Technologies Considered

Four technologies for DG upgrading were reviewed in the conceptual-level technology screening. The list below represents the technologies known to Brown and Caldwell that are currently marketed in the United States for DG upgrading and several European manufacturers that have shown some intent on marketing in the United States. The list below identifies the main technology used for gas separation:

- Membranes
- Pressure swing adsorption (PSA)
- Chemical solvent
- Water solvent

Attributes that are considered for each DG upgrading technology include the following:

- Power use
- Methane capture
- Non-regenerating media consumption
- Capital cost
- O&M cost
- Footprint
- Complexity/familiarity

4.2 Membranes

The two manufacturers who provide membranes for DG upgrading are Unison Solutions (Unison) and Air Liquide; Unison packages systems up to 600 scfm and Air Liquide packages systems greater than 400 scfm.

Membranes are thin, semi-permeable barriers that selectively separate carbon dioxide (CO_2) from DG. The driving force for the process is differential partial pressures with a high pressure on the process side and low pressure on the waste side. The CO_2 dissolves and diffuses through the thin, non-porous membranes faster than methane does. The selectivity for CO_2 is not as high as adsorbents or solvents and, as a result, a two-stage process is usually required to maintain higher overall methane capture efficiency. The waste gas from the second-stage membranes has a high methane concentration and is recycled to the suction of the compression system to improve methane recovery. The waste gas from the first-stage membranes in the Unison system has a low methane concentration and would be combusted in a thermal oxidizer.

Membranes also remove residual water and hydrogen sulfide (H_2S), although H_2S can degrade the membrane life, and to a lesser degree oxygen gas (O_2) and nitrogen gas (N_2) from DG. Membranes are subject to degradation if volatile organic compound (VOC), siloxanes, or H_2S are sent through the membranes, so these constituents must be removed upstream. H_2S removal is generally the first process in the system and is achieved with a scavenging media such as iron sponge or granular iron oxide. The Unison system then requires DG compression to 160 to 200 pounds per square inch gage (psig) with cooling and moisture removal and siloxane and VOC removal. Figure 4-1 below shows the activated carbon beds for VOC/siloxane removal and membranes from a 100 scfm Unison installation in San Mateo, California.

Figure 4-1. DG upgrading system at the
San Mateo Wastewater Treatment Plant (California) using Unison's BioCNG system

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

The system can reportedly achieve a 93 percent methane recovery (meaning 93 percent of the methane in the DG ends up in the product gas) while recycling 35 percent of the inlet gas flow from the second-stage membranes. A higher methane capture rate can be achieved with this technology, but the recycle rate from the second-stage membranes increases, which increases power consumption. At 93 percent methane recovery, the unit power requirement is about 7 kilowatt hours (kWh) per 1,000 standard cubic feet (scf). At 95 percent methane recovery, the unit power requirement would increase to 7.7 kWh per 1,000 scf. The system can be turned down to 25 percent without performance degradation. Air Liquide and Unison standardize the design for a 95 percent methane recovery rate and both vendors can meet pipeline specifications with membranes as proven with the Point Loma installation.

Unison and Air Liquide both provided an equipment quote and footprint for a 500 scfm system:

- Unison:
  - Budgetary quote: $2.2 million
  - Skid Dimensions: 12 feet by 28 feet
  - Chiller Dimensions: 68 inches by 90 inches
  - Estimated layout dimensions: 30 feet by 35 feet
- Air Liquide:
  - Budgetary quote: $1.5 million
  - Layout dimensions: 35 feet by 50 feet

4.3 Pressure Swing Adsorption

PSA systems are multiple packed beds which operate continuously by having one vessel “online” and the other(s) in a state of regeneration. PSA systems take advantage of the difference in equilibrium capacities of adsorbents, which are porous materials that have high surface areas per volume used as a molecular sieve. For a DG upgrading system, the adsorbent will be selective towards CO_2 at high pressures.

Guild is one of the leading manufacturers that provide a PSA system for DG. Greenlane also packages PSA systems but does not provide the Molecular Gate media that is highly selective to CO_2 (discussed later in this section). The Guild system compresses the raw DG to 100 psig which then flows through one of four vessels packed with adsorbent where the CO_2 is removed. When the online bed reaches its capacity (as measured by a CO_2 analyzer on the discharge) it is isolated from the process, and the DG flows through a newly regenerated packed bed. The spent bed is regenerated by depressurizing the vessel and drawing a deep vacuum on the vessel using vacuum pumps. Figure 4-2 shows a process flow diagram of the PSA system.

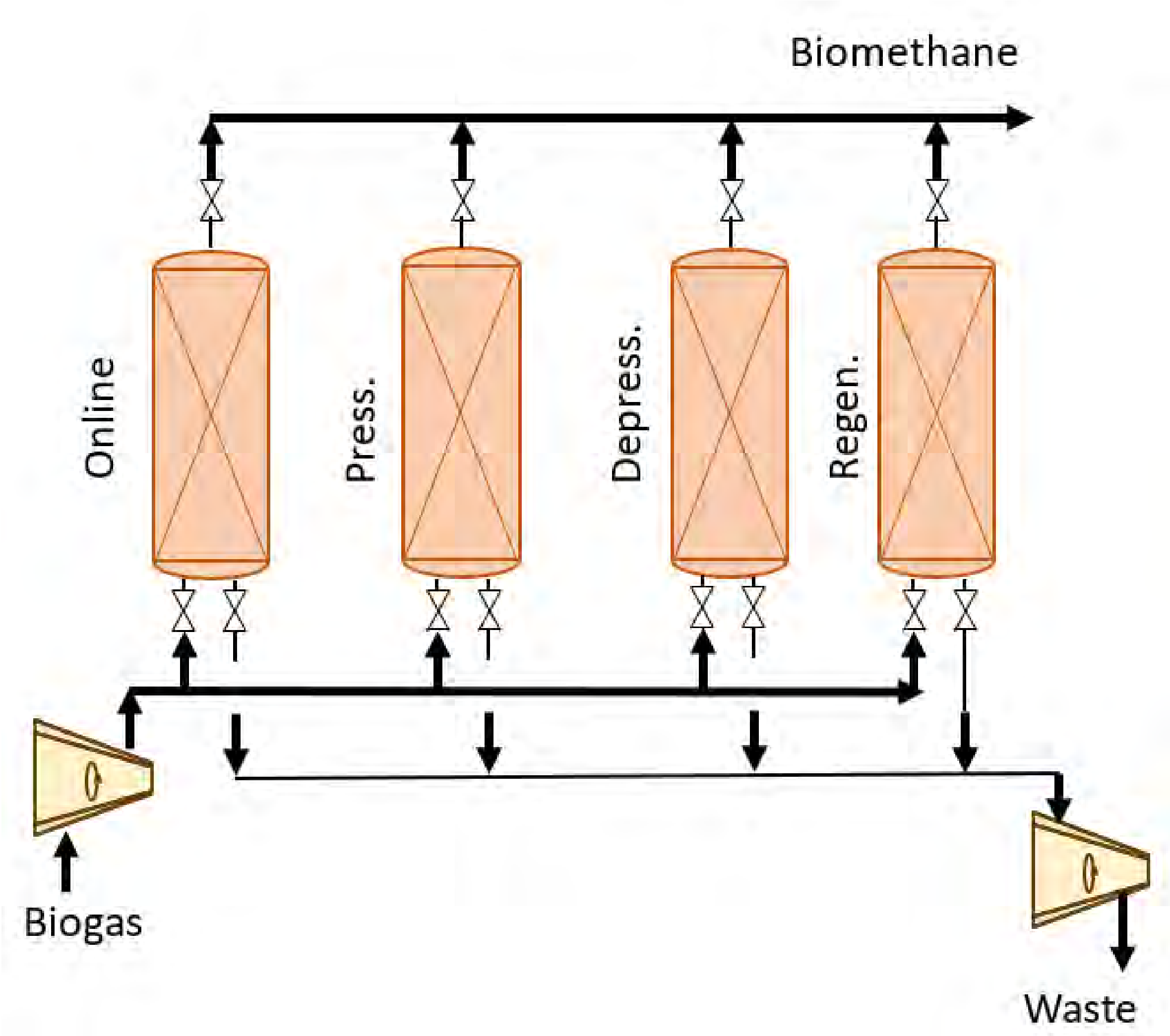

Figure 4-2. PSA system profess flow diagram

The inherent batch-nature of this process requires buffer vessels to smooth out pressure, flow, and gas composition fluctuations. The buffer vessels store and release gas to re-pressurize beds coming back online from the regeneration step and to buffer pressure fluctuations in the product gas. Waste gas from the regeneration step is variable in flow and composition. A tail gas buffer vessel stores the waste gas, which is then metered out at a constant flow and near constant composition to the thermal oxidizer for combustion. Figure 4-3 shows the 1,250 scfm Guild PSA system installed at the Dos Rios Water Reclamation Facility in San Antonio, Texas.

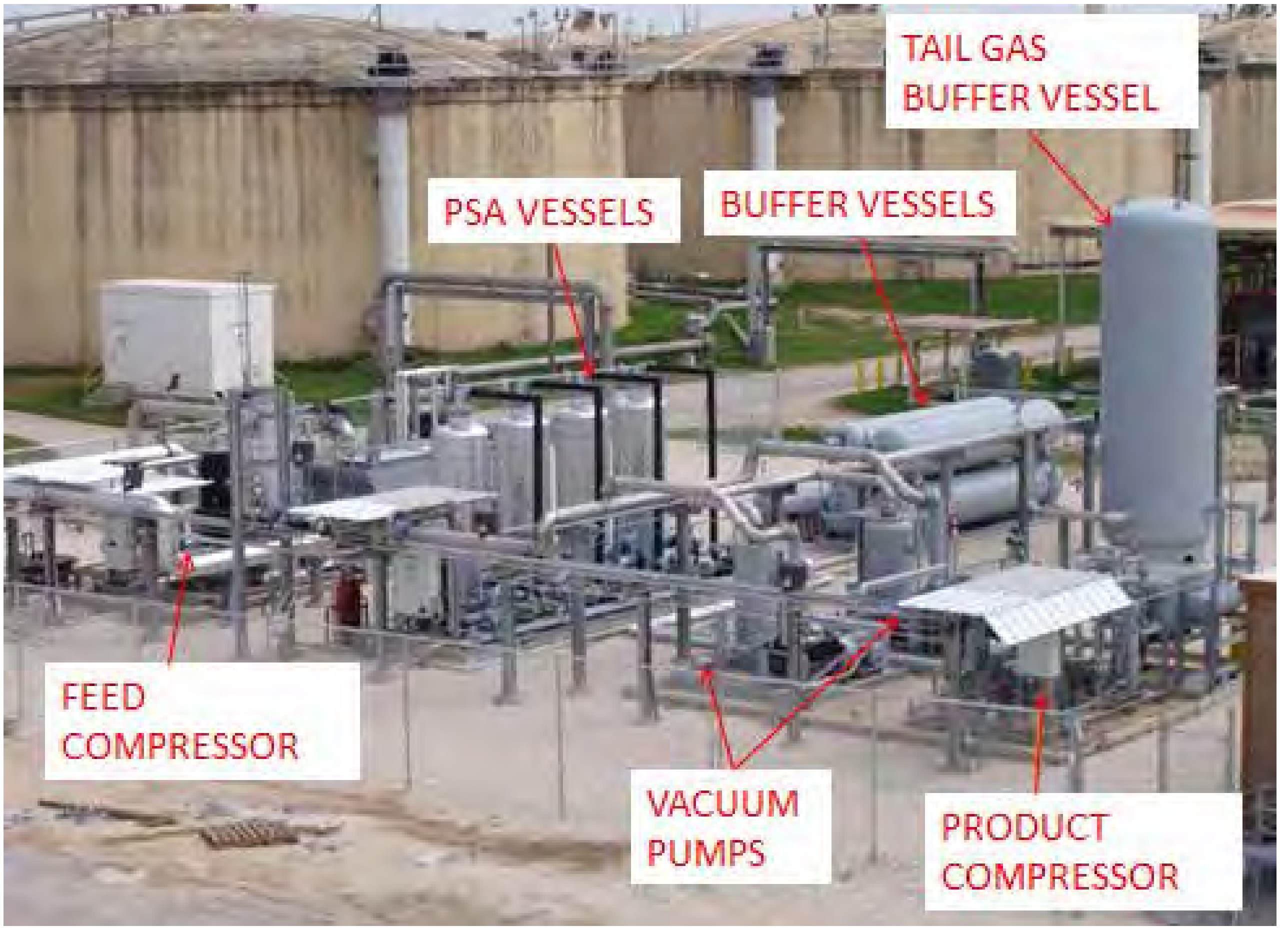

Figure 4-3. Guild system at Dos Rios Water Reclamation Facility, San Antonio, Texas

The Guild system is unique in that its proprietary molecular sieve adsorbent can be used to remove CO_2, H_2S, VOCs, siloxanes, and moisture in a single step in comparison to the Unison system that requires separate vessels to remove these constituents. The Guild media would also remove about 20 percent of the N_2 from the DG, which would assist in meeting the SoCalGas Rule 30 quality requirements to a small degree. Guild is the sole licensor of BASF Group's Molecular Gate® media that undergoes a specialized manufacturing process to make it highly selective. Unlike other PSA manufacturers, gas treatment is not required upstream of its system to protect the adsorbent (Greenlane's system requires activated carbon upstream of the PSA to remove H_2S and siloxanes). A pre-cooling heat exchanger can be installed to cool the raw DG to approximately 80 to 85 degrees Fahrenheit to remove bulk moisture, therefore decreasing the potential for corrosion downstream. Condensate that condenses out of the gas during compression and cooling would contain a portion of the VOCs and siloxanes as well. The pressure leaving the PSA vessels is about 90 psig.

Guild and Greenlane claim the PSA technology can achieve 95 percent methane recovery. This recovery rate would effectively be reduced to about 92 to 93 percent when the DG inlet methane concentrations are at 60 percent because the waste gas does not have enough energy to keep the combustion chamber of the thermal oxidizer hot. A support gas (either natural gas or biomethane) is required to keep the chamber hot. A higher methane concentration at the inlet would reduce the amount of support gas required. The unit power requirement is 7.7 kWh per 1,000 scf. The Guild system can remove CO_2 down to a concentration of 1 percent or less.

Greenlane and Guild provided equipment quotes and footprints for a 500 scfm system:

- Greenlane:
  - Budgetary quote: $1.5 million
  - Layout dimensions: 48 feet by 33 feet
- Guild:
  - Budgetary quote: non applicable (N/A). No quote provided.
  - Layout dimensions: 45 feet by 40 feet

4.4 Solvents

Two types of solvent absorption technologies are available for DG upgrading to RNG: water and amine. Both technologies operate under a similar concept that the solvent selectively absorbs CO_2 and other constituents from DG while allowing methane to pass through the vessel with little absorption. Absorption is the transfer process of a gas constituent into a liquid in which it is soluble.

In general, raw DG is compressed prior to entering the scrubber vessel, where it enters at the bottom of the tower above the liquid level. The DG pressure is controlled to optimize for selective absorption of CO_2 over methane while also removing H_2S, some VOCs, and siloxanes. A solvent is then added at the top of the absorption column above the packing material. DG flows upward through the packing material where CO_2 is selectively absorbed by the solvent, allowing methane to flow counter currently to the top of the scrubbing vessel. The compressed gas exits the scrubber vessel with CO_2 levels reduced to 1 percent to meet RNG specifications. Figure 4-4 shows a simplified process flow diagram of the solvent system.

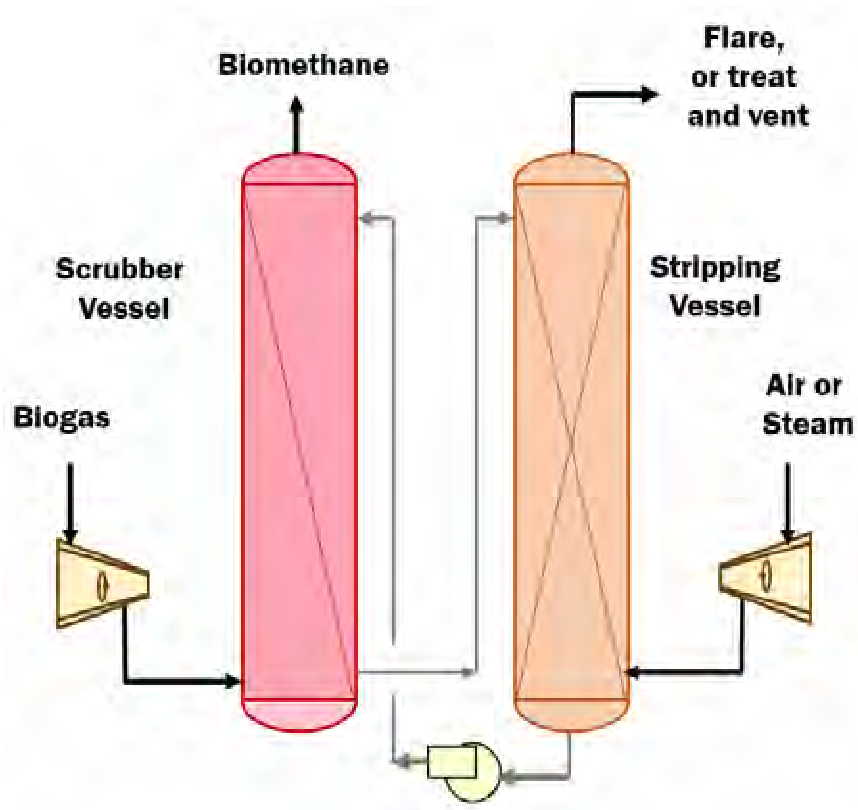

Figure 4-4. Simplified process flow diagram of solvent system for DG upgrading

In solvent systems, H_2S must be removed in one of two locations: the raw DG or the waste gas. H_2S must be removed to prevent it from being discharged with the vent gas and posing an odor concern. H_2S would likely be removed with a scavenging media such as iron sponge, iron hydroxide, or SulfaTreat. Removing H_2S upstream reduces the potential for corrosion through the system and may require low-pressure booster blowers to accommodate the pressure drop of the H_2S removal system without resulting in a vacuum at the inlet of the system.

4.4.1 Water Solvents

Greenlane is one of the recognized water solvent vendors in the industry with several North America installations and is the basis of evaluation for this study. DG is first compressed to about 135 psig. The DG and compressor oil are then cooled with air-cooled radiators (an intercooler and aftercooler), allowing for condensate that contains portions of the condensable VOCs and siloxanes to form downstream of the radiators.

The standard Greenlane system uses a closed water solvent loop that is regenerated in a two-stage process. The first regeneration step reduces the pressure of the saturated water from the scrubber vessel pressure of 130 psig to a pressure of 30 psig in a flashing vessel. Reducing the pressure of the water causes some of the dissolved gases to evolve from the water including enough methane to warrant capture. The flash gas is recycled to the suction of the first inlet compressor to improve the methane recovery rate of the system. The second stage of regeneration occurs when the saturated water is dropped to atmospheric pressure and run downward through another packed tower, the stripping vessel. A blower pushes air up through the vessel, which strips the remaining CO_2, H_2S, and methane out of solution. The waste gas mixture of air, CO_2, H_2S, and methane is scrubbed of H_2S and vented, or combusted, in an RTO. The regenerated water is then chilled and pumped back to the top of the packed tower. A chiller is used to cool the water and improve its capacity for absorption prior to reentering the scrubber vessel. Small flows of fresh makeup water to the water loop and wastewater from the water loop maintain proper water quality for absorption. Figure 4-5 below is a picture of the 1,100 scfm Greenlane Totara system process vessels installed at the Fair Oaks Dairy.

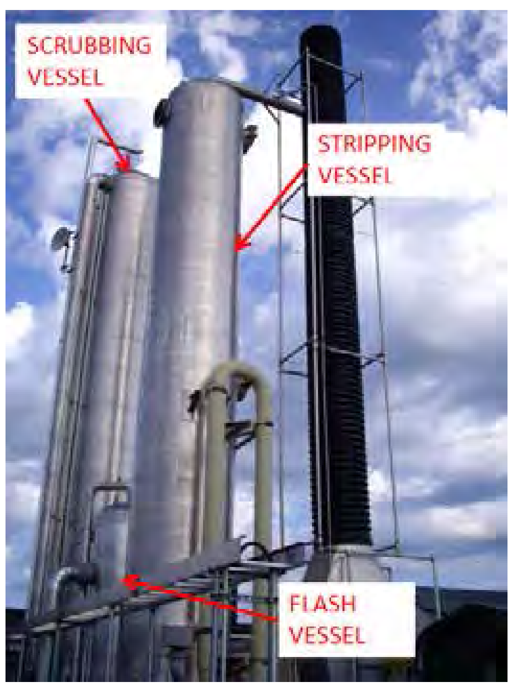

Figure 4-5. Greenlane Totara plus process vessels at Fair Oaks Dairy in Indiana

A vacuum pressure swing adsorption (VPSA) system may be required to reduce O_2 and further reduce CO_2 from the product gas. O_2 and N_2 levels get elevated in the product gas leaving the scrubber vessel because the water solvent entering the scrubber vessel is saturated with N_2 and O_2 from air in the stripping vessel. Without additional separation, the O_2 levels in the product gas may exceed the Rule 30 requirement for O_2 at 0.2 percent, and the additional N_2 might mean the required heating value could not be met even at 1 percent CO_2 in the product gas. One of the drawbacks of the water solvent system is that it does not remove O_2. In order to remove O_2, a VPSA system is required, which would result in an additional 2 percent methane loss.

The product gas leaving the scrubber vessel would need further processing to cool, dry, compress, and possibly remove O_2 to meet the product gas quality requirements. The solvent-saturated product gas is first dried through a dual-vessel temperature swing adsorption (TSA)/PSA dryer. The gas that is depressurized from and used to regenerate the TSA/PSA dryer beds is sent back to the suction of the compressor. The dry gas leaving the TSA/PSA would require compression to meet pipeline requirements.

Greenlane typically guarantees a methane recovery rate of 96 percent with the standard closed-loop system including 2 percent methane loss from the VPSA system for O_2 reduction, and 98 percent with the once-through system. The unit power requirement is 8.0 kWh per 1,000 scf for the standard system with a VPSA, and 11.1 kilowatts (kW) per 1,000 scf for the once-through system. For the standard Greenlane systems, the makeup water would be only 4 gallons per minute and is assumed to be potable water. Greenlane normally designs systems to remove CO_2 to 2 percent, but can achieve a CO_2 concentration of 1 percent or less in the product gas to meet Rule 30 by installing systems that are designed for a higher flow rate and running them at a lower DG flow rate.

Brown and Caldwell contacted Greenlane for a water solvent quote, but Greenlane recommended a PSA system with upstream activated carbon since a VPSA system would still be required for the water solvent technology to remove CO_2 and O_2 from the product gas and would increase costs.

4.4.2 Amine Solvents

Amine solvent systems operate in a similar method to the water solvent technology, but the main difference is a chemical solvent is used instead of water. Amines have the advantage of having a very high selectivity towards CO_2 and has no affinity to methane and can, therefore, provide higher methane capture efficiencies up to 99.9 percent. Two of the manufacturers that can provide equipment in North America are Morrow Renewables and Puregas Solutions. Any remaining H_2S still left in the clean gas is removed in an H_2S polishing vessel. The product gas is then compressed to pipeline pressure prior to being sent to the metering station.

In discussing the project with Puregas Solutions, the supplier did not feel that the cost associated with an amine system was competitive with a membrane system of EWPCF's size range, but still provided a budgetary quote for the smallest system. Morrow Renewables also provided a quote.

Morrow Renewables provided an equipment quote and footprint for a 500 scfm system, but not provide a layout drawing:

- $2.7 million (M)
- Layout Dimensions: N/A. Vendor did not provide a footprint.

Puregas Solutions provided an equipment quote and footprint for an 800 scfm system:

- $2.5M
- Layout Dimensions: 50 feet wide by 35 feet long

4.5 Summary of Gas Upgrading Technologies

The four technologies considered for installation at EWPCF to upgrade DG gas to RNG for pipeline injection are summarized in Table 4-1.

Table 4-1. Summary of DG Upgrading Technologies

Technology	Vendors[a]	Vendor Quote	Footprint[b]	% Methane Recovery	Operating Cost	O&M Complexity	Power Required, kWh/1,000 scf
Membranes	Unison Air Liquide	\$2.2M \$1.5M	50' x 35'	95	Moderate - pre-treatment media consumption. Membrane replacement every 10 years.	Simple – fewest moving parts	7.7
PSA	Greenlane Guild	\$1.5M N/A	48' x 50'	92 to 95	Moderate - media requires replacement every 10 years.	Moderate	7.7
Water Solvents	N/A	N/A	N/A[c]	98%	Low	Moderate	8 to 11
Amine Solvents	Puregas Solutions Morrow Renewables	\$2.5M \$2.7M	50' x 35'[c]	>99	High - chemical consumption and requires H_2S reduction upstream	Complex	9[d]

a. *Vendors that provided quotes or recommend technology for EWPCF's basis of evaluation listed.*

b. *If two vendors provided information, the largest possible footprint is shown in the table for conservative siting assumptions.*

c. *Solvent systems may have scrubber vessel heights up to 48'.*

d. *Gross consumption. Approximately 10-14 kWh/1,000 scf can be recovered as useable heat; actual amount dependent on design conditions and layout.*

Given the DG upgrading equipment capacity required for the ERNI project, the membrane technology is the best apparent technology based on a low capital cost, high methane recovery rate, and moderate power requirements. Capital costs for ERNI alternatives will be developed assuming membranes as the basis of design.

Section 5: Present Worth Cost Analysis

The following subsections describe the various assumptions made on capital costs, operating costs, and benefits along with results from the present worth cost analysis.

5.1 Capital Costs

Cost assumptions were made on the following items, which are required for the EWPCF to beneficially reuse DG through pipeline injection for use as vehicle fuel. Detailed cost estimating was not performed but costs available from relevant projects around Northern and Southern California were used assuming a membrane technology for gas upgrading. Given the size of the gas upgrading system required, membranes are generally the most suited technology that is cost competitive.

Table 5-1 provides a summary of capital cost investments required for each alternative and the equipment sizing assumptions. The costs shown are Class V planning-level costs.

Table 5-1. Summary of Capital Costs for Pipeline Injection Alternatives[a]		
Alternative	Capital Cost	Assumptions
0	$0.0M	No capital
0 - GCS	$3.0M	Gas conditioning for 550 scfm
1	$13.5M	DG upgrading for 500 scfm. Pipeline interconnection. Standby boiler
2	$13.0M	DG upgrading for 500 scfm. Pipeline interconnection
3	$13.0M	DG upgrading for 500 scfm. Pipeline interconnection
4	$12.0M	DG upgrading for 400 scfm. Pipeline interconnection

a. *Costs shown in 2020 dollars.*

5.2 Operating Costs

To the best degree possible, the following operating cost estimates reflect the actual operating parameters and unit costs at EWPCF. Information was requested during the BEE Plan from EWA staff for utilities such as water, natural gas, and electricity and are used in this evaluation.

The following Table 5-2 summarizes the unit costs used for operating cost analysis.

Table 5-2. Summary of Unit Costs and Operating Assumptions		
Parameter	Unit	Cost
Natural Gas Sale	$/therm	0.25
Cogen O&M with GCS	$/kWh	0.015
Cogen O&M without GCS	$/kWh	0.025
DG upgrading O&M	$/MMscf	1,100
Gas Conditioning O&M	$/kWh	0.005
Alternative 1 Boiler O&M	$/year	15,000
Electricity	$/kWh	0.09
Non-coincident demand charge	$/kW	24.51
DG upgrading labor	$/year	125,000
DG upgrading methane recovery	%	95
DG upgrading uptime	%	95
DG heating value, lower heating value	Btu/cf	560

$/MMscf = dollars per million standard cubic feet
$/therm = dollars per therm
$/year = dollars per year
Btu/cf = British thermal units per cubic foot/feet

The following operating assumptions are consistent amongst all alternatives:

- No HSW tipping fees are included in the benefits. The revenue from tipping fees is assumed to be approximately equal to the increase in costs from O&M of the Alternative Fuel Receiving Facility (AFRF) and increased solids load contributing to the downstream processes.
- Digester heating demands are satisfied in all alternatives, including the additional heat required for increased HSW co-digestion. Natural gas is used in the boiler to meet additional heating demands if the engines on D5 gas cannot satisfy the full heating demands.
- Savings from cogeneration assume non-coincident demand charges are avoided each month since two redundant engines (out of four) are available. This is a conservative assumption that may favor cogeneration alternatives.
- All renewable fuel produced is sold to an off-taker and all RINs and Low Carbon Fuel Standard (LCFS) credits are sold to an obligated party.
- All pipeline injection alternatives assume an additional (one) full-time employee for O&M.

Table 5-3 summarizes the annual costs for each alternative. All costs are compared assuming 2020 operating conditions to maintain consistency.

Table 5-3. Annual Operating Costs for All Alternatives for Year 2020

Alternative	Annual O&M Costs	Contributing Costs
0	$0.6M	O&M: engines Natural gas for dryer
0 - GCS	$0.5M	O&M: engines, gas conditioning Natural gas for dryer
1	$0.9M	O&M: DG upgrading, labor, boiler Running costs: power for DG upgrading, natural gas for digester heat and dryer
2	$0.9M	O&M: engines, DG upgrading, labor Running costs: power for DG upgrading, natural gas for digester heat and dryer
3	$1.0M	O&M: engines, DG upgrading, labor Running costs: power for DG upgrading, natural gas for digester heat and dryer
4	$0.9M	O&M: engines, DG upgrading, labor Running costs: power for DG upgrading, natural gas for dryer

5.3 Benefits

Table 5-4 shows a summary of benefit cost assumptions used in the analysis. The D3, D5, and LCFS credit values all assumed a 1 percent deflation value over the 10-year analysis as there is uncertainty in future values of these attributes. Note that these values have been updated to reflect the current market value for RINs since the initial BEE project. The current market values have been updated to reflect January 2019 pricing; actual revenue is de-rated to account for broker and verification fees that subtract from the RIN revenue.

Table 5-4. Summary of Benefit Unit Costs		
Parameter	Unit	Cost
D3 RIN value	$	1.75
D5 RIN value	$	0.25
LCFS value	$/DGE	0.80
Natural Gas Sale	$/therm	0.25
Avoided electricity costs	$/kWh + $/kW (engine output)	0.09 24.51

$/DGE = dollars per diesel gallons equivalents
$/therm dollars per therm

Attachment A includes a calculation that summarizes the annual estimated revenue from pipeline injection for RINs, LCFS, the commodity value of the fuel, and electricity. These economic benefits range from approximately $3 to $5M annually, with the D3 RIN revenue generating approximately half of the total. Table 5-5 summarizes the annual benefits for all alternatives using projections on year 2020.

Table 5-5. Annual Benefits for All Alternatives for Year 2020				
Alternative	RIN Revenue	LCFS Revenue	Power Savings	Total Revenue
0	$0.0M	$0.0M	$2.0M	$2.0M
0 - GCS	$0.0M	$0.0M	$2.0M	$2.0M
1	$2.6M	$0.7M	$0.0M	$3.7M
2	$2.4M	$0.9M	$0.4M	$4.1M
3	$2.6M	$1.2M	$0.5M	$4.7M
4	$1.7M	$0.9M	$0.9M	$3.8M

5.4 Results

A present worth cost analysis was performed to identify capital and operating costs associated with DG upgrading for natural gas pipeline injection. The analysis uses an escalation rate of 2.0 percent and a discount rate of 2.5 percent performed over a 10-year period from 2020 to 2029. The analysis was ultimately used to determine the net benefits of each alternative in comparison to the status quo operation of running engines on DG. A summary of the net present value (NPV) results from this feasibility study are included in Table 5-6.

Table 5-6. Summary of Business Case Evaluation Results							
Alternative	Description	Capital	Annual Revenue	Annual Costs	10-year NPV	10-year NPV Benefit over Baseline	2020 DG, cfm
0	All gas to engines, no GCS	$0.0 M	($2.0M)	$0.6M	($14.7M)	$0.0M	533
0 - GCS	GCS 550 scfm; all gas to engines	$3.0 M	($2.0M)	$0.5M	($12.5M)	$2.2M	533
1	DG Upgrading 500 scfm; three digesters (D3)	$13.5 M	($3.7M)	$0.9M	($15.0M)	($0.3M)	446
2	DG Upgrading 500 scfm; three digesters (two D3, one D5)	$13.0 M	($4.1M)	$0.9M	($19.4M)	($4.7M)	533
3	DG Upgrading 500 scfm; three digesters (two D3, one D5)	$13.0 M	($4.7M)	$1.0M	($25.5M)	($10.8M)	577
4	DG Upgrading 400 scfm; three digesters (one D3, two D5)	$12.0 M	($3.8M)	$0.9M	($17.5M)	($2.8M)	533

red = negative values

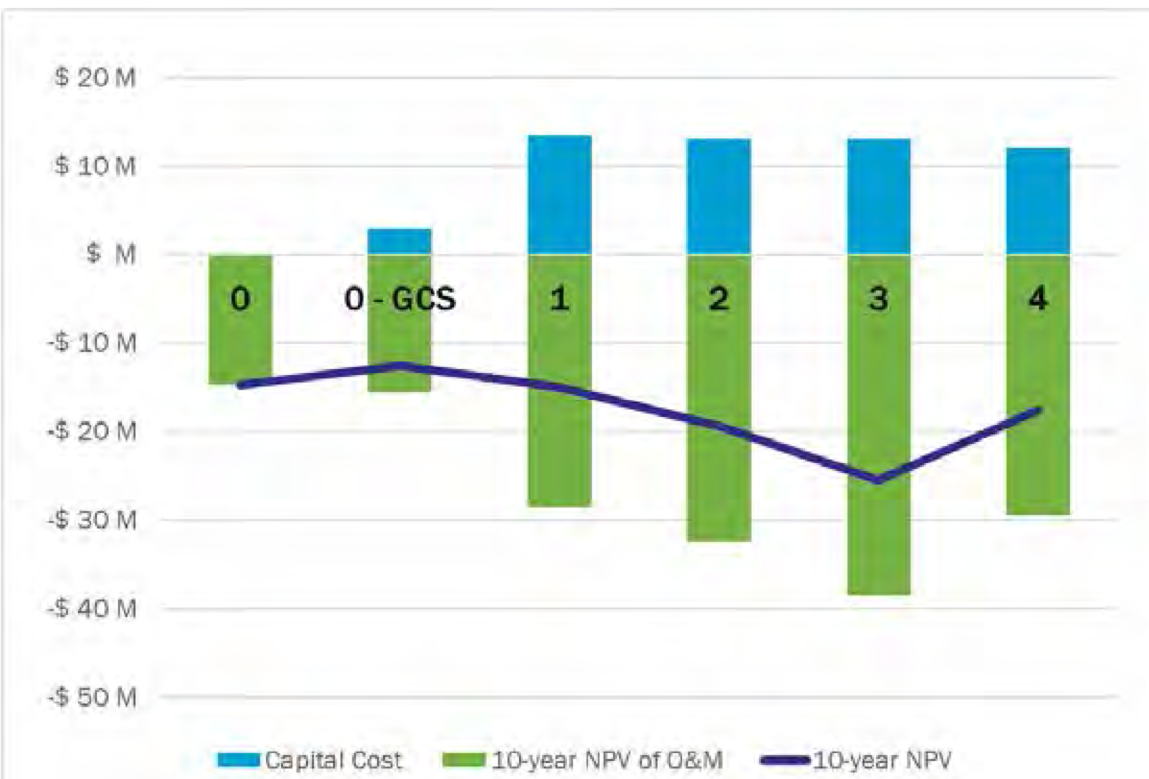

Figure 5-1. Summary of 10-year NPV results

Alternative 3 provides the greatest NPV benefit over the baseline operation; however, it would require EWA to accept FW as co-digestion feedstock. If EWA is able to accept FW to stabilize the FOG in a separate D5 digester, less municipal sludge would be required in the D5 digester, allowing EWA to maximize revenue from the RFS program. This alternative may be a more feasible option in the future as California Senate Bill No. 1383 will require solid waste haulers to divert organics from landfills, thereby creating an organics marketplace. AFRF improvements could potentially be required to accommodate FW introduced to the HSW mix, as it may increase pumping requirements.

Alternatives 2 and 4 are also attractive and minimize the risks of accepting FW as a feedstock. Maintaining two D3 digesters provides a slight economic benefit over the single D3 digester operation; however, both offer an increase in revenue over the current operation. In general, the results of this feasibility study indicate that a pipeline injection project has the potential to provide a greater NPV benefit over the current operation, even in a 10-year analysis. While the RFS and LCFS programs may extend beyond 2030, it is uncertain what the marketplace for the environmental attributes will look like in the future. Hence, a 10-year analysis was performed. These pipeline injection projects still offer a 3- to 5-year return on investment and are viable projects for EWA to pursue.

All alternatives converge on a DG upgrading system of roughly 500 scfm, the recommended system size for a pipeline injection project. As previously mentioned, the technology assumed in developing the capital costs is conventional gas conditioning followed by membrane separation.

Section 6: Summary

The results from this ERNI study show that DG upgrading to pipeline injection projects can offer financial benefits over the current operation of DG-fired engines on a 10-year life-cycle cost. At the time of this evaluation, the Environmental Protection Agency RFS regulations require separate digester feedstocks for municipal sludge and HSW feedstocks to maintain separate D3 and D5 RINs. Should regulations on the D3 and D5 feedstocks change, the results of this analysis would be impacted, and EWA should continue to monitor the RFS program and RIN market. It is also recommended that EWA continue to track grant and funding opportunities offered by the California Public Utilities Commission, SoCalGas, the California Energy Commission, and others to potentially reduce capital costs of a pipeline injection project.

All pipeline injection alternatives, regardless of digester feedstock separation, converged on a 500 scfm gas upgrading system. Based on the 500 scfm DG upgrading system, there are no foreseen issues with siting equipment at the EWPCF. Potential locations were selected by EWA, but the evaluation ceased prior to a full siting analysis. Given the 500 scfm equipment sizing, membranes would be the recommended technology for DG upgrading based on installations of comparable size in North America.

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Attachment A: Calculations

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Alternative 0 Results

		Risk adjustments (+/- percent):			**Alternative**
Year of analysis	**2020**		**Benefits**	**0%**	**HSW Study Alternative**
Escalation rate	**2.00%**		**Capital costs**	**0%**	**Life Cycle Alternative Cost Analysis ($)**
Discount rate	**2.50%**		**Running costs**	**0%**	

Year

Expressed in 2020 dollars, unescalated -- dollars

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital Outlays											
	Total capital outlays	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:											
	Power Savings	1,960,919	1,996,036	2,031,153	2,066,270	2,101,386	2,136,503	2,171,620	2,206,736	2,241,853	2,276,970
	Total benefits	**(1,960,919)**	**(1,996,036)**	**(2,031,153)**	**(2,066,270)**	**(2,101,386)**	**(2,136,503)**	**(2,171,620)**	**(2,206,736)**	**(2,241,853)**	**(2,276,970)**
Annual Running Costs:	Engine O&M	396,705	403,810	410,914	418,018	425,122	432,227	439,331	446,435	453,540	460,644
	GCS O&M										
	Natural Gas Purchased - Dryer	186,835	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844
	Total running costs	**583,540**	**590,646**	**597,751**	**604,856**	**611,962**	**619,067**	**626,172**	**633,278**	**640,383**	**647,488**
Net Benefit/(cost)		**(1,377,379)**	**(1,405,390)**	**(1,433,402)**	**(1,461,413)**	**(1,489,425)**	**(1,517,436)**	**(1,545,447)**	**(1,573,459)**	**(1,601,470)**	**(1,629,482)**

Expressed in escalated dollars with sensitivity adjustments

			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital Outlays												
		0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
	Total capital outlays (Pvs)		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:												
		0	0	0	0	0	0	0	0	0	0	0
	Power Savings		1,960,919	2,035,957	2,113,211	2,192,742	2,274,608	2,358,872	2,445,596	2,534,846	2,626,688	2,721,190
		0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
	Total benefits		**(1,960,919)**	**(2,035,957)**	**(2,113,211)**	**(2,192,742)**	**(2,274,608)**	**(2,358,872)**	**(2,445,596)**	**(2,534,846)**	**(2,626,688)**	**(2,721,190)**
	Discounted Benefits (in 2020$)		**(1,960,919)**	**(1,986,299)**	**(2,011,385)**	**(2,036,179)**	**(2,060,683)**	**(2,084,899)**	**(2,108,830)**	**(2,132,478)**	**(2,155,845)**	**(2,178,934)**
Annual Running Costs:	Engine O&M		396,705	411,886	427,515	443,604	460,166	477,213	494,758	512,814	531,394	550,512
	GCS O&M		0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
	Natural Gas Purchased - Dryer		186,835	190,573	194,385	198,274	202,241	206,287	210,413	214,623	218,917	223,296
		0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
	Total running costs		**583,540**	**602,459**	**621,900**	**641,878**	**662,407**	**683,500**	**705,172**	**727,437**	**750,311**	**773,808**
	Discounted Running Costs (in 2020$)		**583,540**	**587,764**	**591,934**	**596,048**	**600,108**	**604,114**	**608,067**	**611,967**	**615,815**	**619,610**
				0								
Net escalated benefit/(cost)			**(1,377,379)**	**(1,433,498)**	**(1,491,311)**	**(1,550,863)**	**(1,612,201)**	**(1,675,372)**	**(1,740,425)**	**(1,807,410)**	**(1,876,378)**	**(1,947,381)**

Life cycle cost analysis

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PVs in 2020	(1,377,379)	(1,398,535)	(1,419,452)	(1,440,131)	(1,460,575)	(1,480,785)	(1,500,763)	(1,520,511)	(1,540,030)	(1,559,323)
Cumulative Benefits Payback	**(1,377,379)**	**(2,775,914)**	**(4,195,365)**	**(5,635,496)**	**(7,096,071)**	**(8,576,856)**	**(10,077,618)**	**(11,598,129)**	**(13,138,160)**	**(14,697,483)**
NPV as of 2020	**(14,697,483)**									

Alternative 0-GCS Results

Year of analysis	2020	Risk adjustments (+/- percent):	
Escalation rate	2.00%	Benefits	0%
Discount rate	2.50%	Capital costs	0%
		Running costs	0%

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Expressed in 2020 dollars, unescalated -- dollars											
Capital Outlays											
	Gas Conditioning - 650 scfm	3,000,000									
	Total capital outlays	3,000,000	0	0	0	0	0	0	0	0	0
Benefits:											
	Power Savings	1,960,919	1,996,036	2,031,153	2,066,270	2,101,386	2,136,503	2,171,620	2,206,736	2,241,853	2,276,970
	Total benefits	(1,960,919)	(1,996,036)	(2,031,153)	(2,066,270)	(2,101,386)	(2,136,503)	(2,171,620)	(2,206,736)	(2,241,853)	(2,276,970)
Annual Running Costs:											
	Engine O&M	238,023	242,286	246,548	250,811	255,073	259,336	263,599	267,861	272,124	276,386
	GCS O&M	79,341	80,762	82,183	83,604	85,024	86,445	87,866	89,287	90,708	92,129
	Natural Gas Purchased - Dryer	186,835	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844
	Total running costs	504,199	509,884	515,568	521,253	526,937	532,622	538,306	543,990	549,675	555,359
Net Benefit/(cost)		1,543,280	(1,486,152)	(1,515,585)	(1,545,017)	(1,574,449)	(1,603,881)	(1,633,314)	(1,662,746)	(1,692,178)	(1,721,610)
Expressed in escalated dollars with sensitivity adjustments											
Capital Outlays											
	Gas Conditioning - 650 scfm	3,000,000	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	Total capital outlays (Pvs)	3,000,000	0	0	0	0	0	0	0	0	0
Benefits:											
	0	0	0	0	0	0	0	0	0	0	0
	Power Savings	1,960,919	2,035,957	2,113,211	2,192,742	2,274,608	2,358,872	2,445,596	2,534,846	2,626,688	2,721,190
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	Total benefits	(1,960,919)	(2,035,957)	(2,113,211)	(2,192,742)	(2,274,608)	(2,358,872)	(2,445,596)	(2,534,846)	(2,626,688)	(2,721,190)
	Discounted Benefits (in 2020$)	(1,960,919)	(1,986,299)	(2,011,385)	(2,036,179)	(2,060,683)	(2,084,899)	(2,108,830)	(2,132,478)	(2,155,845)	(2,178,934)
Annual Running Costs:											
	Engine O&M	238,023	247,131	256,509	266,163	276,100	286,328	296,855	307,688	318,836	330,307
	GCS O&M	79,341	82,377	85,503	88,721	92,033	95,443	98,952	102,563	106,279	110,102
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	Natural Gas Purchased - Dryer	186,835	190,573	194,385	198,274	202,241	206,287	210,413	214,623	218,917	223,296
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	Total running costs	504,199	520,081	536,397	553,158	570,374	588,057	606,220	624,874	644,032	663,706
	Discounted Running Costs (in 2020$)	504,199	507,397	510,551	513,662	516,730	519,757	522,742	525,685	528,587	531,448
			0								
Net escalated benefit/(cost)		1,543,280	(1,515,875)	(1,576,814)	(1,639,584)	(1,704,234)	(1,770,815)	(1,839,376)	(1,909,972)	(1,982,656)	(2,057,484)
Life cycle cost analysis											
PVs in 2020		1,543,280	(1,478,903)	(1,500,834)	(1,522,517)	(1,543,952)	(1,565,142)	(1,586,088)	(1,606,793)	(1,627,258)	(1,647,486)
Cumulative Benefits Payback		1,543,280	64,377	(1,436,457)	(2,958,974)	(4,502,927)	(6,068,069)	(7,654,157)	(9,260,950)	(10,888,209)	(12,535,694)
NPV as of 2020		(12,535,694)									

Alternative 1 Results

		Risk adjustments (+/- percent):		
Year of analysis	2020	Benefits	0%	
Escalation rate	2.00%	Capital costs	0%	
Discount rate	2.50%	Running costs	0%	

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Expressed in 2020 dollars, unescalated -- dollars											
Capital Outlays											
	BUS 500 scfm	13,000,000									
	Standby Boiler	500,000									
	HSW Receiving Facility										
	Dig 1&3 Improvements										
	Total capital outlays	**13,500,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:											
	D3 RINs	2,614,137	2,642,543	2,669,795	2,695,894	2,720,840	2,744,633	2,767,272	2,788,759	2,809,092	2,828,271
	LCFS	713,315	721,068	728,506	735,621	742,430	748,924	755,103	760,961	766,511	771,746
	Natural Gas Sale	328,475	335,503	342,531	349,559	356,587	363,615	370,643	377,671	384,699	391,727
	HSW Tipping Fee	0	0	0	0	0	0	0	0	0	0
	Total benefits	**(3,655,927)**	**(3,699,113)**	**(3,740,832)**	**(3,781,075)**	**(3,819,857)**	**(3,857,172)**	**(3,893,019)**	**(3,927,391)**	**(3,960,302)**	**(3,991,745)**
Annual Running Costs:											
	Engine O&M	0	0	0	0	0	0	0	0	0	0
	BUS Labor	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000
	Biogas/GCS Upgrading O&M	245,183	250,429	255,675	260,921	266,167	271,413	276,659	281,905	287,151	292,396
	NG - Digester Heat	96,633	98,684	100,735	102,785	104,836	106,886	108,937	110,987	113,038	115,089
	Natural Gas Purchased - Dryer	186,835	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844
	BUS Power	200,223	204,507	208,791	213,075	217,358	221,642	225,926	230,210	234,494	238,778
	Boiler O&M	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
	Total running costs	**868,874**	**880,456**	**892,037**	**903,619**	**915,200**	**926,782**	**938,363**	**949,945**	**961,526**	**973,108**
Net Benefit/(cost)		**10,712,948**	**(2,818,657)**	**(2,848,795)**	**(2,877,456)**	**(2,904,657)**	**(2,930,391)**	**(2,954,656)**	**(2,977,446)**	**(2,998,775)**	**(3,018,637)**
Expressed in escalated dollars with sensitivity adjustments											
Capital Outlays											
	BUS 500 scfm	13,000,000	0	0	0	0	0	0	0	0	0
	Standby Boiler	500,000	0	0	0	0	0	0	0	0	0
	Dig 1&3 Improvements	0	0	0	0	0	0	0	0	0	0
	Total capital outlays (Pvs)	**13,500,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:											
	D3 RINs	2,614,137	2,695,394	2,777,655	2,860,905	2,945,125	3,030,297	3,116,398	3,203,407	3,291,298	3,380,046
		0	0	0	0	0	0	0	0	0	0
	LCFS	713,315	735,489	757,937	780,647	803,630	826,873	850,369	874,105	898,089	922,308
	Natural Gas Sale	328,475	342,213	356,369	370,955	385,981	401,460	417,404	433,826	450,737	468,150
	HSW Tipping Fee	0	0	0	0	0	0	0	0	0	0
	Total benefits	**(3,655,927)**	**(3,773,095)**	**(3,891,961)**	**(4,012,507)**	**(4,134,737)**	**(4,258,630)**	**(4,384,172)**	**(4,511,337)**	**(4,640,124)**	**(4,770,504)**
	Discounted Benefits (in 2020$)	**(3,655,927)**	**(3,681,069)**	**(3,704,425)**	**(3,726,011)**	**(3,745,867)**	**(3,764,008)**	**(3,780,457)**	**(3,795,231)**	**(3,808,366)**	**(3,819,878)**
Annual Running Costs:											
	Engine O&M	0	0	0	0	0	0	0	0	0	0
	BUS Labor	125,000	127,500	130,050	132,651	135,304	138,010	140,770	143,586	146,457	149,387
	Biogas/GCS Upgrading O&M	245,183	255,438	266,004	276,891	288,107	299,662	311,563	323,820	336,443	349,441
	NG - Digester Heat	96,633	100,658	104,804	109,076	113,478	118,011	122,681	127,490	132,442	137,542
	Natural Gas Purchased - Dryer	186,835	190,573	194,385	198,274	202,241	206,287	210,413	214,623	218,917	223,296
	BUS Power	200,223	208,597	217,226	226,116	235,276	244,711	254,430	264,439	274,747	285,362
	Boiler O&M	15,000	15,300	15,606	15,918	16,236	16,561	16,892	17,230	17,575	17,926
	Total running costs	**868,874**	**898,065**	**928,076**	**958,927**	**990,642**	**1,023,242**	**1,056,749**	**1,091,188**	**1,126,581**	**1,162,954**
	Discounted Running Costs (in 2020$)	**868,874**	**876,161**	**883,356**	**890,459**	**897,473**	**904,397**	**911,232**	**917,978**	**924,638**	**931,210**
			0								
Net escalated benefit/(cost)		**10,712,948**	**(2,875,031)**	**(2,963,886)**	**(3,053,579)**	**(3,144,094)**	**(3,235,388)**	**(3,327,422)**	**(3,420,150)**	**(3,513,543)**	**(3,607,551)**
Life cycle cost analysis											
PVs in 2020		10,712,948	(2,804,908)	(2,821,069)	(2,835,552)	(2,848,394)	(2,859,612)	(2,869,226)	(2,877,253)	(2,883,729)	(2,888,668)
Cumulative Benefits Payback		**10,712,948**	**7,908,040**	**5,086,970**	**2,251,418**	**(596,976)**	**(3,456,588)**	**(6,325,813)**	**(9,203,066)**	**(12,086,795)**	**(14,975,463)**
NPV as of 2020		(14,975,463)									

Alternative 2 Results

Year of analysis	2020	Benefits	0%
Escalation rate	2.00%	Capital costs	0%
Discount rate	2.50%	Running costs	0%

Risk adjustments (+/- percent):

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

Expressed in 2020 dollars, unescalated -- dollars

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital Outlays										
BUS 500 scfm	13,000,000									
Total capital outlays	**13,000,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:										
D3 RINs	2,410,450	2,436,000	2,477,125	2,500,400	2,522,625	2,559,900	2,579,850	2,598,750	2,616,600	2,648,800
Power Savings	446,969	446,969	446,969	446,969	446,969	446,969	446,969	446,969	446,969	446,969
LCFS	852,234	858,555	864,561	870,252	875,621	880,683	885,430	889,862	893,973	897,776
Natural Gas Sale	392,447	399,475	406,503	413,531	420,559	427,587	434,616	441,644	448,672	455,700
HSW Tipping Fee										
Total benefits	**(4,102,101)**	**(4,140,999)**	**(4,195,158)**	**(4,231,153)**	**(4,265,775)**	**(4,315,140)**	**(4,346,865)**	**(4,377,225)**	**(4,406,214)**	**(4,449,245)**
Annual Running Costs:										
Engine O&M	90,424	90,424	90,424	90,424	90,424	90,424	90,424	90,424	90,424	90,424
BUS Labor	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000
Biogas/GCS Upgrading O&M	226,163	231,409	236,655	241,901	247,147	252,393	257,639	262,884	268,130	273,376
Natural Gas Purchased - Dig Heat	47,788	49,754	51,721	53,688	55,654	57,621	59,588	61,555	63,521	65,488
Natural Gas Purchased - Dryer	186,835	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844
BUS Power	239,217	243,501	247,785	252,069	256,353	260,637	264,921	269,205	273,489	277,773
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
Total running costs	**915,427**	**926,925**	**938,422**	**949,920**	**961,418**	**972,915**	**984,413**	**995,910**	**1,007,408**	**1,018,906**
Net Benefit/(cost)	**9,813,327**	**(3,214,075)**	**(3,256,736)**	**(3,281,233)**	**(3,304,357)**	**(3,342,224)**	**(3,362,452)**	**(3,381,315)**	**(3,398,806)**	**(3,430,339)**

Expressed in escalated dollars with sensitivity adjustments

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital Outlays										
BUS 500 scfm	13,000,000	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**13,000,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:										
D3 RINs	2,410,450	2,484,720	2,577,201	2,653,444	2,730,570	2,826,336	2,905,330	2,985,147	3,065,764	3,165,561
Power Savings	446,969	455,909	465,027	474,327	483,814	493,490	503,360	513,427	523,696	534,170
LCFS	852,234	875,726	899,489	923,518	947,800	972,345	997,138	1,022,172	1,047,432	1,072,925
Natural Gas Sale	392,447	407,465	422,926	438,843	455,227	472,091	489,448	507,310	525,690	544,603
HSW Tipping Fee	0	0	0	0	0	0	0	0	0	0
Total benefits	**(4,102,101)**	**(4,223,819)**	**(4,364,643)**	**(4,490,133)**	**(4,617,412)**	**(4,764,263)**	**(4,895,276)**	**(5,028,056)**	**(5,162,582)**	**(5,317,260)**
Discounted Benefits (in 2020$)	**(4,102,101)**	**(4,120,799)**	**(4,154,330)**	**(4,169,535)**	**(4,183,147)**	**(4,210,914)**	**(4,221,181)**	**(4,229,929)**	**(4,237,171)**	**(4,257,680)**
Annual Running Costs:										
Engine O&M	90,424	92,233	94,078	95,959	97,878	99,836	101,833	103,869	105,947	108,066
BUS Labor	125,000	127,500	130,050	132,651	135,304	138,010	140,770	143,586	146,457	149,387
Biogas/GCS Upgrading O&M	226,163	236,037	246,216	256,707	267,519	278,662	290,143	301,972	314,157	326,710
Natural Gas Purchased - Dig Heat	47,788	50,749	53,811	56,974	60,242	63,618	67,106	70,707	74,425	78,264
Natural Gas Purchased - Dryer	186,835	190,573	194,385	198,274	202,241	206,287	210,413	214,623	218,917	223,296
BUS Power	239,217	248,371	257,796	267,498	277,485	287,764	298,344	309,232	320,436	331,964
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
Total running costs	**915,427**	**945,463**	**976,335**	**1,008,063**	**1,040,669**	**1,074,177**	**1,108,609**	**1,143,988**	**1,180,339**	**1,217,687**
Discounted Running Costs (in 2020$)	**915,427**	**922,403**	**929,289**	**936,086**	**942,795**	**949,416**	**955,950**	**962,397**	**968,759**	**975,036**
		0								
Net escalated benefit/(cost)	**9,813,327**	**(3,278,356)**	**(3,388,308)**	**(3,482,070)**	**(3,576,742)**	**(3,690,086)**	**(3,786,667)**	**(3,884,068)**	**(3,982,243)**	**(4,099,573)**

Life cycle cost analysis

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PVs in 2020	9,813,327	(3,198,396)	(3,225,040)	(3,233,448)	(3,240,352)	(3,261,498)	(3,265,231)	(3,267,531)	(3,268,412)	(3,282,644)
Cumulative Benefits Payback	**9,813,327**	**6,614,930**	**3,389,890**	**156,442**	**(3,083,910)**	**(6,345,408)**	**(9,610,640)**	**(12,878,171)**	**(16,146,583)**	**(19,429,227)**
NPV as of 2020	**(19,429,227)**									

Alternative 3 Results

Alternative
HSW Study Alternative
Life Cycle Alternative Cost Analysis ($)

		Risk adjustments (+/- percent):	
Year of analysis	**2020**	**Benefits**	**0%**
Escalation rate	**2.00%**	**Capital costs**	**0%**
Discount rate	**2.50%**	**Running costs**	**0%**

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Expressed in 2020 dollars, unescalated -- dollars											
Capital Outlays											
	BUS 500 scfm	13,000,000									
	SCR										
	HSW Receiving Facility										
	Small Dig Improvements										
	Total capital outlays	13,000,000	0	0	0	0	0	0	0	0	0
Benefits:											
	D3 RINs	2,614,150	2,637,600	2,676,625	2,697,800	2,717,925	2,737,000	2,770,950	2,787,750	2,803,500	2,833,600
	Power Savings	481,326	481,326	481,326	481,326	481,326	481,326	481,326	481,326	481,326	481,326
	LCFS	1,188,790	1,208,460	1,228,130	1,247,800	1,267,470	1,287,130	1,306,800	1,326,470	1,346,140	1,365,800
	Natural Gas Sale	424,805	431,833	438,861	445,889	452,917	459,945	466,973	474,001	481,029	488,057
	HSW Tipping Fee										
	Total benefits	(4,709,071)	(4,759,219)	(4,824,942)	(4,872,815)	(4,919,638)	(4,965,401)	(5,026,049)	(5,069,547)	(5,111,995)	(5,168,783)
Annual Running Costs:											
	Engine O&M	97,375	97,375	97,375	97,375	97,375	97,375	97,375	97,375	97,375	97,375
	BUS Labor	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000
	Biogas/GCS Upgrading O&M	245,183	250,429	255,675	260,921	266,167	271,413	276,659	281,905	287,151	292,396
	Natural Gas Purchased - Dig Heat	45,439	47,406	49,372	51,339	53,306	55,272	57,239	59,206	61,172	63,139
	Natural Gas Purchased - Dryer	186,835	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844
	BUS Power	258,941	263,225	267,509	271,793	276,077	280,361	284,644	288,928	293,212	297,496
	Total running costs	958,773	970,270	981,768	993,265	1,004,763	1,016,261	1,027,758	1,039,256	1,050,754	1,062,251
Net Benefit/(cost)		9,249,702	(3,788,948)	(3,843,174)	(3,879,549)	(3,914,875)	(3,949,140)	(3,998,291)	(4,030,291)	(4,061,242)	(4,106,532)
Expressed in escalated dollars with sensitivity adjustments											
Capital Outlays											
	BUS 500 scfm	13,000,000	0	0	0	0	0	0	0	0	0
	SCR	0	0	0	0	0	0	0	0	0	0
	Small Dig Improvements	0	0	0	0	0	0	0	0	0	0
	Total capital outlays (Pvs)	13,000,000	0	0	0	0	0	0	0	0	0
Benefits:											
	D3 RINs	2,614,150	2,690,352	2,784,761	2,862,927	2,941,969	3,021,869	3,120,540	3,202,248	3,284,747	3,386,414
	Power Savings	481,326	490,952	500,772	510,787	521,003	531,423	542,051	552,892	563,950	575,229
	LCFS	1,188,790	1,232,629	1,277,746	1,324,175	1,371,950	1,421,096	1,471,669	1,523,697	1,577,218	1,632,257
	Natural Gas Sale	424,805	440,469	456,591	473,181	490,252	507,816	525,887	544,478	563,602	583,273
	HSW Tipping Fee	0	0	0	0	0	0	0	0	0	0
	Total benefits	(4,709,071)	(4,854,403)	(5,019,869)	(5,171,070)	(5,325,174)	(5,482,204)	(5,660,147)	(5,823,316)	(5,989,517)	(6,177,174)
	Discounted Benefits (in 2020$)	(4,709,071)	(4,736,003)	(4,777,984)	(4,801,853)	(4,824,345)	(4,845,469)	(4,880,727)	(4,898,953)	(4,915,876)	(4,946,239)
Annual Running Costs:											
	Engine O&M	97,375	99,323	101,309	103,335	105,402	107,510	109,660	111,853	114,090	116,372
	BUS Labor	125,000	127,500	130,050	132,651	135,304	138,010	140,770	143,586	146,457	149,387
	Biogas/GCS Upgrading O&M	245,183	255,438	266,004	276,891	288,107	299,662	311,563	323,820	336,443	349,441
	Natural Gas Purchased - Dig Heat	45,439	48,354	51,367	54,481	57,700	61,025	64,460	68,009	71,673	75,457
	Natural Gas Purchased - Dryer	186,835	190,573	194,385	198,274	202,241	206,287	210,413	214,623	218,917	223,296
	BUS Power	258,941	268,489	278,316	288,428	298,834	309,541	320,556	331,888	343,545	355,536
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	Total running costs	958,773	989,676	1,021,431	1,054,061	1,087,588	1,122,034	1,157,423	1,193,778	1,231,125	1,269,488
	Discounted Running Costs (in 2020$)	958,773	965,537	972,213	978,801	985,301	991,715	998,042	1,004,284	1,010,442	1,016,515
			0								
Net escalated benefit/(cost)		9,249,702	(3,864,727)	(3,998,438)	(4,117,009)	(4,237,586)	(4,360,170)	(4,502,725)	(4,629,538)	(4,758,392)	(4,907,686)
Life cycle cost analysis											
PVs in 2020		9,249,702	(3,770,466)	(3,805,771)	(3,823,052)	(3,839,044)	(3,853,755)	(3,882,685)	(3,894,669)	(3,905,434)	(3,929,723)
Cumulative Benefits Payback		9,249,702	5,479,236	1,673,465	(2,149,587)	(5,988,631)	(9,842,386)	(13,725,071)	(17,619,740)	(21,525,174)	(25,454,897)
NPV as of 2020		(25,454,897)									

Alternative 4 Results

		Risk adjustments (+/- percent):	
Year of analysis	2020	Benefits	0%
Escalation rate	2.00%	Capital costs	0%
Discount rate	2.50%	Running costs	0%

Alternative
HSW Study Alternative
ife Cycle Alternative Cost Analysis ($)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Expressed in 2020 dollars, unescalated -- dollars										
Capital Outlays										
BUS 400 scfm	12,000,000									
SCR										
HSW Receiving Facility										
Small Dig Improvements										
Total capital outlays	**12,000,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:										
D3 RINs	1,663,550	1,646,400	1,629,250	1,612,100	1,594,950	1,577,800	1,560,650	1,543,500	1,526,350	1,509,200
Power Savings	913,929	949,046	984,162	1,019,279	1,054,396	1,089,512	1,124,629	1,159,746	1,194,862	1,229,979
LCFS	852,234	858,555	864,561	870,252	875,621	880,683	885,430	889,862	893,973	897,776
Natural Gas Sale	392,447	399,475	406,503	413,531	420,559	427,587	434,616	441,644	448,672	455,700
HSW Tipping Fee										
Total benefits	**(3,822,160)**	**(3,853,476)**	**(3,884,476)**	**(3,915,162)**	**(3,945,526)**	**(3,975,583)**	**(4,005,325)**	**(4,034,752)**	**(4,063,857)**	**(4,092,655)**
Annual Running Costs:										
Engine O&M	184,893	191,997	199,102	206,206	213,310	220,415	227,519	234,623	241,728	248,832
BUS Labor	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000
Biogas/GCS Upgrading O&M	156,406	156,406	156,406	156,406	156,406	156,406	156,406	156,406	156,406	156,406
Natural Gas Purchased - Dig Heat	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	186,836	186,837	186,838	186,839	186,840	186,841	186,842	186,843	186,844	186,845
BUS Power	239,217	243,501	247,785	252,069	256,353	260,637	264,921	269,205	273,489	277,773
Total running costs	**892,352**	**903,741**	**915,131**	**926,520**	**937,909**	**949,298**	**960,688**	**972,077**	**983,466**	**994,855**
Net Benefit/(cost)	**9,070,192**	**(2,949,734)**	**(2,969,346)**	**(2,988,643)**	**(3,007,617)**	**(3,026,284)**	**(3,044,637)**	**(3,062,675)**	**(3,080,391)**	**(3,097,799)**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Expressed in escalated dollars with sensitivity adjustments										
Capital Outlays										
BUS 400 scfm	12,000,000	0	0	0	0	0	0	0	0	0
SCR	0	0	0	0	0	0	0	0	0	0
Small Dig Improvements	0	0	0	0	0	0	0	0	0	0
Total capital outlays (Pvs)	**12,000,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Benefits:										
D3 RINs	1,663,550	1,679,328	1,695,072	1,710,773	1,726,425	1,742,019	1,757,545	1,772,996	1,788,362	1,803,634
Power Savings	913,929	968,026	1,023,922	1,081,667	1,141,312	1,202,910	1,266,515	1,332,183	1,399,972	1,469,939
LCFS	852,234	875,726	899,489	923,518	947,800	972,345	997,138	1,022,172	1,047,432	1,072,925
Natural Gas Sale	392,447	407,465	422,926	438,843	455,227	472,091	489,448	507,310	525,690	544,603
HSW Tipping Fee	0	0	0	0	0	0	0	0	0	0
Total benefits	**(3,822,160)**	**(3,930,545)**	**(4,041,409)**	**(4,154,802)**	**(4,270,764)**	**(4,389,365)**	**(4,510,646)**	**(4,634,661)**	**(4,761,456)**	**(4,891,101)**
Discounted Benefits (in 2020$)	**(3,822,160)**	**(3,834,678)**	**(3,846,671)**	**(3,858,146)**	**(3,869,102)**	**(3,879,559)**	**(3,889,516)**	**(3,898,980)**	**(3,907,949)**	**(3,916,444)**
Annual Running Costs:										
Engine O&M	184,893	195,837	207,145	218,827	230,894	243,356	256,223	269,508	283,222	297,377
BUS Labor	125,000	127,500	130,050	132,651	135,304	138,010	140,770	143,586	146,457	149,387
Biogas/GCS Upgrading O&M	156,406	159,534	162,724	165,979	169,299	172,684	176,138	179,661	183,254	186,919
Natural Gas Purchased - Dig Heat	0	0	0	0	0	0	0	0	0	0
Natural Gas Purchased - Dryer	186,836	190,574	194,386	198,275	202,242	206,288	210,415	214,624	218,918	223,297
BUS Power	239,217	248,371	257,796	267,498	277,485	287,764	298,344	309,232	320,436	331,964
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
Total running costs	**892,352**	**921,816**	**952,102**	**983,230**	**1,015,223**	**1,048,102**	**1,081,890**	**1,116,611**	**1,152,287**	**1,188,944**
Discounted Running Costs (in 2020$)	**892,352**	**899,333**	**906,224**	**913,027**	**919,742**	**926,370**	**932,911**	**939,366**	**945,736**	**952,021**
		0								
Net escalated benefit/(cost)	**9,070,192**	**(3,008,729)**	**(3,089,307)**	**(3,171,571)**	**(3,255,541)**	**(3,341,262)**	**(3,428,756)**	**(3,518,051)**	**(3,609,169)**	**(3,702,157)**

Life cycle cost analysis	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PVs in 2020	9,070,192	(2,935,345)	(2,940,447)	(2,945,119)	(2,949,360)	(2,953,189)	(2,956,605)	(2,959,614)	(2,962,213)	(2,964,422)
Cumulative Benefits Payback	**9,070,192**	**6,134,846**	**3,194,399**	**249,280**	**(2,700,080)**	**(5,653,269)**	**(8,609,875)**	**(11,569,488)**	**(14,531,701)**	**(17,496,123)**
NPV as of 2020	**(17,496,123)**									