Prepared By:______________________
Dave Reardon

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Larry Smithey

____
Ryan Hougham

Reviewed By:______________________
Jeremy Holland

CITY OF SUNNYVALE

MASTER PLAN AND PRIMARY TREATMENT DESIGN

TECHNICAL MEMORANDUM

ELECTRICAL & COMBINED HEAT AND POWER PLAN:
MASTER PLAN

FINAL

September 2014

carollo in association with HDR

CITY OF SUNNYVALE

MASTER PLAN AND PRIMARY TREATMENT DESIGN

TECHNICAL MEMORANDUM

ELECTRICAL & COMBINED HEAT AND POWER PLAN: MASTER PLAN

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ELECTRICAL AND COMBINED HEAT AND POWER: MASTER PLAN

1.0 INTRODUCTION

The Sunnyvale Water Pollution Control Plant (WPCP) is undergoing a major upgrade that will include advanced wastewater treatment capability by 2023. When the new facility is operational, the plant power load will double and a new more reliable standby power arrangement will be needed as well as a new redundant power distribution system within the plant. The existing electrical infrastructure is not well suited to accommodate the increased loads and redundancy needed for the new plant. This technical memorandum describes the improvements needed for power generation, waste heat use, standby power, and power distribution. The electrical and combined heat and power plan proposed for the WPCP are based on providing the needed improvements through 2035 build out to meet the City's goals and objectives

The analysis and results of this Technical Memorandum are based on discussions among Carollo, HDR and the City. Our overall evaluation is based on the three step process starting with an internal Carollo/HDR workshop conducted on November 18, 2013, a preworkshop with limited City engineering and operations staff, and a workshop with the City on December 5, 2013 with the attendees listed in the workshop notes attached to this TM. Input was also obtained from City maintenance staff from a tour of two wastewater standby power facilities on January 8, 2014.

2.0 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

The conclusions and recommendations for the electrical and combined heat and power (ECHP) system are as follows.

2.1 Biogas Production

1. Provide for a Fats, Oils and Grease (FOG) receiving facility. FOG digestion can enhance biogas production.
2. Landfill gas is declining at approximately 2 percent per year.
3. A food waste receiving facility can be considered if the waste is preprocessed and in liquid form.
4. Split treatment, if used, is not expected to significantly impact biogas production.

2.2 Standby Power

1. Provide two diesel engine standby generators each with a capacity of 2000-2500 kW depending on the treatment process selected.

2. Locate the standby generators in separate walk-in enclosures. A building will be provided only for supporting electrical equipment.
3. Provide standby power for the Primary Treatment Project and expand later.
4. At the December 5, 2013 workshop the pros/cons and cost estimate were assembled and presented.

2.3 Power Supply and Distribution

1. Replace the existing distribution system with a 12.4 kV looped system.
2. Provide a secondary distribution using a secondary selective system.

2.4 Combined Heat and Power (CHP) and Heat Recovery

1. Because microturbine systems in this size range lack more than a few installations, if CHP design begins within the next 1-4 years, internal combustion engines are the recommended technology due to many years of operating history. After 2018, if microturbines have shown a proven performance record using biogas, then they should be considered as an option to internal combustion engines.
2. Provide a CHP facility with a capacity of 1700-2100 kW at the existing PGF location. This will provide CHP capacity until 2035. Two engines will be installed initially in the existing PGF building.
3. Provide capability of using natural gas to augment biogas.
4. Use waste heat from the CHP to heat digesters, administration building and maintenance building, and to provide biosolids drying capability.
5. Immediately provide updated controls and exhaust heat recovery for the existing power generation facility (PGF). A backup boiler is not recommended now but could be added later in the third bay of the PGF building.

3.0 STRATEGIC INFRASTRUCTURE PLAN (SIP) RECOMMENDATIONS

The SIP and Master Plan recommendations are compared in Table 1.

Table 1 Comparison of Master Plan and SIP recommendations for ECHP
Master Plan And Primary Treatment Design
City of Sunnyvale

Process / Technology	Strategic Infrastructure Plan (2011)	Master Plan (2014)
Biogas Production	• 2- 50,000 gallon gas storage tanks	• Provide for a Fats, Oils and Grease (FOG) receiving facility. FOG digestion can enhance biogas production. • A food waste receiving facility can be considered if the waste

Table 1 Comparison of Master Plan and SIP recommendations for ECHP Master Plan And Primary Treatment Design City of Sunnyvale		
Process / Technology	**Strategic Infrastructure Plan (2011)**	**Master Plan (2014)**
		is preprocessed and in liquid form. • No gas storage recommended because the economics are unfavorable.
Standby Power	• Upgrade the standby power system. Size: 2 MW. The new system should have a larger diesel fueled engine-driven generator, sized to meet the foreseeable needs of the WPCP. Unit can be stand-alone, as is the case now, or can be connected to operate in parallel with the cogen units.	• Provide diesel engine standby power with a capacity of 2.5 MW depending on the treatment process selected. • Locate the generators in separate enclosures (not a building) to optimize cost. • Provide standby power for the Primary Treatment Project and expand later. • Generators shall operate in stand-alone mode.
Power Supply and Distribution	• Develop a schedule for replacement of equipment identified to be too deficient or difficult to maintain. • Equipment 30 years old or more should be scheduled for replacement. • Install tie circuit breaker to split the bus on the main 4.16kV switchgear, to serve an upgraded 4.16kV primary distribution system. Rather than modify the existing switchgear, another switchgear may be installed nearby to serve as a Standby Power Bus or as a complete replacement. • Upgrade the primary electrical distribution system to allow quick restoration of power for 4.16kV cable failure. A primary selective system is	• Replace the existing distribution system with a 12.4 kV looped system. • Provide a secondary distribution using a secondary selective system. • All electrical equipment located outdoors will be weather protected. MCC's, transformers, motors and other electrical equipment will be located above the maximum flood elevation or protected from the maximum flood elevation. Climate change and sea level rise will be considered in locating electrical equipment.

Table 1 Comparison of Master Plan and SIP recommendations for ECHP
Master Plan And Primary Treatment Design
City of Sunnyvale

Process / Technology	Strategic Infrastructure Plan (2011)	Master Plan (2014)
	recommended. • Continue a program of scheduled maintenance for electrical equipment. • Implement a program to repair enclosures of electrical equipment where equipment is primarily failing due to corrosion. Repair corrosion, paint or coat with other material. • Consider implementing measures to protect outdoor electrical equipment from rain and other sources of water such as irrigation sprinklers. • New electrical equipment should be located at an elevation not subject to flooding. • Locate new electrical equipment indoors, in dedicated structure if necessary.	
Combined Heat and Power and Heat Recovery	• Replace engines with modern engines and a CHP system that is likely to meet future emissions requirements. • Provide gas treatment. Presumably this was intended to consist of H2S removal and siloxane removal.	• If CHP design begins within the next 1-4 years, internal combustion engines are the recommended technology due to many years of operating history. After 2018, if microturbines have shown a proven performance record using biogas, then they should be considered as an option to internal combustion engines. • Provide capability of using natural gas to augment biogas. • Use waste heat from the CHP to heat digesters,

Table 1 Comparison of Master Plan and SIP recommendations for ECHP Master Plan And Primary Treatment Design City of Sunnyvale		
Process / Technology	**Strategic Infrastructure Plan (2011)**	**Master Plan (2014)**
		administration building and maintenance building. • .Provide updated controls and exhaust heat recovery for the existing power generation facility (PGF)now. A backup boiler is not recommended now but could be added later in the third bay of the PGF building. • For the future CHP, provide gas treatment to remove hydrogen sulfide (iron sponge or sulfatreat media), moisture (glycol chilled heat exchanger and separator), and siloxane removal (activated carbon).

4.0 ENERGY BALANCE

4.1 Energy Balance

The Sunnyvale WPCP is in a unique position given that it is nearly 100% electricity neutral due to power generation in the Power Generation Facility (PGF). Plant operations has expressed a desire to investigate alternative options that decrease the purchase of natural gas now used in the PGF. While the WPCP may be very close to electricity neutral, energy neutral through the elimination of natural gas purchases would be the ultimate goal.

Figure 1 shows the current breakdown of the plant power supply. The plant does not have standby power capability now, but it must be provided for in the upcoming Primary Treatment project. The Primary Treatment project shall have loads that fall under the category of Critical Standby. The National Electric Code (NEC) classifies standby power under two categories; Critical Standby and Normal Standby. Plant loads have been estimated and are listed in Table 2 in the four major categories, as defined below.

- Critical Standby: Power system for Facilities that require continuous operation for the reasons of public safety, emergency management, national security, or business continuity.

- Normal Standby: Power system for facilities that require continuous operation to maintain the process for minimum treatment of influent.
- Estimated Peak Duty Load: Maximum electrical load that will operate to meet peak process demand.
- Estimated Connected Load: Sum of all electrical loads connected to the electrical system.

Standby power will be provided for “normal standby loads.” which includes the critical standby loads. The NEC allows for four types of standby power: Storage battery, generator, uninterruptible power supply (UPS), and fuel cell. The use of a cogeneration facility (with no backup) is not considered a reliable source of standby power.

The estimated plant loads for the year 2035 are summarized in Table 2. Total loads are delineated for the activated sludge and membrane bioreactor scenarios. The loads identified in Table 2 do not reflect possible future tertiary process additions of microfiltration, reverse osmosis, ultraviolet disinfection and centrifuge dewatering. The distribution system and standby power facility designs should consider the possibility of these future additions. Split treatment will reduce some of these loads initially. The final design should accommodate the loads in Table 2.

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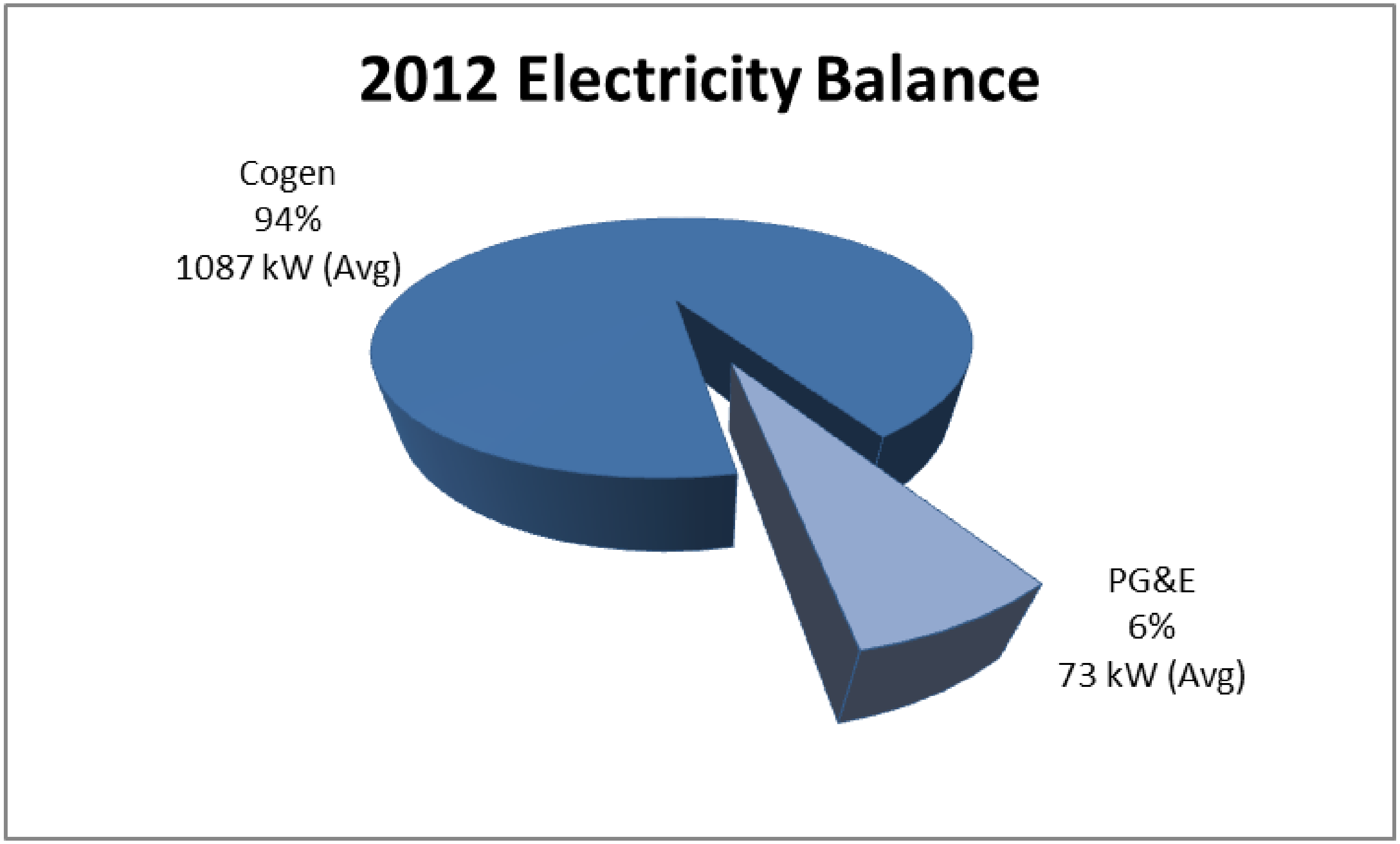


Figure 1
2011 / 2012 ENERGY BALANCE
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

Table 2 Summary of Future Plant Loads – 2035 (Horsepower)
Master Plan And Primary Treatment Design
City of Sunnyvale

Process	Critical Standby Load	Normal Standby Load	Est. Peak Duty Load (All Duty Units)	Est. Connected All Units (Duty & Standby)
Headworks	1,493	1,493	1,782	2,285
Primary Sedimentation	65	105	105	200
EQ Emergency Storage	0	0	60	90
Conventional Activated Sludge	0	758	1,673	2,070
MBR	0	1,793	3,168	3,593
Filtration	100	350	351	467
Disinfection	67	134	484	901
Recycled Water System	0	0	427	594
Thickening	25	89	187	282
Digestion	0	77	544	614
Dewatering	0	0	386	532
Support Facilities	50	101	201	251
Total for Activated Sludge (AS)	**1,800**	**3,107**	**6,200**	**8,286**
Total for Membrane Bioreactor (MBR)	**1,800**	**4,142**	**7,695**	**9,809**

4.2 Biogas Production from Landfill Gas and Anaerobic Digestion

The WPCP has two main sources of biogas (along with air blended natural gas [ABNG]) that provide a power source to the PGF: digester gas and landfill gas. The digester gas available to the plant in 2012/2013 was approximately 161,000 cubic feet per day (cfd), while the landfill gas available was approximately 384,000 cfd. Landfill gas is not as high quality as digester gas (415 BTU vs. 550 BTU), so the total blended biogas production now is 545,000 cfd at approximately 455 BTU.

Future biogas production (from biosolids digestion) is summarized in Table 3.

**Table 3 Future Biogas Production from Biosolids Digestion Only[1]
Master Plan And Primary Treatment Design
City of Sunnyvale**

Year	AAF or MMF	Cubic Feet Per Day (cfd)
2025	AAF	196,000
	MMF	237,000
2035	AAF	209,000
	MMF	254,000

Notes:
(1) Based on 13 cubic feet per pound VSS destroyed

Landfill gas is projected to degrade at an approximate rate of 2 percent per year (per the SCS AB32 Annual Report for the Sunnyvale Landfill dated March 2013) for the life of the landfill. The gas available at this rate for the next 20 years is presented in Figure 2. This depletion of the available biogas will have a significant impact on the cogeneration capabilities of the PGF. Therefore, alternate forms of fuel generation (such as FOG and food waste) will be investigated by the future gas optimization designer to mitigate the increased purchases of natural gas to make up the difference. These alternate forms can be expanded in the future as well to accommodate the decreasing performance of landfill gas

4.3 Biogas Production from Food Waste and Fats, Oils, and Grease (FOG)

The Kennedy Jenks Fats, Oils, and Grease Report (dated July 2012) identified the ability of area surrounding the WPCP to contribute up to 100 tons of FOG to a new receiving facility. This facility would serve as a revenue stream (from tipping fees), but long term would be a significant contributor to the PGF power capabilities. The total amount of gas available from a receiving facility would be approximately 54,000 cfd (assuming 13 cf per pound volatile solids destroyed).

While a FOG facility was identified as desirable, the window on the short-term payback profitability of such an investment may be shrinking. More and more agencies are constructing similar projects which are rapidly decreasing the supply of available FOG. Tipping fees, which currently are favorable, could decrease or disappear in the future. It is recommended that any FOG facility be built soon to take advantage of the current market.

The Kennedy report identified approximately 15 tons per day of food waste that can be received at the treatment plant. This amount of waste has the potential to produce approximately 75,000 cfd of biogas. Food waste that has not been preprocessed should not be considered for the WPCP due to operational challenges such as high labor requirements and odor potential. However, if the waste is prescreened and in liquid form, it can be considered a viable feedstock for the digesters. While the biogas quantities discussed within this document do not account for food waste, this alternative can be reevaluated by the future gas optimization designer.

4.4 Total Biogas Production

The total biogas available to the PGF in the future is summarized in Table 4 below.

Table 4 Total Biogas Production (cfd)
Master Plan And Primary Treatment Design
City of Sunnyvale

Year	AAF or MMF	Biosolids (550 BTU)	Landfill Gas (415 BTU)	FOG (550 BTU)	Total
2025	AAF	196,000	301,000	54,000	551,000
	MMF	237,000	301,000	54,000	592,000
2035	AAF	209,000	246,000	58,000	513,000
	MMF	254,000	246,000	58,000	558,000

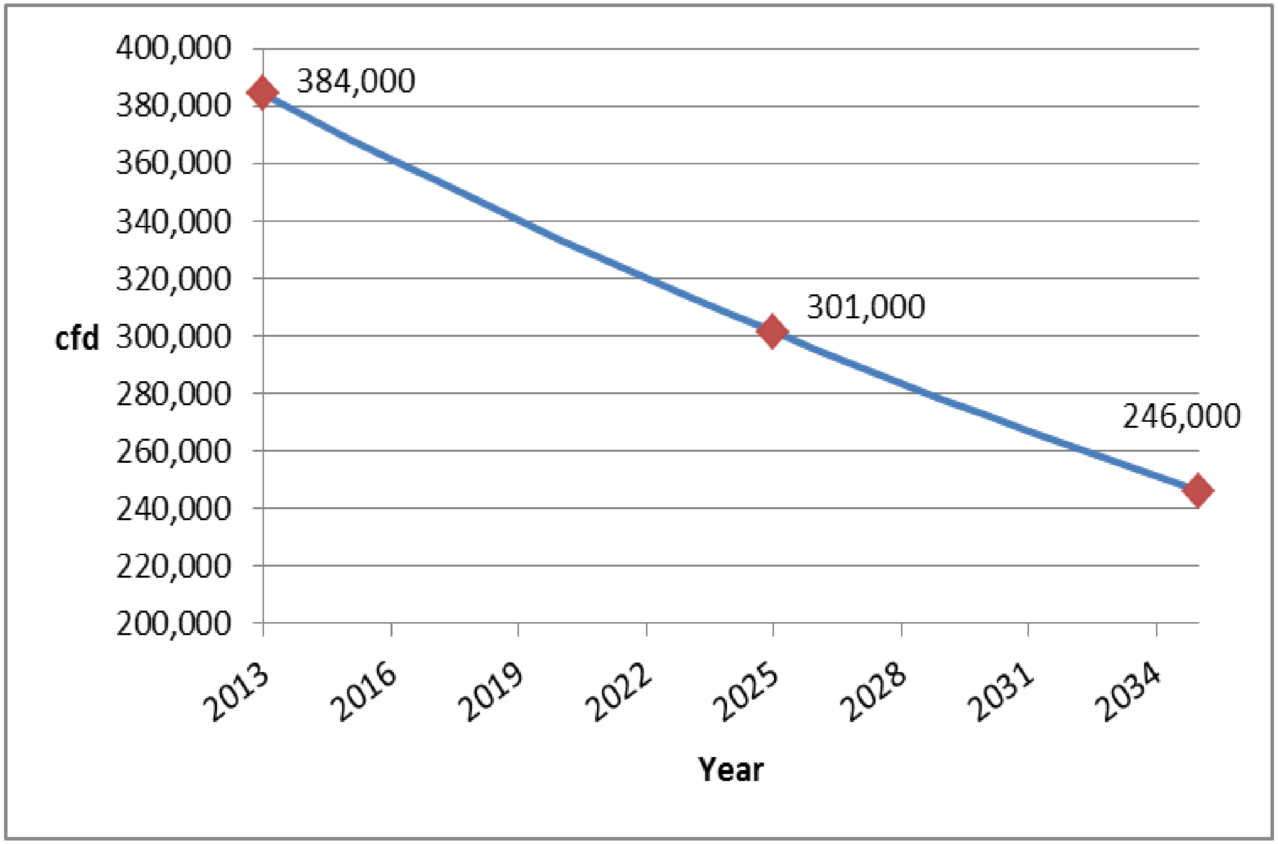


Figure 2
LANDFILL GAS DEGRADATION
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

For perspective, 525,000 cfd of biogas can generate approximately 1,300 kW at 38 percent electrical efficiency, while the plant will consume approximately 1,800 kW in the year 2025 (assuming activated sludge is installed for secondary treatment). If split flow treatment is implemented, overall waste activated sludge production will be reduced slightly. However, this small reduction in activated sludge will not significantly impact biogas production and CHP sizing. The CHP designer can consider this in the future.

Split treatment may have a minor impact on secondary biosolids generated. Moreover, biogas production from digestion of secondary biosolids is not anticipated to be nearly as significant as production from primary solids. Therefore, split treatment is not anticipated to significantly impact the biogas totals shown in Table 4.

4.5 Enhancing Biogas Production

A variety of options exist to enhance the existing plant biogas production, including the following:

- Improve primary sedimentation tank (PST) performance
- Waste Activated Sludge (WAS) pretreatment
- Thermophilic or Temperature Phased Anaerobic Digestion (TPAD)

These are discussed in further detail below.

4.5.1 PST Performance

Improving the performance of PSTs involves performing a computational fluid dynamics model (CFD) on the system and strategically locating new baffles for higher suspended solids removal. Such a system can possibly generate a 10-12 percent increase in said removal. It is estimated that the increase in biogas from implementing baffling would be approximately 11,000 cfd. If used, baffling will be included in the future primaries, not the existing tanks. Unfortunately, this is a negligible increase and not sufficient enough to impact the CHP sizing. Therefore, this potential increase in biogas is not included in Table 3. Evaluation of providing baffles for performance enhancement only will be covered in another TM.

4.5.2 Waste Activated Sludge (WAS) Pretreatment

A variety of pretreatment options exist for WAS, including mechanical or pressure related, electrical, chemical and ultrasound treatment, as well as thermal hydrolysis. Unfortunately these technologies are still in their infancy stages and need at least another five years to mature. Costs associated with increased energy and chemical costs typically are not offset by the value of increased biogas production. Piloting these potential technologies is highly recommended if such treatment is desired in the future.

4.5.3 Temperature Phased Anaerobic Digestion (TPAD) and Thermophilic Digestion

These technologies can increase volatile solids concentrations by approximately five (5) percentage points. The total increase in biogas production is approximately 10,000 cfd, which is not enough to justify heating the sludge to this high condition. This operational methodology should be considered in the future if Class A biosolids are needed. Currently there are no regulatory drivers to implement these technologies.

4.6 Summary and Recommendations

The WPCP consumes approximately 1,160 kW and is nearly electricity neutral. By 2025 the plant will consume approximately 1,800 kW if activated sludge is selected and have the biogas available to produce approximately 1,300 kW. Improvements to WAS pretreatment, and thermophilic enhancements are not viable options at this time. Primary sedimentation tanks (PST), improvements should be considered for non-biogas related performance enhancement (evaluated in a separate TM). The recommendations to enhance the energy balance of the WPCP are:

- Design and build a FOG receiving facility as early as possible in order to take advantage of current market economics
- Reevaluate WAS pretreatment in five years
- Reevaluate thermophilic digester operation in the event Class A biosolids are required
- PST baffles can be evaluated in the future to determine if solids capture (and thus biogas production) can be enhanced. Current implementation of baffles for performance optimization only should be considered.

5.0 STANDBY POWER

5.1 Background

The only standby power at the WPCP is a 80 kW engine driven generator. It is used to provide power for auxiliary systems for the PSTs and allows the influent pump engines and related equipment to be operational during power outages. The standby generator can also be used to start the PGF facility after a power outage occurs. However the generator does not have capability to provide power to the start the PGF facility and support the influent pump engines and their support equipment simultaneously.

The PGF has been used to provide plant power during power outages. However, as previously stated, it is unreliable and not capable of bringing on significant block loads. Also, use of a cogeneration facility (with no backup) is not considered as a reliable source of standby power. For these reasons, the plant will need separate diesel powered standby power. The facility must be able to start and power the plant from “black start” conditions. The facility will be sized for “normal standby conditions” which is defined as a capacity to continuously operate the plant to maintain the process for a minimum treatment of effluent.

5.2 NEC and EPA Reliability Criteria

The standby power is classified in two separate categories by the National Electric Code (NEC). First is “Critical Operations Power System (COPS)” which is defined by the NEC as follows: “Power systems for facilities or parts of facilities that require continuous operation for the reasons or public safety, emergency management, national security, or business continuity.”

The other category is equipment that is necessary to maintain operation of the process plant. The owner of the facility determines what is necessary to maintain the operation. Areas such as the Administration Building and Maintenance Building are not critical to the process and will not require a dual electrical feed.

The standby power generation requirements for COPS are defined in Article 708 of the NEC. There are four types of standby power:

- Storage battery
- Generator set
- Uninterruptible power supply (UPS)
- Fuel cell system

Storage batteries, UPS, and fuel cell systems do not come in the sizes required by this project. The source of the standby power is required to be one of these types (NEC 708.20) with diesel generators being the only practical type for this installation. The duration of COPS operation is defined as 72 hours at full load.

The reliability criteria are based on the EPA Publication “Design Criteria for Mechanical, Electrical and Fluid System and Component Reliability”. The major item of these criteria is that no single equipment failure can cause 50 percent of the process to fail. This results in design criteria for a redundant electrical system. Examples of the criteria are:

- Dual path for primary voltage conductors
- Dual transformers for major process areas
- Double-ended switchgear
- Separate 480volt motor control centers (MCC’s) in each facility. The plant load would be divided between the separate MCC’s.

All of these should be included in the upcoming WPCP upgrades.

5.3 Alternatives Discussion

Two alternatives for providing standby power to the WPCP are:

- Option 1 – On-site power generation
- Option 2 – Dual electrical feed from PG&E.

The summary of the future plant loads were summarized in Table 2 in Section 4.1. The sizing of the standby units below is based on not having split flow treatment. If split flow treatment is implemented, then generator sizing may be reduced.

Option 1 – Option 1 would consist of diesel generators connected electrically to the service switchgear thru 12 kV circuit breakers. The schematic for this operation is represented in Figure 3. Upon loss of power, the generators would start within a short amount of time and the plant would be brought on-line through operation of the 12 kV circuit breakers by the generator control panel which would contain a programmable logic controller. The process equipment would then be brought on line through a predetermined sequence by the SCADA system. The cogeneration system would be taken off line during the power outage. The process would be fully automatic and not require manual operation.

The incoming 12 kV line would be monitored by the generator control panel. When power is restored and after a set point amount of time (the amount would be long enough, minimum 15 minutes to insure that PG&E power is stable) the power would be transferred back to PG&E thru operation of the 12 kV circuit breakers. One operational option is that the transfer back is initiated by operation's staff versus it being done automatically. The purpose of this is to insure that PG&E power is stable and that the plant comes back on line under supervision.

The number and size of the generators will be dependent on the treatment process chosen and the size of the equipment required for the process. The switchgear would have a load bank for load balancing and for exercising the generators. The generators would be provided and operated to meet the air board current standards at time of installation. The stand by generators will be per the "Normal Standby Load" column in Table 2. The generators should be designed to have an additional 20% capacity for future additions which are undefined at this time. Split flow will reduce the initial sizing of the secondary facilities but all key electrical and CHP infrastructure will be designed to account for ponds being discontinued ultimately. The estimated sizes of the generators are as follows:

<u>Conventional Activated Sludge:</u>

Total from Table 2 is	3107 HP
Additional 20% for future additional load requirements	620 HP
Total	3727 HP

The generators would be sized at 2 units @ 2000 KW

MBR:

Total from Table 2 is	4142 HP
Additional 20% for future additional load requirements	800 HP
Total	4942 HP

The generators would be sized at 2 units @ 2500 KW

Option 2 – Option 2 consists of changing the electrical service from one PG&E service point to two, independent service points. The schematic for this operation is represented in Figure 4. The existing service includes a 4.16 kV switchgear and is derived at a PG&E pad mounted switch located in front of the existing influent pump station. The switch is fed from the PG&E 12 kV feeder from the distribution system. If there is a problem with the switch or feeder the facility loses electrical power.

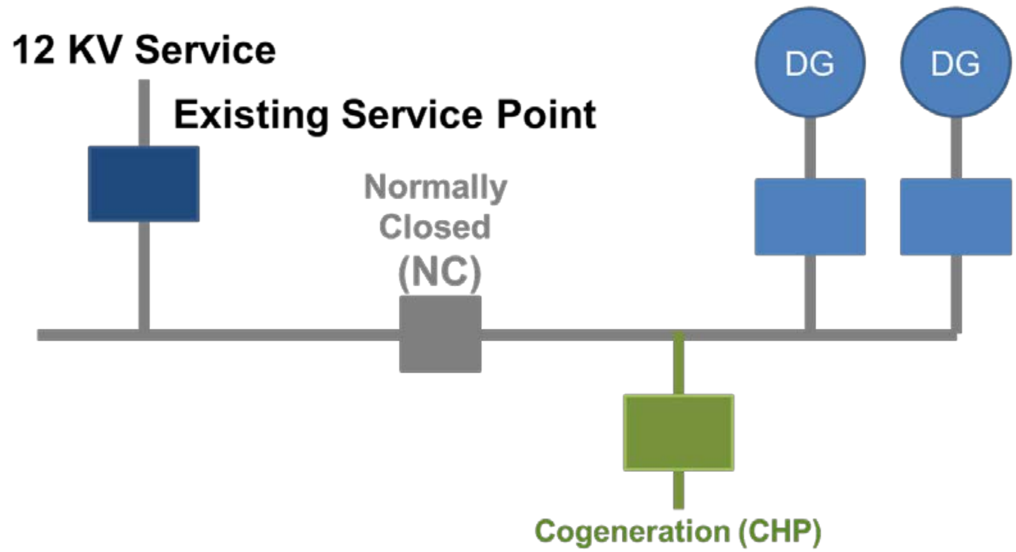
A second independent service would have to have the following conditions met to be considered independent from the first service:

- Consist of a feeder derived from a different substation than the first feeder. Outage records would be reviewed to determine if the substations have lost power at the same time.
- The feeder would have to be physically separated from the first feeder. I.e., the conductors of both feeders could not be located in the same manhole.
- Power capacity would be available at all times on both feeders. If one feeder failed, the other feeder could automatically provide all power for the facility. Control of which feeder was providing power would be by the facility and not PG&E.

The feeders would be sized to have capacity to operate the complete facility. PG&E would size the feeders, proposed but the estimated size is 600 amps at 12.47 kV. Each feeder would be terminated in the main plant switchgear facility. The switchgear would be double ended with automatic tie circuit breakers. Upon power failure of one feeder the switchgear control panel would control the circuit breakers such that the failed feeder, would be isolated from the switchgear and the other feeder would be providing power to the complete plant.

Option 2 would require up front fees to PG&E to determine if a second independent feeder is feasible, which includes preparing a load study of the PG&E system to determine if capacity for the second feeder is available. Two feeds would also result in a large capacity charge fee (regardless of whether the feeds are used). In addition, the second independent feeder does not meet the NEC, Article 708 requirements for stand by power for a Critical Operations Power System (COPS).

Option 1: Diesel Generators (DG)



Number and size of generators to be determined by process load

- **2- 2,000 kW for Conv. Activated Sludge**
- **2- 2,500 kW for MBR**

Figure 3
OPTION 1: DIESEL GENERATOR SCHEMATIC
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

Option 2: Two Independent 12 kV Electrical Services From PG&E

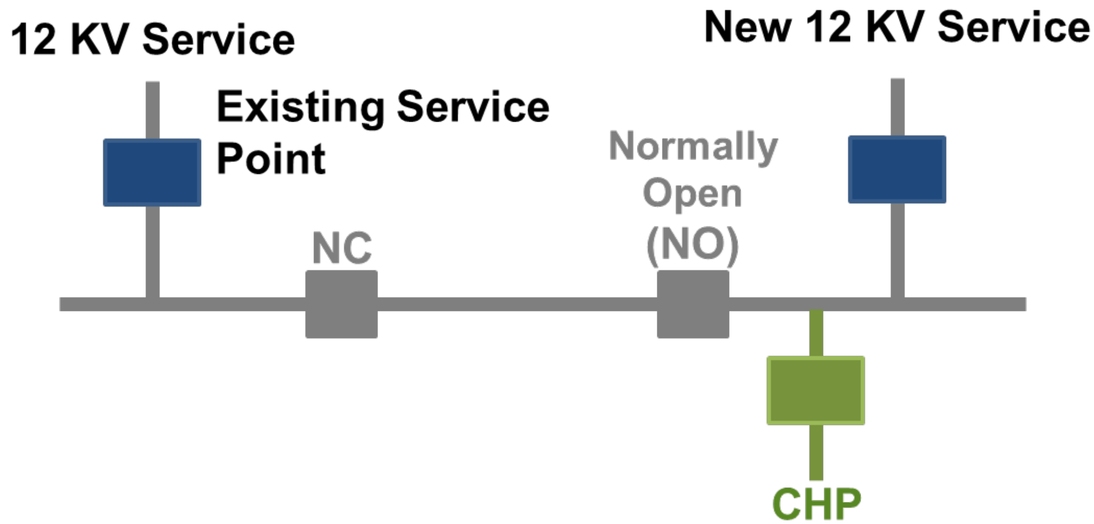


Figure 4
OPTION 2: DUAL 12 KV FEEDS SCHEMATIC
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

5.4 Recommendations

Because Option 2 does not meet the COPS requirements for standby power, diesel standby power (Option1) is recommended.

5.5 Alternatives Layouts

There are two options for providing Diesel Standby generation: (1) install generators in a building or (2) install generators in walk-in weatherproof enclosures. Descriptions of the alternatives are described below.

5.5.1 Option 1, Alternative Layout 1

This layout is depicted in Figure 5. This figure is an example of similar application in Sacramento. The generators would be installed in a building with the 12 kV switchgear in an adjacent room. The building would be built with sound attenuation for the exhaust and intake. The generators have a sound rating of 70 dB at 23 feet. The building would include a bridge crane for maintenance and moving equipment. The approximate size of the building is 130 feet long and 60 feet wide. The generator load bank would be located outside near the switchgear and be sized to exercise one generator at 50% load. The fuel tanks would be sized to provide 72 hour capacity for critical loads and 24 hour capacity for normal stand by loads. The stand by load for critical loads is 1598 kVAwhich would require one generator to operate at 75 percent load for 72 hours which would result in requiring 7632 gallons. The normal standby load for conventional activated sludge is 1409 kVA which would require 75 percent load for 24 hours which would require 2544 gallons. The fuel would be stored in two 5000 gallon above ground storage tanks outside the building for the conventional activated sludge options. For the MBR, normal stand by load is 2554 kVA which would require 100 percent load for 24 hours which result in requiring 4263 gallons and critical loads would be the same size. The fuel would be stored in two, 6000 gallons above ground storage tanks outside the building for the conventional activated sludge options. The fuel would be pumped into day tanks adjacent to the generator.

5.5.2 Option 1, Alternative Layout 2

This layout is depicted in Figure 6. The generators would be installed in line outside in outdoor walk-in weatherproof enclosures. The switchgear will be housed in a switchgear building adjacent to the generator area. The enclosures would be purchased as part of the generator package and be furnished with the generator. The generators enclosure would have enough room to walk around the generator and perform maintenance. The generators can be removed by crane through the louvers, or smaller pieces can be removed through the roll-up door. The generator enclosures will be customized to allow installation of hoisting equipment as well as provide additional room for maintenance. The enclosure would have sound attenuation equipment and baffles on the intake and on the exhaust. The sound rating would be 70 dB at 23 feet. The approximate size of the area is 105 by 60 feet. The fuel requirements will be the same as Alternative 2.

5.5.3 Option 2 Layout

Option 2 was eliminated in Section 5.3 and not considered further.

5.6 Cost Summary

The following construction cost summary in Table 5 is for the conventional activated sludge option.

Table 5 Standby Power Costs (Activated Sludge)
Master Plan And Primary Treatment Design
City of Sunnyvale

Component	Conventional Building	Outdoor (walk-in enclosure)
Generator Building 2,700 sf @ $450/sq ft	$1,215,000 +/-	---
Outdoor Generator Pad & Enclosure 2 ea @ $275,000	-----	$550,000 +/-
Switch Gear Building 1500 sq ft @ $200/sq ft	$300,000 +/-	$300,000 +/-
Generator Cost (2000 kW ea) 2 ea @ $800,000	$1,600,000 +/-	$1,600,000 +/-
Switch Gear Cost	$1,200,000 +/-	$1,200,000 +/-
Fuel Storage (2 @ $100,000)	$200,000 +/-	$200,000 +/-
Site Work	$220,000 +/-	$220,000 +/-
Total	**$4,735,000 +/-**	**$4,070,000 +/-**

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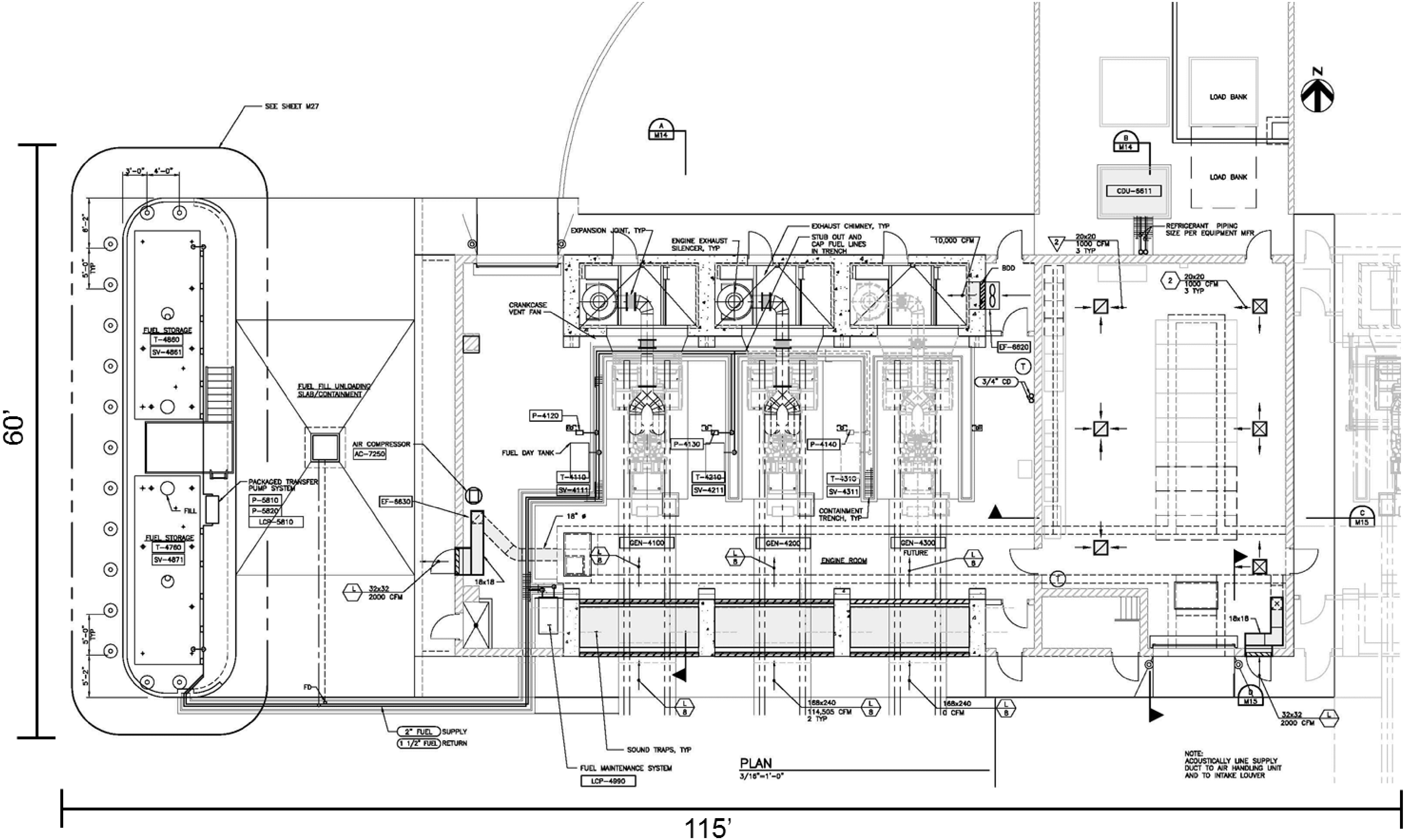

Figure 5
OPTION 1 ALTERNATIVE LAYOUT A (GENERATOR BUILDING EXAMPLE)
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

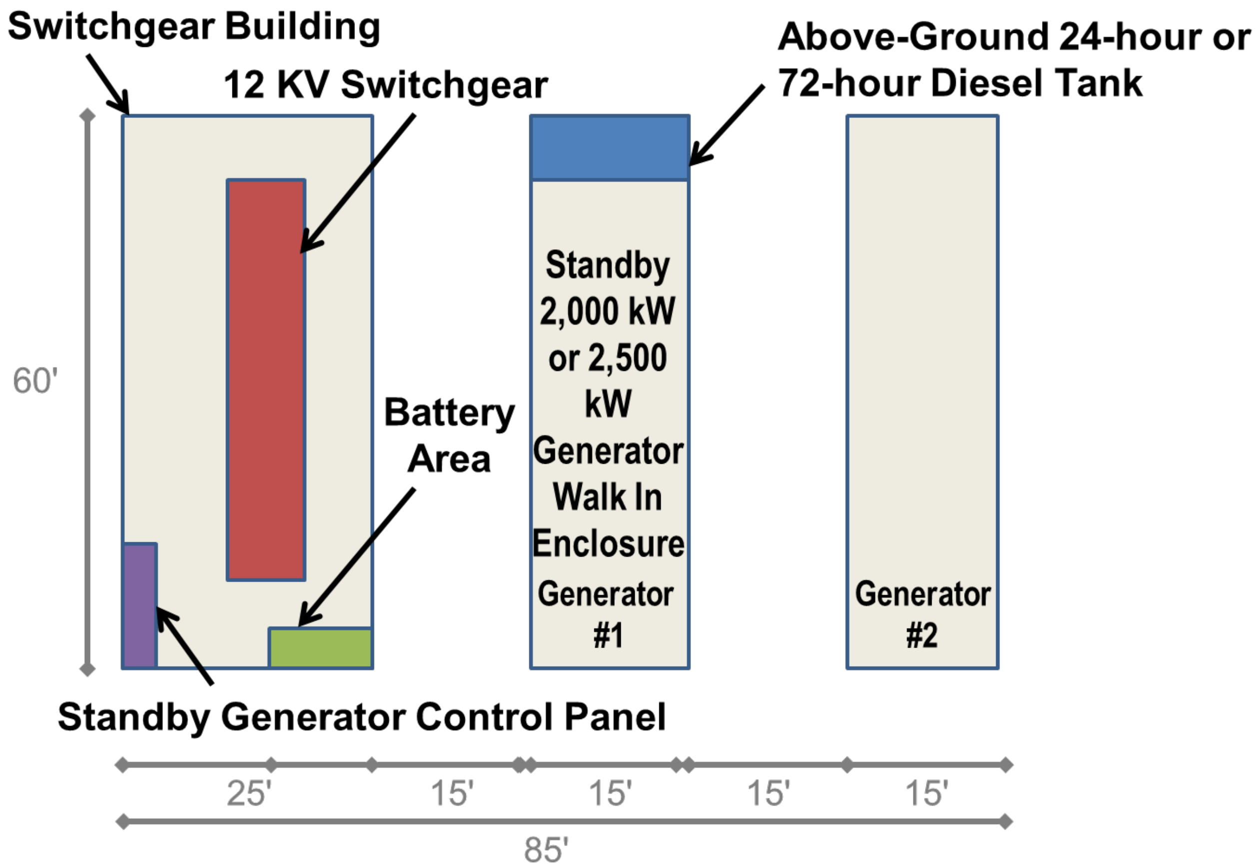

Figure 6
OPTION 1 ALTERNATIVE LAYOUT B
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

5.7 Advantages and Disadvantages

The advantages and disadvantages are summarized in the Table 6 below for Option 1, Alternative 1 and Option 1, Alterative 2.

The reliability for both alternatives is equal, as there are no differences in electrical configuration and both alternatives protect the generators.

- The capital cost for the conventional building (Alt 1) is larger than for the outdoor walk-in enclosures (Alt 2). The building cost is the largest factor between the two alternatives.
- Alt 1 has a large advantage over Alt 2 in ease of maintenance. The building has more space around the generators to perform maintenance and has a bridge crane for moving heavy equipment. The walk in enclosures have the minimum space required and would be not as efficient to perform maintenance as the building.
- Operating cost is equivalent for each alternative.
- The building allows for easier access and areas to store equipment around the generators while performing maintenance. This can be mitigated in the outdoor enclosure by making them larger than the minimum clearances required.
- Site Efficiency is equivalent for each alternative.
- Design cost for Alt 1 is larger due to having to design a building.
- Construction phasing is equivalent for each alternative.

Table 6 Comparison of Standby Power Enclosure Alternatives
Master Plan And Primary Treatment Design
City of Sunnyvale

	Conventional Building	Outdoor (walk-in enclosure)
Reliability	+	+
Capital Cost	–	+
Ease of Operation/Maintenance	+	0
Operating Cost	0	0
Site Efficiency	+	+

Table 6	Comparison of Standby Power Enclosure Alternatives Master Plan And Primary Treatment Design City of Sunnyvale	
	Conventional Building	**Outdoor (walk-in enclosure)**
Design Cost	–	+
Construction Phasing	0	+

Notes:
(1) Legend: + Better; 0 Neutral; - Worse

5.8 Summary and Recommendation for Generator Installation

It is recommended to locate two generators in separate outdoor walk-in enclosures. A building will be provided only for supporting electrical equipment. The two generators will be sized for loads expected up until 2035. A third generator could be added later if further plant modifications are made. The sizes of the generators will be either 2000 kW or 2500 kW each depending on the process treatment selected.

The proposed sequence for construction is as follows:

- Install the first generator, 12KV switchgear and Generator Control System (GCS) under the Primary Treatment Facility project.
- The GCS includes the capability to monitor utility and generator power, open and close 12 kV circuit breakers, and synchronize and control multiple generators.
- Install the second generator under the Secondary Treatment Facility.

5.9 Transition to New Service

The existing distribution service will initially stay in place. When the new 12 kV feeder and switchgear are installed, the existing service will be taken out of service as PG&E usually allows only one service to a facility. In addition, standby power will be provided to the existing plant. The proposed transition is as follows:

- Initially existing switchgear and distribution stays in place
- The Primary Treatment Design Project installs new PG&E 12 kV feeder, switchgear and stand by generators

- As part of the project, the existing PG&E feeder is removed along with the PG&E 12kv/4.16kv transformer.

- A feeder from the new 12 kV switchgear and 12kV/4.16kV transformer will be installed along with a feeder in-between the 12 kV switchgear, 12 kV/4.16 kV transformer and the existing 4.16 kV switchgear. Using this configuration, the standby generators can supply standby power to the existing plant. The existing cogeneration system will continue to be connected to the existing 4.16 kV switchgear. The correct relay protection will be installed in the new 12kV switchgear per PG&E requirements for the current cogeneration system and the future new cogeneration system.

- As future projects take existing facilities off line, the existing 4160/480 volt equipment will be removed. All existing electrical equipment will eventually be replaced with new electrical equipment.

- New facilities in the area of the existing plant will be fed from a new 12 kV distribution system with new transformers to step it down to 480 volt.

- Eventually, the 4.160 kV system will be removed including the existing 4.16 kV switchgear.

5.10 Black Start and Island Mode Operation

The plant's existing black start and island mode operational capabilities are as follows:

- Resumption of operations after power failure

- Disconnect cogeneration system from PG&E system

- Stand by generator starts (supports influent pumps (engine driven) or cogeneration system)

- Cogeneration system can be operated manually but is not connected to PG&E system.

- Upon return of power, plant is brought back online using an "open" transition operation (i.e. all equipment is shut down and then turn on after power from PG&E is restored).

The proposed black start and island mode operational capabilities (phased in as part of the headworks project due to influent pumps needing backup power) would involve the following"

- Resumption of operations after power failure

- Disconnect cogeneration from PG&E system

- Generators start automatically within 30 to 60 seconds. First generator on line will act as a frequency synchronization source for the second generator.

- Disconnect cogeneration system from PG&E and plant system.
- 12 kv circuit breakers open isolating switchgear from PG&E and load.
- 48 VDC battery bank at 12 kv switchgear provides power for power circuit breakers and generator control system.
- Generator Control System brings generators on-line after generators are up to speed and ready.
- Generator Control System (GCS) closes 12 kv load circuit breakers in sequence to energize transformers and switchgears.
- Process Control System (PCS) will bring process systems on line in a predefined sequence. The PCS will communicate with the GCS and monitored status and loading of generators. If a problem arises with one of the generators, the PCS will perform load shedding to maintain the correct load on the remaining generator.
- Process will not start "all at once" – large loads will be started in steps.
- While operating on standby power, the cogeneration system may be used to augment the diesel generators. Use of the cogeneration facilities will be a manual operation.
- Upon return of power, the plant is brought back online using a "closed transition" function. The GCS will synchronize the generators and the PG&E system and connect the load in phase. The GCS will open and close circuit breakers to perform this function. There will be three optional modes for performing this operation:
  - Full automatic – After a set point amount of time, the GCS will initiate a transfer back to PG&E power. The amount of time will be entered by the operator but will be a minimum of 15 minutes. The delay is to allow the PG&E system to return to stable operation.
  - Manual initiate – In this mode, the GCS will not transfer back to PG&E until the operator manually initiates (thru the OIT at the GCS) the transfer. The GCS will perform all operations.
  - Manual transfer – In this mode, the operator will operate all circuit breakers and transfer the system back to PG&E. It is expected that this mode will be done in a "open transition", that is the plant will be shut down before the transfer. This allows the generators to be taken off line and the PG&E system to be brought on line manually.

6.0 ELECTRICAL DISTRIBUTION

6.1 Background

The existing WPCP receives power from PG&E at a service voltage of 4.16 kV through a City owned transformer with a nameplate capacity of 2500 kVA. The original 5 kV switchgear appears to have been installed in 1970 and upgraded since then. The switchgear has six feeder circuits that distribute 4.16 kV service to the plant using simple radial feeds with no redundancy. The exception to this simple radial system is a 4.16 kV loop that serves two load centers at the ponds. Each load center has a primary selector switch to select either side of the loop. Step down transformers at load centers in the plant reduce voltage from 4.16 kV to 480 volts. This 480 volt power is distributed to the various electrical equipment including switchgear, switchboards, MCCs, and panel boards.

The electrical cogeneration system is connected to the 4.16 kV switchgear from a smaller (2,000A) switchgear located at the cogeneration building. The feeder is underground in a duct bank. The stand by generator is sized at 80 kW and is connected to MCC P thru a transfer switch. It feeds Lighting Panel A and MCC F which provides power in the Primary Control Building. Conduit and conductors are in place to feed from MCC P to MCC’s B and D. The circuit breaker at MCC P (400 A) for this feeder is currently open.

The Strategic Infrastructure Plan (SIP) included an inspection and condition assessment of electrical equipment at the plant. The equipment was described as well maintained and in generally good condition despite its age (over 30 years). Much of the equipment is now obsolete and parts are becoming more difficult to find. Because the electrical distribution system and equipment has reached is useful life, maintenance costs are increasing, and there is no distribution redundancy. Therefore, the City should consider replacing all electrical distribution components (primary and secondary) with a fully redundant system.

6.2 Existing Feed

The existing electrical feed is located at an outdoor 4.16 kV switchgear located in a weatherproof enclosure. The switchgear is rated at 4.16 kV, 2000 amp, 3 phase, 42 kaic. The primary side of the service is provided by PG&E. The switchgear is fed by a PG&E pad mounted 12 kV/4.16 kV transformer located adjacent to the switchgear. The transformer is fed underground from a pad mounted switch located in front of the influent pump station. In addition to the plant service, the switch feeds an overhead line outside of the plant towards the bay. The cogeneration system is connected to the switchgear and has relay protection which can disconnect the plant cogeneration system from the PG&E system, either automatically or by remote action from PG&E.

6.3 Distribution Alternatives

The planning considerations include determining voltage level, primary distribution configuration, secondary distribution configuration and construction phasing of the installation of the electrical distribution system. The loads identified in Table 2 do not reflect possible future tertiary process additions of microfiltration, reverse osmosis, and ultraviolet disinfection. The distribution system design should consider the possibility of these future additions. Two electrical distribution alternatives are evaluated below:

6.3.1 Primary Radial Distribution

The primary radial distribution system will consist of the following:

- The switchgear will be divided into an “A” side and an “B” side. Each side will be sized to carry the complete plant load.
- 12 kV circuit breaker in the main 12 kV switchgear, one on the “A” side and one on the “B” side.
- Dedicated underground 12 kV feeders directly to an area substation. The substation will have a 12 kV/480V transformer sized for the building load.
- Each area substation will have two dedicated 12 kV feeders, one from each side of the switchgear
- Feeders will be physically separated from each other for reliability. Ductbanks will have 5 feet separation but can be installed parallel. See Figures 9 and 10 for example locations and routing. Exact routing will have to be in coordinated with the existing and proposed process facilities.

6.3.2 Primary Loop Distribution

The primary loop distribution system will consist of the following:

- The switchgear will be divided into an “A” side and an “B” side. Each side will be sized to carry the complete plant load.
- 12 kV circuit breaker in the main 12 kV switchgear, one on the “A” side and one on the “B” side. Each circuit breaker will have the ability to serve the complete loop.
- Underground 12 kV feeders installed to an area substation in a loop configuration. The substation will have a 12 kV/480V transformer sized for the building load. The feeders will be connected to primary switches located at the substations which will allow the feeder to continue to the next substation. The feeder will continue on to the other side of the switchgear.

- Each area substation will have the ability to be fed from either direction from the loop, one from each side of the switchgear. The switches will be manually opened and closed using remote control to configure the system.

- Feeders will be physically separated for reliability. Each side of the loop will have a different physical path to substations. See Figures 11 and 12 for example locations and routing. Exact routing will have to be in coordination with the piping and facilities.

6.4 Voltage Recommendation

The current existing service is at 4.16kV. The proposed service voltage is 12 kV for the following reasons:

- PG&E distribution voltage is 12kV. A 4.16 kV service requires a transformer is required to be installed by PG&E to change the voltage from 12 kV to 4.16 kV. The estimated losses in this process is approximately 2% depending on the load on the transformer.

- 12 kV and 4.16 kV is technically equivalent

- 12 kV circuits can use smaller conductors for the same load

- 12 kV circuits can have a larger capacity resulting in less circuits being required.

The 12 kV distribution system is less expensive to construct and operate. Therefore, it is recommended.

6.5 Primary Radial System for Activated Sludge and MBR

The loads for Activated Sludge and the MBR process systems are of different sizes and configuration. But for the discussion of evaluating which electrical distribution system to choose they are considered equivalent. Split flow treatment (using the ponds) will reduce activated sludge and MBR electrical loads slightly in the near term, but the system should be designed assuming the ponds will be ultimately discontinued.

6.5.1 <u>Advantages and Disadvantages</u>

6.5.1.1 Radial System Advantages

- Quick restoration of service if a transformer or feeder fails. The transformers and feeders are separate from each other, therefore to isolate the failed piece of equipment the operator would open the circuit breaker in the main switchgear

- Substations are fed from two different sources

- The system can be built in phases, one feeder at a time as the facilities are constructed.

- Arrangement is very static, each transformer is fed by the same feeder with a dedicated circuit breaker in the switchgear. Simpler to train the operators of the system.

6.5.1.2 Radial System Disadvantages

- The amount of duct banks, conduits, and conductors is larger than the loop system. The amount of underground space is also larger. It is estimated that each duct bank will require 9 square feet of underground space. The underground space in the existing portion of the plant is very congested and finding underground routes for the duct banks will require additional effort.

- Longer conduit and conductors than Loop System.

6.5.1.3 Loop System Advantages

- The loop system is more reliable than the radial system. Each substation/transformer can be fed from two different feeders and 12 kV circuit breakers.

- Loop system is flexible as the loading on each 12 kV feeder can be changed by reconfiguring the switches at the substation. The substation/transformer connection can be moved from one 12 kV feeder to another.

- Lower cost due to lower amount of duct banks, conduits, and conductors compared to the radial system.

- If one side of the 12 kv switchgear fails, the plant can be fed from the other side by switching in the field on the primary side. The radial system would have to switched on the secondary side.

- Smaller footprint fro ductbanks (less than half of the footprint for a radial system).

6.5.1.4 Loop System Disadvantages

- Conductors are larger sizes than the radial system

- Loop system is more difficult to build in phases. Either the loop has to be built partially or provisions need to made to extend the loop for future facilities.

6.5.2 <u>Schematics</u>

Figure 7 shows a representation of a single line for the radial system, and Figure 8 a single line for the loop system

6.5.3 <u>Layouts</u>

Figures 9 and 10 shows a proposed ductbank layout for a radial system for Conventional Activated Sludge and MBR facilities, respectfully. Each line represents two parallel ductbanks with two transformers at each service location.

Figures 11 and 12 shows a proposed ductbank layout for loop system for Conventional Activated Sludge. Each line represents a ductbank with two transformers with primary switches at each service location and a single transformer at the Administration Building, respectively.

Primary circuit switches will be used to configure the systems.

6.5.4 Site Configuration Comparison

- The loop system is less expensive than the radial system. The amount of ductbanks is less resulting in a lower construction cost.
- Operating cost for each system is equivalent
- The loop system has less site/corridor issues at it takes less underground space than the radial system
- Safety is equivalent for each system.
- Reliability of each system is equivalent.
- The radial system is easier to build in phases than the loop system. The radial feeders can be built as each facility is brought on line.

The advantages and disadvantages are summarized in the Table 7.

Table 7 Comparison of Electrical Distribution Alternatives
Master Plan And Primary Treatment Design
City of Sunnyvale

	Radial	Loop
Capital Cost	-	+
Operating Cost	0	0
Site/Corridor Issues	0	0
Safety	0	0
Reliability	0	0
Phased Construction Considerations	+	-

Notes:
(1) Legend: + Better; 0 Neutral; - Worse

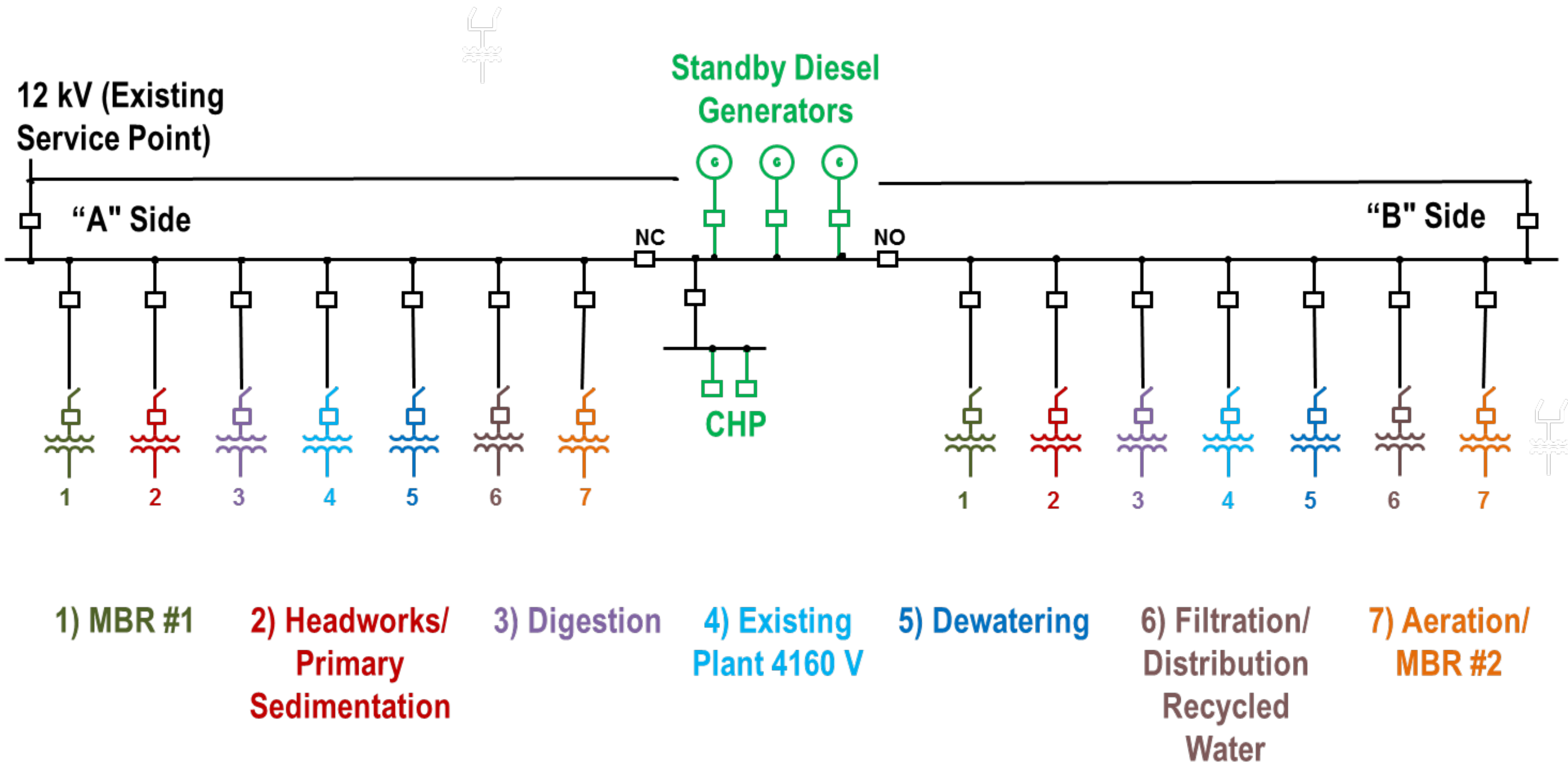

Figure 7
SINGLE LINE DIAGRAM FOR RADIAL SYSTEM
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

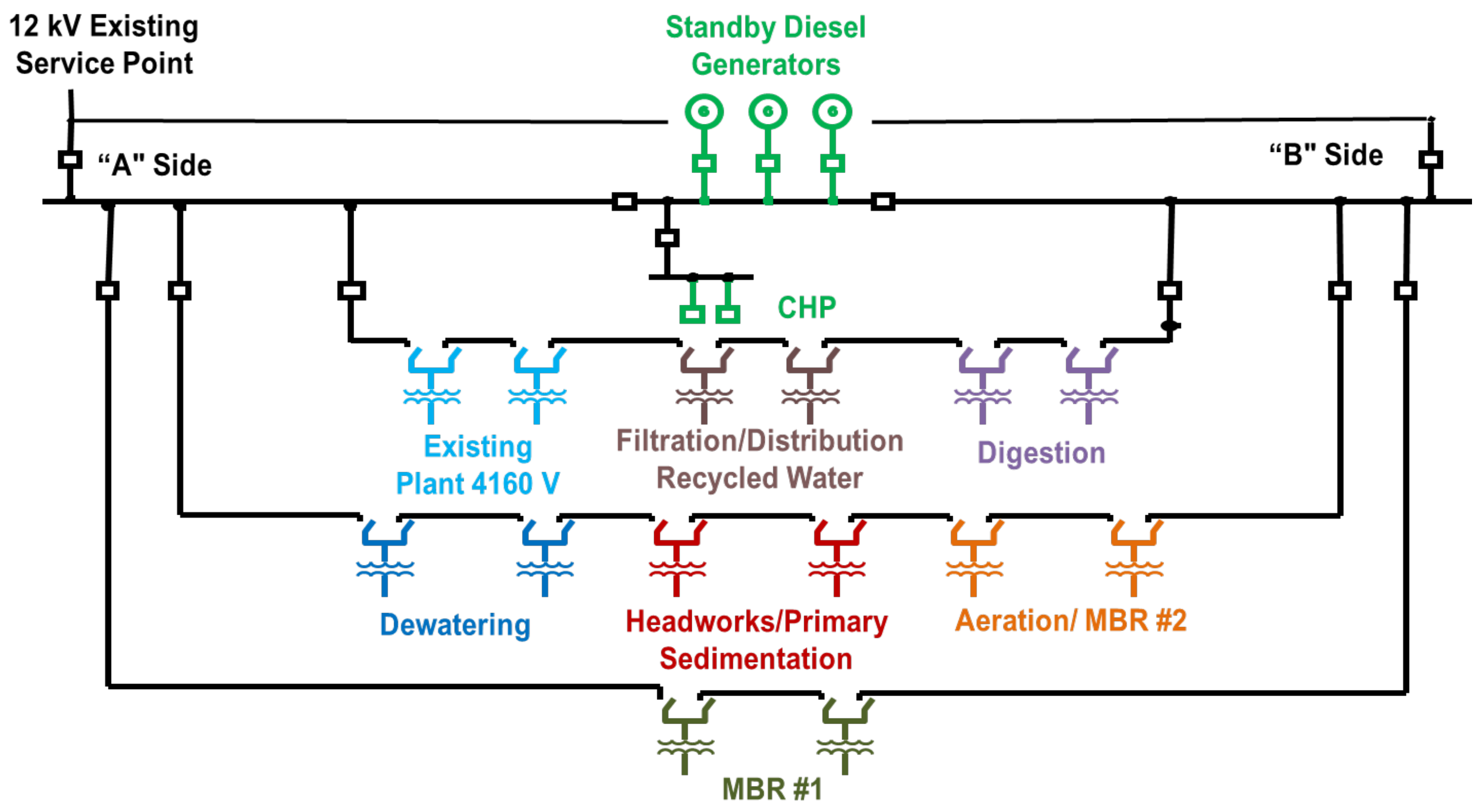

Figure 8
SINGLE LINE DIAGRAM FOR LOOP SYSTEM
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

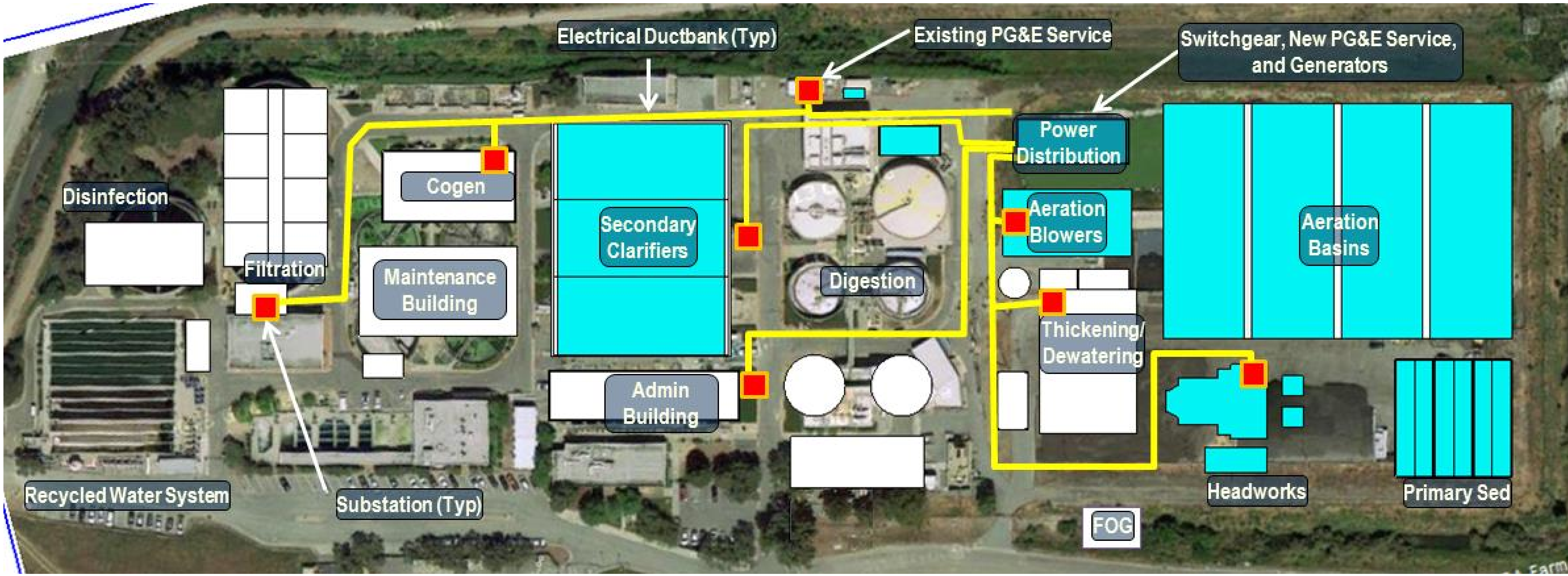

Figure 9
PRIMARY RADIAL SYSTEM DUCTBANK LAYOUT FOR ACTIVATED SLUDGE
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

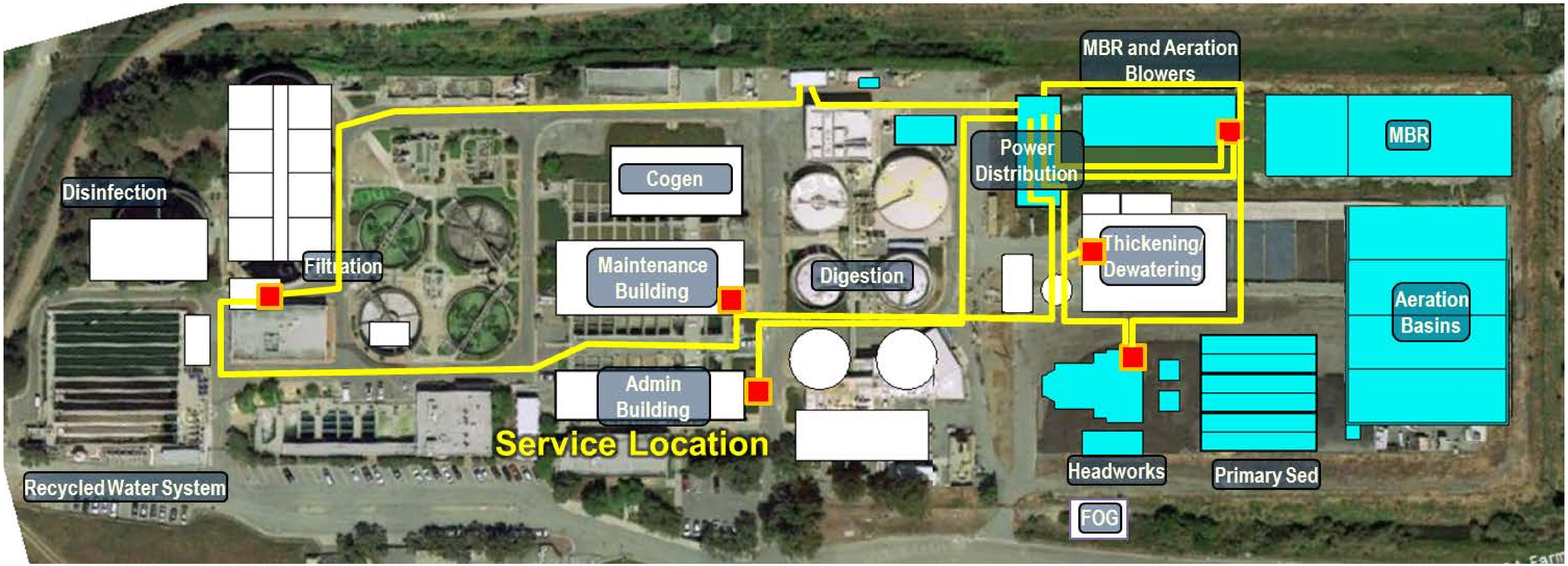

Figure 10
PRIMARY RADIAL SYSTEM DUCTBANK LAYOUT FOR MBR
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

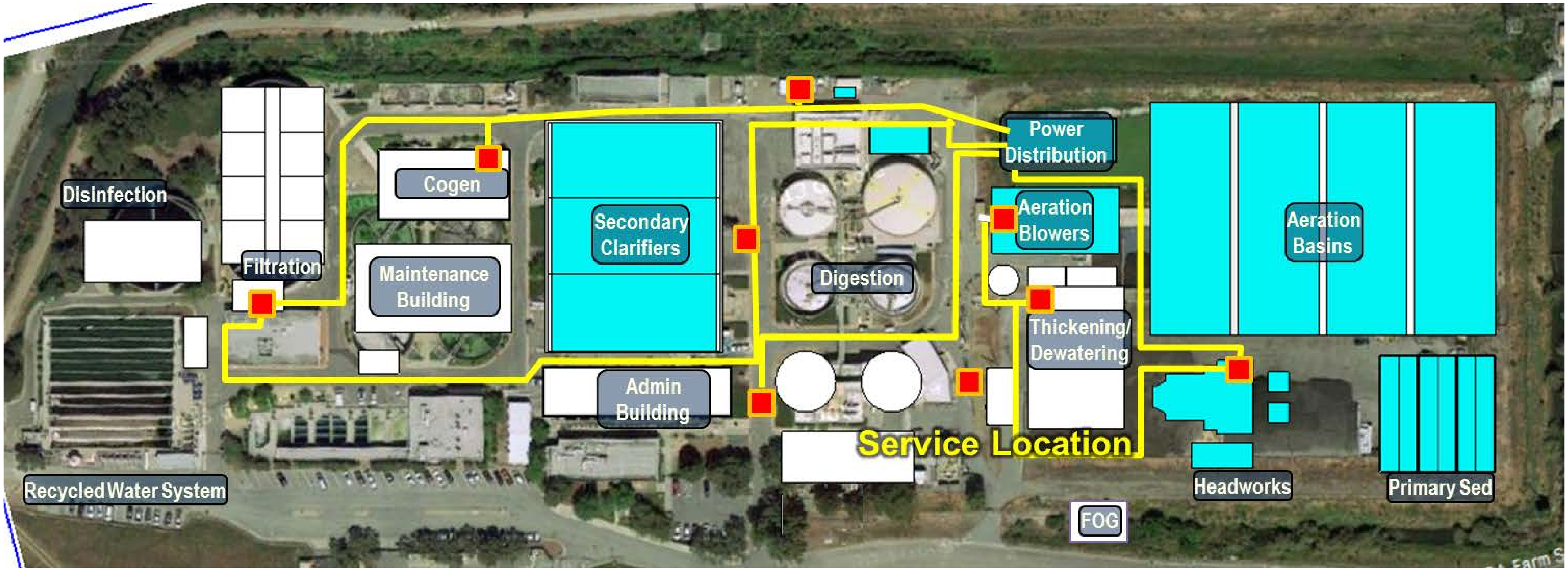

Figure 11
PRIMARY LOOP SYSTEM DUCTBANK LAYOUT FOR ACTIVATED SLUDGE
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

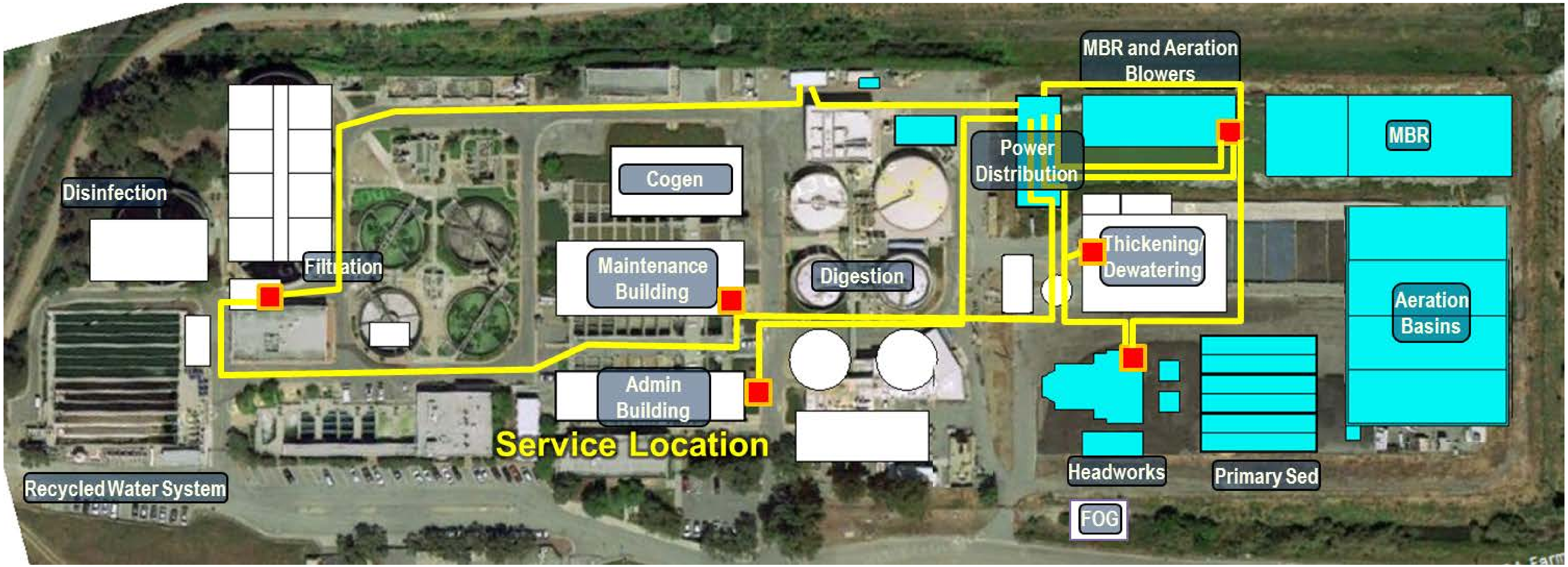

Figure 12
PRIMARY LOOP SYSTEM DUCTBANK LAYOUT FOR MBR
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

6.5.5 Cost Comparison

Table 8 below compares the cost differences only between the loop and radial configurations.

Table 8 Loop vs. Radial Cost Difference
Master Plan And Primary Treatment Design
City of Sunnyvale

Component	Cost
Loop Distribution System	
Ductbanks & conductors (3,160 ft. x $390/ft.)	$1,232,000 +/-
Switches (22 x $45,500)	$1,001,000 +/-
Total	**$2,233,000 +/-**
Radial Distribution System	
Ductbanks & conductors (5,700 ft. x $390/ft.)	$2,223,000 +/-
Additional CB’s at SWG	$520,000 +/-
Total	**$2,743,000 +/-**

6.5.6 Recommendation

The recommendation is to install the loop system due to the loop system being more reliable and having a lower cost.

6.6 Secondary Distribution System

The secondary distribution system is downstream of the 12kv to 480 volt transformer. The choices are between a simple radial system and a selective system. The simple radial system has the loads split in between two switchgear/MCC’s. The selective system has the loads split, but allows the two switchgear/MCC’s to be interconnected in case of losing a transformer.

6.6.1 Secondary Simple Radial

The 480 volt switchgear/MCC’s are electrically separate from each other in the simple radial system. The transformers are dedicated to a switchgear/MCC and are sized for 50% of the facility load. In case of a transformer failure 50% of the equipment will not be available for operation. Normally, most systems have an independent backup therefore capacity of the systems would be affected but in most cases will operate from 75 to 100 % of capacity. If additional reliability is desired for key processes, individual transfer switches can be installed to provide dual feeds to equipment. Figure 13 below shows a single line representation of this system.

6.6.1.1 Advantages

- The major advantage of the simple radial is the lower cost of the installation.

6.6.1.2 Disadvantages

- Single point of failure could reduce capacity of process.

6.6.2 Secondary Selective System

The 480 volt switchgear/MCC are tied together thru a tie-circuit breaker arrangement. The tie-circuit breakes allows one feeder to be shut down and both switchgear/MCC's to be fed from one feeder. Each transformer will be sized for the complete load of the facility. The operator selects which feeder to use to operate the facility. Figure 14 below shows a single line representation of this system.

6.6.2.1 Advantages

- The system is more reliable than the simple radial as the complete facility can operate in case of a transformer failure.
- Each substation/MCC has a back up source for failure on the primary side.
- Quick restoration of complete service in case of transformer failure.
- System has more flexibility for maintenance than simple radial.

6.6.2.2 Disadvantages

- Cost of the system is higher due to transformers having additional capacity and switchgear/MCC's having additional equipment.
- With larger transformers, the short circuit fault value is higher. The design and operations will have to take this into account. Short circuit fault value is a measure of the amount of energy available during a short circuit event. If you have more energy, the equipment has to be rated for the amount of energy which increases the cost of the system.

The advantages and disadvantages are summarized in the Table 9.

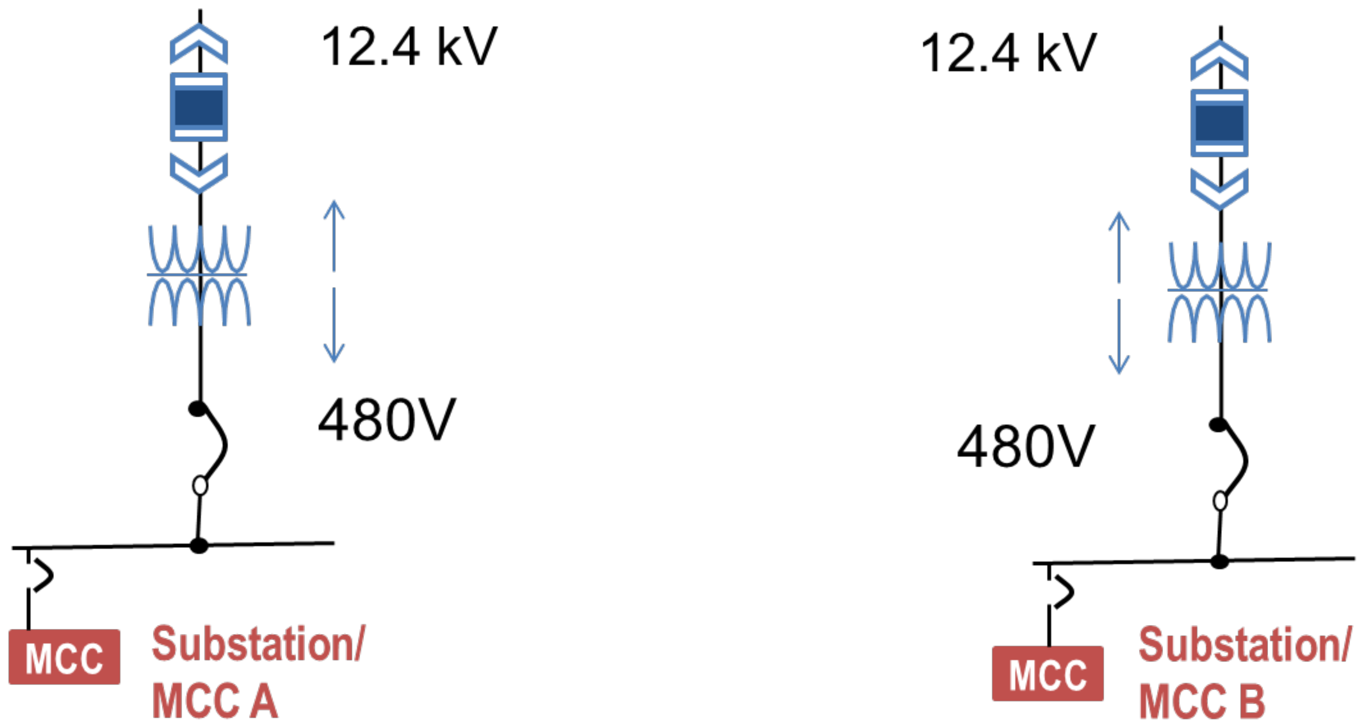

Figure 13
SECONDARY SIMPLE RADIAL
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

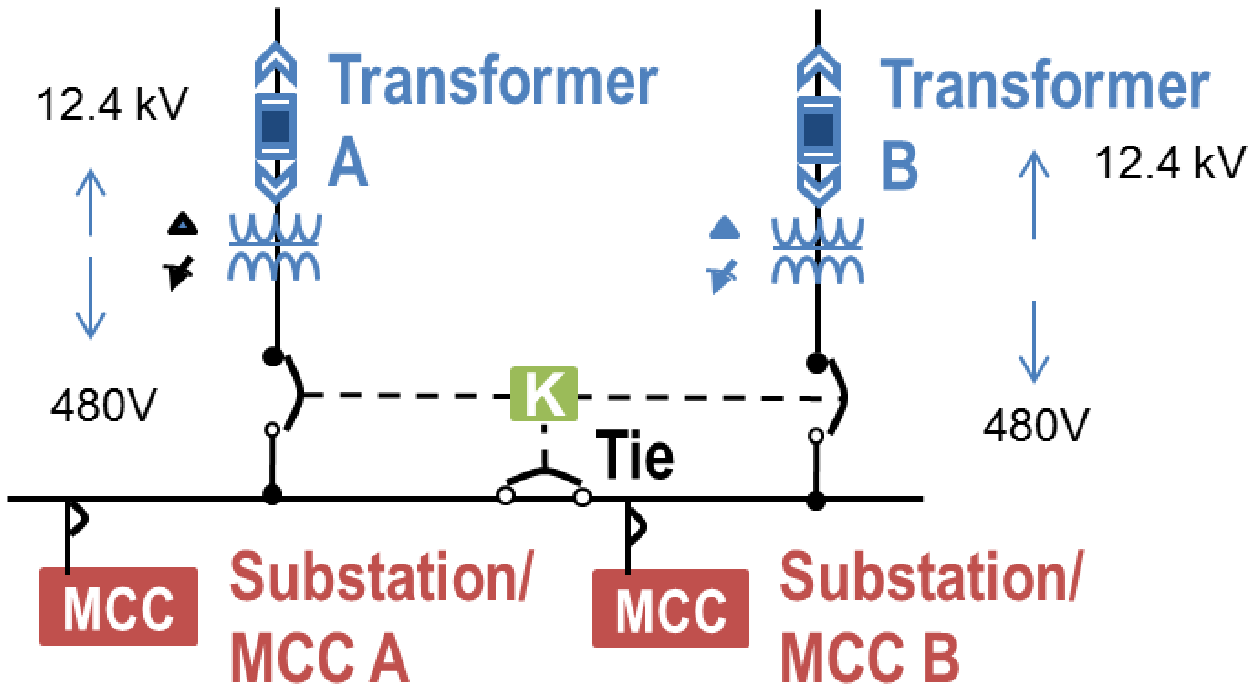

Figure 14
SECONDARY SELECTIVE SYSTEM
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

Table 9	**Comparison of Secondary Distribution System Alternatives Master Plan And Primary Treatment Design City of Sunnyvale**	
	Simple Radial	**Secondary Selective**
Capital Cost	+	0
Operating Cost	0	0
Safety	0	0
Reliability	0	+
Phased Construction Considerations	0	0
Notes: (1) Legend: + Better; 0 Neutral; - Worse		

6.6.3 Cost Comparison

Table 10 compares the cost differences only between the secondary selective and radial configurations.

Table 10 Secondary Selective vs. Radial Cost Difference Master Plan And Primary Treatment Design City of Sunnyvale	
Component	**Cost**
Secondary Selective System	
Transformers (2 @ $75,000)	$150,000 +/-
Switchgear (1 @ $250,000)	$250,000 +/-
Installation (1 @ $400,000)	$400,000 +/-
Total	**$800,000 +/-**
Radial Distribution System	
Transformers (2 @ $65,000)	$130,000 +/-

Table 10 Secondary Selective vs. Radial Cost Difference Master Plan And Primary Treatment Design City of Sunnyvale	
Component	**Cost**
Switchgear (2 @ $100,000)	$200,000 +/-
Installation (1 @ $400,000)	$400,000 +/-
Total	**$730,000 +/-**

6.6.4 Recommendation

The recommendation is to install a Secondary Selective System due to the higher level of reliability.

7.0 COMBINED HEAT AND POWER

7.1 Background

The WPCP has a cogeneration system known as the Power Generation Facility (PGF) that utilizes digester gas (DG), landfill gas (LFG), and air blended natural gas (ABNG). The facility has two Caterpillar engines rated for 815 kW each. The PGF has operated since 1996. The units are aging and are derated to approximately 600 kW each due to air quality considerations. No gas cleaning is provided except for removing moisture. During 2012, the facility produced an average of 1087 kW. The plant imported an average of approximately 73 kW from PG&E. The units operate in parallel with PG&E normally, but they can also be configured to operate as standby power for the plant. During utility outages, the PGF can operate in island mode but the operation is unstable. This is typical for gas fired engines because they cannot accommodate single load steps larger than approximately 10 percent of the engine capacity. Therefore, starting motors exceeding approximately 100 horsepower is difficult. The cogeneration facility has been estimated to have a useful remaining life of approximately 10 years due to the fact that: (1) parts are becoming more difficult to find, (2) O&M costs are increasing, (3) overall electrical efficiency of the PGF is significantly lower than with newer engine technology, and (4) modifications to the engines will be necessary to meet increasingly restrictive air emissions requirements.

7.2 Alternatives Discussion

Three technologies were considered for a new Combined Heat and Power (CHP) system at the WPCP: Engines, Microturbines, and Fuel Cells. Each technology has advantages and disadvantages that must be weighed for each specific installation and owner considerations.

The following discussion evaluates options for CHP and recommends a preferred option for future planning purposes.

7.3 Sizes, Efficiencies and Emissions Summary

Table 11 below provides a breakdown of equipment options and capacities for technologies considered. The sizes listed below are within the ranges needed for a CHP system at the plant that matches future average electrical demand of approximately 1,800 kW.

Table 11 CHP Equipment Available Sizes, Emissions, and Efficiencies
Master Plan And Primary Treatment Design
City of Sunnyvale

Mfg. Model No.	Capacity, kW	Efficiency, %	NOx Emissions, ppm
Engines (GE Jenbacher)			
312	633	38	34
412	852	39.2	34
416	1,147	39.1	34
Microturbines (Capstone)			
CR600	600	33	9
CR800	800	33	9
CR1000	1,000	33	9
Fuel Cells (Fuel Cell Energy)			
DFC300	300	45	1
DFC1500	1,400	45	1
DFC3000	2,800	45	1

7.4 Internal Combustion Engines

Gas-fired internal combustion engines are the most common and longest used CHP technology at wastewater treatment plants. With a proven performance history, there are numerous installations on biogas that have operated successfully for many years. There are several major manufacturers of engines that supply for the biogas market. The most common manufacturers include GE (Jenbacher and Waukesha brands), Caterpillar (Caterpillar and MWM brands), Cummins, MTU, and Guascor. An example IC engine is shown in Figure 15.

Figure 15
IC ENGINE
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

Technology has continued to improve such that manufacturers are able to produce engines with electrical efficiencies in excess of 38%. Most also are able to operate with lower pressure fuel- as low as 2 psi- reducing the impact of parasitic loads on the net electrical capacity of the system. Engines also have very good quality heat for heat recovery. High temperature heat is available from the engine jacket and the engine exhaust. Lower temperature heat is available from the aftercooler and lube oil system. Full use of heat can be achieved when low temperature heat is used for space heating.

Engine emissions have also improved significantly in recent years. However, they are not the cleanest combustion technology and therefore require emissions after treatment to meet emissions requirements in California. In the Bay Area engines are required to use oxidation catalysts to remove Carbon Monoxide (CO) and Selective Catalytic Reduction (SCR) for removal of Oxides of Nitrogen (NOx). Oxidation Catalysts are passive systems while SCRs require a urea solution to be sprayed over the catalyst to react with the NOx. This results in additional maintenance and operating costs.

The largest engine manufacturers (GE, Caterpillar, and Cummins) have solid support networks with parts and service to support operations of their equipment. Caution is advised when considering lesser known manufacturers in the US as their service networks are limited so could impact time for parts and service to arrive.

Engines have historically been the most resilient equipment burning biogas; however, technology improvements and emissions after treatment have changed the requirements for fuel quality. In order to protect emissions catalysts and meet engine fuel requirements, contaminants and moisture must be removed.

7.5 Microturbines

Microturbines have been in the biogas power generation market for several years. Early in their history, they had very poor performance with biogas and poor electrical efficiency. As a result there were few installations and those that were installed tended to be smaller pilot projects. In recent years improvements have been made, but microturbines still have limited successful operating history using biogas. There are two companies currently offering microturbines for biogas applications- Capstone and Flex Energy. Capstone is more experienced and currently offers packaged systems that are within the size range that Sunnyvale could consider for its CHP system. The Flex Energy system is actually a retooling of Ingersoll Rand microturbines. Their products are currently offered in small size increments but could be combined on site to create overall systems that meet the requirements of the proposed CHP system. An example microturbine is shown in Figure 16.

The electrical efficiency of microturbines has now improved to rival the lower end of engine efficiencies. Microturbines are now available with equipment efficiencies of 33%. One large caveat with efficiencies is that the efficiencies cited by manufacturers do not include parasitic loads. Microturbines require fuel pressure of up to 100 psi, which can be equivalent to several percentage points of net efficiency lost.

Historically, a criticism of microturbines was that they required more extensive biogas treatment than engines. Further, there were also misapplication of gas clean up technologies or belief that clean up was not required, so numerous installations had operational problems. With better understanding of gas cleaning up technologies and

increasing requirements for engines, microturbines and engines have essentially the same biogas quality requirements.

Heat recovery for the larger units is adequate to cover the needs of the City. One of the limits to heat recovery of microturbines has been that internal heat use in a recuperator reduces the amount and quality of heat available. However, technological advancements have allowed for efficiency improvements while also providing sufficient heat for plant heating needs.

A significant advantage that microturbines offer over engines is that their emissions meet California emissions requirements without after-treatment. In particular, the microturbine NOx emissions are below Bay Area standards for SCR technology, which offers simpler operations for at least that part of the system.

7.6 Fuel Cells

It could be argued that fuel cells have been attempting to move out of a developmental stage for the better part of the last decade. Cost has been the single biggest obstacle to their adoption. This is true for both capital and operating costs. Costs for the initial equipment on a $/kW basis is still significantly higher than other technologies. Operating costs, when fuel cell stack replacement is included, also exceed other generating technologies. Historically, fuel cells have only been cost competitive when incentives were available for their installation. An example fuel cell is shown in Figure 17.

Fuel cell costs have improved dramatically, but still continue to exceed significantly the levels of engines and microturbines. A second factor to higher cost is the fact that only a single manufacturer exists that is offering a product in the size range being considered for this project. Fuel Cell Energy, using a molten carbonate fuel cell technology, is the only commercially viable manufacturer at this point, which would limit competitive procurement. Fuel Cell Energy has failed to make a profit since its existence. The long term financial viability of the company is questionable given the high cost of their equipment and apparent high costs of their business model, which has not yielded any profits.

Aside from the cost considerations, there are performance positives and negatives to consider when evaluating fuel cells.

Figure 16
MICROTURBINE
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

Figure 17
FUEL CELL
ELECTRICAL & COMBINED HEAT AND POWER PLAN
MASTER PLAN AND PRIMARY TREATMENT DESIGN
CITY OF SUNNYVALE

Two advantages of fuel cells over engines and microturbines are their high efficiency and low emissions. Fuel cells have the highest fuel to wire efficiency: 45 percent. Emissions for fuel cells are the lowest by far of any generating technology, requiring no after-treatment and minimal air permitting requirements.

Fuel cells have three operational disadvantages: (1) more limited waste heat availability, (2) very stringent fuel quality requirements, and (3) longer start up times. Because of their higher electrical efficiency, fuel cells will have less heat available for plant heating needs. In the case of Sunnyvale, heat needs for digestion are well below the heat available from fuel cells. However, if space heating is included and if space cooling is considered, the lower amount of heat available could be an issue. The fuel quality requirement becomes an issue if fuel quality is off spec and the units switch to natural gas. Fuel switching could result in more biogas being flared, which would reduce the revenue of the generation system through lost fuel and purchased natural gas. The fuel switching is necessary because fuel cells do not have the ability to start up and shut down as easily as engines and microturbines. It typically takes several minutes to a half hour for the fuel stack to come up to temperature and be operating at full load. Switching to natural gas avoids dropping offline and keeping the unit in hot idle or fully operating on natural gas.

7.7 Alternatives Evaluation

Project pro formas were developed for potential CHP alternatives to evaluate the generating technology which would provide the best return on investment for Sunnyvale. Prior to cost development, it was determined that fuel cells would not be a competitive alternative and were therefore eliminated from consideration. The alternatives evaluated are between engines and microturbines. The size selected for the cost analysis was 1,700-1,800 kW to align with average power need at the plant in 2025. Space will be made available in facility layout to add a third generator in the future as plant load increases.

Table 12 presents the pro forma for engines.

Table 13 presents the pro forma for microturbines.

The pro forma for microturbines is based on an 1,800 kW system. The same assumptions for natural gas use and discount rate are applied to the analysis.

Table 14 presents comparative evaluation of engines and microturbines using cost and non-cost criteria.

Table 12	**Cost Information for 1,700 kW Internal Combustion Engine Master Plan And Primary Treatment Design City of Sunnyvale**
Operating Output, kW	1,700 +/-
Capital Cost (2020)	$10,450,000 +/-
Yearly Gross Revenue @ 15¢/kWh	$2,100,000 +/-
Yearly Gross Revenue @ 20¢/kWh	$2,800,000 +/-
Yearly O&M Costs	$400,000 +/-
Yearly Fuel (Natural Gas) ($6/MMBTU)*	$200,000 +/-
Yearly Net Revenue @ 15¢/kWh	$1,500,000 +/-
Yearly Net Revenue @ 20¢/kWh	$2,200,000 +/-
Present Worth of Savings (15¢/kWh)**	$20,385,490 +/-
Present Worth of Savings (20/kWh)**	$29,898,718 +/-
Simple Payback, years (15¢/kWh)**	7.0
Simple Payback, years (20/kWh)**	4.8
Notes: (1) *Natural Gas @ $12/MMBTU Decreases PW of Savings by $3,000,000 (2) **4% Discount Rate, 20 yr.	

Table 13	**Cost Information for 1,800 kW Microturbine Master Plan And Primary Treatment Design City of Sunnyvale**
	With NG
Operating Output	1,800 +/-
Capital Cost (2020)	$11,440,000 +/-
Yearly Gross Revenue @ 15¢/kWh	$2,200,000 +/-
Yearly Gross Revenue @ 20¢/kWh	$3,000,000 +/-
O&M Costs	$600,000 +/-
Yearly Fuel (Natural Gas) ($6/MMBTU)*	$400,000 +/-
Yearly Net Revenue @ 15¢/kWh	$1,200,000 +/-
Yearly Net Revenue @ 20¢/kWh	$2,000,000 +/-

Table 13	**Cost Information for 1,800 kW Microturbine Master Plan And Primary Treatment Design City of Sunnyvale**
	With NG
Present Worth of Savings (15¢/kWh)**	$16,308,392 +/-
Present Worth of Savings (20¢/kWh)**	$27,180,653 +/-
Simple Payback, years (15¢/kWh)**	9.5
Simple Payback, years (20¢/kWh)**	5.7
Notes: (1) *Natural Gas @ $12/MMBTU Decreases PW of Savings by $5,000,000 (2) **4% Discount Rate, 20 yr.	

Table 14	**Comparison of Cogeneration Alternatives Master Plan And Primary Treatment Design City of Sunnyvale**	
	IC Engines	**Microturbines**
Capital Cost	0	–
Operating Cost	0	0
Efficiency	+	0
Parasitic Loads	+	0
Gas Treatment Requirements	0	0
Reliability Using Biogas	+`	–
Air Permitting Issues	–	+
Notes: (1) Legend: + Better; 0 Neutral; - Worse		

7.8 Recommendations

As described above, pro formas and non-economic factors indicate that there are some advantages to installation of internal combustion engines as the CHP technology, although microturbines as an option are relatively close. If the CHP design commences within the next

4 years, it is recommended that the City select engines for the system. Engines are less expensive, are proven performers with biogas, and are more efficient. If microturbine performance on biogas is confirmed over the next 3-4 years, then they could be reconsidered as a CHP alternative. Engines currently achieve emissions limits with after treatment technologies provided, while microturbines are not required to treat exhaust for emissions control.

Based on projected electrical power costs, the economic evaluation indicates that operating the CHP at a full load will provide a better present worth than operating at a reduce load on biogas only. Therefore, any project going forward should include biogas/natural gas blending as a project feature.

Additional power generation on site can be considered using photovoltaics. However, site constraints would not allow installation in the process areas. Installations of photovoltaic arrays in the pond can be considered in the future. Rooftop arrays can also be considered, although production will likely be small (less than 20 kW).

7.9 Sizing of Engines

The recommended size of the CHP system should be in the range of 1700-2100 kW. This will allow for a CHP system that can provide all average power consumption at the treatment plant with a year 2025 operating capacity. CHP system capacity can be expanded with a third engine in the future if electrical demand is higher than anticipated now.

7.10 Ownership

Ownership options were also considered for how to procure the CHP system. Ownership options considered include City ownership and operation as well as public/private partnerships. Public/private partnerships can take on many different forms, ranging from city ownership and contracting of operations, to City fully outsourcing ownership by selling raw gas and purchasing power and heat from a privately owned and operated facility.

While the varying degrees of private involvement in ownership can provide capital cost reduction, the City loses control and revenue opportunities when private partners are engaged. Due to the importance of heat provided by the system for plant operations, the City’s existing capabilities for operation and maintenance of the power generation facility, and the benefits of full electricity cost offsetting through ownership of the CHP, City staff determined that it was more beneficial to remain the owner and operator of the new CHP facility.

7.11 CHP Location and Configuration

Originally, the CHP system was envisioned as a new stand alone facility to be located north of the new secondary clarifiers. As the site master planning progressed in the summer of 2014, it became apparent that plant site could not accommodate the footprint needed for the new

CHP facility plus the possible additional footprint needed for a boiler building. It was decided that the most practical location for the CHP facility will be at the location of the existing PGF facilities. Two configuration options were considered for the CHP facility improvements in 2020-2025: 1) provide new engines and heat recovery equipment inside the existing PGF building with gas cleaning located outside immediately to the east of the PGF building and 2) demolish the existing PGF facility and construct an entirely new CHP facility at that location using the footprint available. Option 1 above has been selected due to ease of construction, ability to make interim improvements to the existing PGF (10 year horizon), and reduced engine downtime during construction.

8.0 HEAT RECOVERY

8.1 Background

Significant waste heat is generated by the existing (and future) cogeneration engines, which is able to be recovered and used throughout the plant. Several locations on the WPCP site could take advantage of this heat, including the digesters and administration/maintenance buildings. The plant currently has jacket and exhaust heat recovery at the IPS engines, along with jacket recovery at the PGF. When the IPS is removed this heat source will be lost. When this happens, the PGF will not be able to provide reliable recoverable heat from now until the new CHP system is constructed (possibly as late at 2025)

8.2 Heat Balance

The projected heat balance in 2035 is summarized in Table 15. Building heat will be provided from the plant heat loop. However, the individual building HVAC systems will be designed to run on their own natural gas feeds if emergency needs require it.

Table 15 Plant 2035 Heat Balance
Master Plan And Primary Treatment Design
City of Sunnyvale

	Heat Load Location	Heat Loads
1	CHP Recoverable Heat @ 1,200 kW	4,000,000 BTUH
2	CHP Recoverable heat @ 1,700 kW	5,700,000 BTUH
3	Digester Heating Requirements 2035 Max Month Solids (45,000 lbs./day @ 4.5%) Environmental Losses Total Digester Heating Load	 1,500,000 BTUH 300,000 BTUH 1,800,000 BTUH

Table 15	Plant 2035 Heat Balance Master Plan And Primary Treatment Design City of Sunnyvale	
	Heat Load Location	**Heat Loads**
4	Building Heat (Peak) Load (18,000 SF @ 40 BTU/SF)	700,000 BTUH
5	Total Plant Heat Load	2,500,000 BTUH
6.	Excess Heat for Other Buildings or uses such as biosolids drying	1,500,000 – 3,200,000 BTUH

8.3 Interim PGF Improvements (Controls and Heat Recovery)

When the engines in the primary control building are decommissioned, the sole source of heat for digesters and all buildings will be the PGF. Currently, process heat is provided for the hot water loop system by heat recovered from the engines in the primary control building (raw sewage pump engines) using jacket and exhaust heat recovery as well as from PGF Jacket heat recovery . A total of 0.8 MMBTUH can be provided by the IPS engines. Jacket water heat recovery for the PGF can provide approximately 1.9 MMBTUH (both engines operating). As indicated in Table 15, the heat load is anticipated to be 2.5 MMBTUH. Therefore, the existing PGF facility will not be able to reliably provide heat needs for the next 10 years. The PGF engines currently do not have exhaust heat recovery that could add a total of 4 MMBTUH (both engines operating).

Four interim heat recovery alternatives were considered for supplying heat after the IPS engines are decommissioned and until the new CHP facility is operational. These alternatives are described on appendix B of this document. The recommended alternative to provide reliable process and building heat for the next 5-10 years is to provide updated PGF controls and exhaust heat recovery for the two existing PGF engines. Gas cleaning will not be provided now. A backup boiler will not be provided now but it can be added to the third bay of the PGF building later. The estimated cost of this alternative is $1,430,000.

8.4 Recommendations

Waste heat recovery is a sustainable use of the WPCP's resources. Heat recovery recommendations include:

- Hot water loops will be provided to the digesters and new administration and maintenance buildings
- Other buildings will be considered after final loadings are determined

- Provide updated PGF controls and exhaust heat recovery for the two existing PGF engines. Gas treatment will not be installed now. Design should begin immediately.

- The new CHP facility will have engine jacket and exhaust heat recovery(assuming engines are chosen)

- A backup boiler will not be installed now but can be installed later in the third bay of the PGF or in the new CHP building.

9.0 AIR PERMITTING

Air emissions are regulated by the Bay Area Air Quality Management District (BAAQMD). Requirements for engine emission are:

- 70 ppmv NOx

- 2000 ppmv CO

- Oxidation catalyst for CO reduction

- SCR for NOx reduction now required

Requirements for turbines are:

- 50 ppmv NOx

Turbines are able to achieve emissions limits without after treatment. A future consideration for engines emissions control may be the addition of continuous emissions monitoring systems. While this is not currently a requirement, it may be required at some point in the future, which would further increase cost and complications of operating an engine based CHP system.

APPENDIX A – ELECTRICAL AND COMBINED HEAT AND POWER WORKSHOP MINUTES AND SLIDES – DECEMBER 5TH, 2013

Engineers...Working Wonders With Water™

CONFERENCE MEMORANDUM

Project:	Master Plan and Primary Treatment Design	**Conf. Date:**	December 5, 2013
Client:	City of Sunnyvale	**Issue Date:**	December 24, 2013
Location:			
Attendees:	City: Bryan Berdeen Dan Hammons Craig Mobeck Manuel Pineda Kent Steffens John Stufflebean	Carollo/HDR/Subconsultants: Jamel Demir Jim Hagstrom Katy Rogers Dana Hunt Larry Smithey Jeremy Holland Dave Reardon Alex Ekster Boris Pastushenko	
Purpose:	Electric and Combined Heat and Power (ECHP) Workshop (Workshop 3)		
Distribution:	Attendees, Bhavani Yerrapotu, Eric Casares	**File:**	9265A.00

Discussion:
The following is our understanding of the subject matter covered in this conference. If this differs with your understanding, please notify us.

1. **INTRODUCTION**
   a. **Discussion**
      1) The ECHP master planning effort should account for future loads for Ultra Violet (UV) and Reverse Osmosis (RO).
      2) City staff issues were presented and discussed.
2. **ENERGY BALANCE**
   a. **Discussion**
      1) Energy balance was discussed. Plant is essentially electricity neutral but purchases natural gas. Future plant loads were presented and categorized as critical standby loads, normal standby loads, peak duty loads, and connected loads.
      2) Biogas production was presented and shows biogas production of 452,000-497,000 cubic feet per day (cfd) in 2035(all biogas normalized to 550 British Thermal Units (BTU) gas)

3) Standby storage of primary effluent (PE) was discussed. 2-3 days of emergency storage for PE is anticipated (to be finalized as part of the process criticality discussion).

4) Standby loads for 2035 were presented

   a) Standby loads were developed to achieve different levels of criticality:

      (1) Human health and safety

      (2) Meeting permit requirements

      (3) Protecting the process

      (4) Protecting equipment

5) Biogas Production

   a) Landfill gas production is expected to decrease by approximately 2% per year. The BTU value of the gas might decrease with time. This needs to be evaluated further at the time of design of the CHP system. During the discussion, the year 2030 was mentioned as the time when quantity and quality of the landfill gas might make its use impractical.

   b) Biogas production values from digesters are based on a metric of 13 cf biogas per # Volatile Solids (VS) destroyed. A discussion followed. This value is considered conservative based on future criteria for operation of a Nitrification/ Denitrification (NDN) activated sludge system.

   c) Fats, Oils and Grease (FOG) will contribute approximately 10% of the biogas total. The numbers were derived from the Kennedy report. The assumptions of the Kennedy FOG report are considered reasonable by Carollo/HDR.

   d) Food waste receiving was discussed. Processing of food waste on site is not practical due to labor requirements and odor potential. If food waste is prescreened and in liquid form, it can be considered as a feedstock for the digesters. Biogas production listed above does not include food waste digestion. The city should not count on FOG feedstock beyond the City limits.

6) CHP can not be counted as standby power.

7) It is more economical to purchase natural gas now for use in CHP than to purchase electricity.

8) Enhancing Biogas Production

   a) Improving performance of primary clarifiers. Strategic baffling might improve SS removal and this diverts more solids to the digesters, thus enhancing biogas production. A discussion ensued and it was decided that the increase was potentially small enough that the master planning gas production numbers would not be increased above the levels indicated previously in the minutes.

   b) Waste Activated Sludge (WAS) Pretreatment Options

      (1) Many WAS pretreatment options are being considered in the industry to improve the digestibility of WAS.

      (2) There are many technologies that need to mature before we consider them.

(3) It was decided that WAS (from activated sludge or MBRs) would probably be digested and not stabilized in some other way (such as lime stabilization) although this could be revisited later. All biosolids must meet 503 regulations.

(4) The Bay Area Biosolids Group is pilot testing a gasifier on a large scale (potentially at San Jose). Results will shake out for this technology and other technologies over the next five years, and Sunnyvale can benefit by deciding later on WAS pretreatment options.

c) Thermophilic Digestion or Temperature Phased Anaerobic Digestion (TPAD)

(1) A key driver for TPAD is if Class A biosolids are needed.

(2) Thermophilic or TPAD may not be practical unless a Class A biosolids product is desired.

9) Energy Balance Summary

a) The Water Pollution Control Plant (WPCP) may be essentially electricity neutral but it is not "energy neutral" because the plant buys natural gas for Influent Pumping Station (IPS) engines and Power Generation Facility (PGF).

b) A question was asked if the City will be a long term buyer of natural gas and if the city is getting a good price. The city is buying gas through a consortium at a discount now.

c) The CHP schedule shows possible implementation 7 – 10 years from now. Two things are driving it: 1) It will be harder and harder to find parts/controls for the existing engines and 2) the CDM report indicates the engines have about 10 years of remaining useful life. A discussion followed suggesting that it might make sense to move the implementation up to take into account the following issues:

(1) Improved efficiency of modern engines.

(2) Required investment in air quality equipment for existing PGF.

(3) High Operation & Maintenance (O&M) costs of existing PGF.

b. **<u>Decisions</u>**

1) ECHP system planning should include considerations of possible future UV and RO facilities.
2) WAS pretreatment prior to digestion will not be considered at this time.
3) Landfill gas use in CHP may not be practical after 2030.
4) Mesophilic digestion of biosolids is anticipated.
5) FOG receiving for material within City limits is anticipated.
6) Food waste receiving will not be considered unless it is pre-processed and in liquid form. Anticipated biogas values do not include food waste digestion (separate tank for food waste would be provided as part of the FOG facility to accommodate emulsified food waste product).
7) CHP implementation sooner than year 2020 is being considered.

c. **<u>Action Items</u>**

1) Carollo/HDR to investigate possible decline in landfill gas quality over time.

3. **STANDBY POWER**

a. **Discussion**

1) Two options considered: 1) Standby Diesel Engine Driven Generators and 2) Two Independent 12 kilovolt (KV) Electrical Services from PG&E.

2) A hybrid system was discussed (i.e., standby and independent service), but it was pointed out that the cost of this option has considerable initial and ongoing costs/charges that make this too expensive. Also, the National Electric Code does not recognize two independent electrical services as acceptable standby power.

3) Recommend implementing standby diesel engine driven generators. The standby power system will not have additional "standby" equipment.

4) Standby Power Enclosure Alternatives

a) Two alternatives considered: 1) conventional building and 2) outdoor walk-in enclosure. Both can be designed to noise attenuation of 75 decibel (dB) at 20 feet

b) The tentative decision is to go with the outdoor enclosure. Both types of enclosures will be visited at Sacramento and Vacaville by WPCP staff as part of making final decision. Outdoor enclosure concept has a lower construction cost.

5) Black Start and Island Mode Operation

a) Black Start is defined as the mode when Pacific Gas & Electric Company (PG&E) power fails and you need to start and run the plant without power from PG&E.

b) Island mode is when the standby power system is operating independently from the grid, i.e. the treatment plant power system is not connected to the PG&E grid.

c) The standby power system will be designed to operate in black start and island mode scenarios.

b. **Decisions**

1) Standby power will be provided on site with diesel engines with a capacity of 4 - 4.5 megawatts (MW) depending on selection of membrane bioreactors (MBRs) or conventional activated sludge.

2) Outdoor enclosures are tentatively recommended with confirmation upon field trip to Vacaville and Sacramento.

3) Standby power is needed soon for the new primary treatment design program.

c. **Action Items**

1) Carollo/HDR to set up site visits with City staff to see building enclosures and outdoor enclosures for standby power generators. Trip is scheduled for January 8, 2014.

4. **CHP ALTERNATIVES (Cogeneration)**

a. **Discussion**

1) Options for CHP at Sunnyvale

a) Planning considerations include technology options, sizing and use of NG, permitting, retirement of existing PGF.

b) Options are engines, microturbines, fuel cells.

c) Key engine suppliers are Caterpillar, Jenbacher, and Cummins.

d) Microturbine efficiency has improved considerably. The numbers presented are only reflective of the output they actually provide. They do not reflect the parasitic load. Modern engines currently run at 1.5 – 2 pounds per square inch (psi). Microturbines require compressing the biogas to 50 - 100 psi.

e) We will capture waste heat from all technologies.

f) Gas pretreatment is about the same for all three technologies considered.

2) Internal Combustion Engines

a) Many advantages. The major drawback with engines is meeting the emissions standards. Efficiency is high- 38 - 40% electrical efficiency.

3) Microturbines

a) Poor record to date with biogas. Air permitting is usually not an issue. Lower efficiency - approximately 30% after parasitic losses (gas compression).

4) Fuel Cells

a) Lowest emissions and highest efficiency; however, they are only cost effective when grant options are available. Fuel Cell systems are more black box systems than the other technologies (e.g., maintenance is contracted out). Fuel cells were ruled out as an option.

5) Possible CHP Facility Sizing

a) 475,000 cf biogas will produce approximately 1,200 kilowatt (kW) at 38% electrical efficiency.

b) Plant load (activated sludge) will be approximately 1,800 kW in 2025.

c) CHP must be able to accommodate daily and seasonal variations in biogas production. Storage and feed of FOG can be used to attenuate variations. Gas storage is not anticipated.

6) Options for CHP Ownership and Operation

a) The City prefers that the City own and operate the CHP system although the only caveat is limited bonding capacity.

b) SGIP: Self Generation Incentive Program can provide some funding. $1.14/Watt. So for 1,700 – 2,100 kW systems that would amount to between $1.9 - $2.4 M in incentive. The incentive is the same for either Internal Combustion (IC) Engines or Microturbines.

c) Renewable Energy Credits (RECs): Utilities use RECs to meet renewable energy portfolio standards requirements or to sell customers renewable energy. A REC encompasses the environmental attributes of 1 Megawatt-hour (MWH) of renewable energy. RECs for renewable energy portfolio standards are compliance based and are worth less than RECs used to sell customers renewable energy through green energy programs. The value of RECs varies as the requirements are based on a specific utility's needs and whether they are purchasing compliance RECs or RECs for green energy programs. Values can range from as little as $.60/MWH to as much as $4.00/MWH. The range greatly depends on whether the REC is being purchased to comply with a renewable power portfolio standard requirement or as part of a voluntary green energy program.

7) Cost Information for 1,700 kW IC Engine and 1800 kW Microturbine CHP
    a) A present worth analysis was presented showing considerable difference in present worth costs with/without NG. Present worth showed considerably higher PW when using NG because of significantly higher value of power produces and low cost of NG. Comparing the present worth of the engines vs. microturbines makes the engines a slightly more attractive option.
8) Evaluation of Cogeneration Alternatives
    a) Gas treatment has a big impact on the performance of microturbines. They need clean gas. Early microturbines failed due to gas quality issues. They are improving but limited successful installations exist.
    b) Air permitting is a major factor for IC engines.
9) Cogeneration Recommendations
    (1) Today: IC Engines. Engine technology is more proven right now.
    (2) 2020: IC engines or microturbines depending on air permitting, efficiency and reliability considerations.
    (3) Size: 1,700 – 2,100 kW
    (4) CHP is not considered standby power although it can be manually started and used in case of an extended power outage.

b. **Decisions**

1) Fuel cells are eliminated as an option.
2) IC engines recommended if CHP is designed/installed within 3 - 5 years.
3) Microturbines should be considered further if installation is 2020 or beyond depending on efficiency, proven performance with biogas and air permitting.
4) Size will be approximately 1,700 – 2,100 kW, possibly larger if MBRs are chosen. CHP design should include equipment for augmentation with natural gas. Two engines initially (if engines are selected) with capability to add an additional engine in future if additional load from UV or RO increases plant load.

c. **Action Items**

1) Include sensitivity analysis for natural gas and electricity costs in preparation of technical memorandum.
2) Discuss cost, advantages and disadvantages of accelerating CHP implementation in the technical memorandum.

5. **ELECTRICAL DISTRIBUTION**

a. **Discussion**

1) Two Future Plant Distribution System Configuration Options Considered:
    a) Radial – From substation straight out to transformer.
    b) Loop – Loop around the WPCP with drop offs to the individual transformers.
2) Carollo/HDR recommends plant distribution voltage of 12 kV versus 4.16 kV.

3) Carollo/HDR recommends a loop system over a radial system because it is lower cost and is technically equivalent: In addition, the loop system has a smaller footprint. It includes one duct bank where the radial system includes two duct banks. There may be some sub loops oversizing needed for phasing of the loop construction. This will be done as part of the Site Planning.
4) For secondary distribution, Carollo/HDR recommends a secondary selective system over a simple radial system. It is a higher cost but is more reliable.
5) Main switchgear will be designed for 10 megawatt (MW).

b. **Decisions**

1) Loop distribution system.
2) Secondary selective systems for secondary distribution.
3) 12 kV distribution.

6. **HEAT RECOVERY FROM COGENERATION: ACTIVATED SLUDGE**

a. **Discussion**

1) Heating system will provide heat to the maintenance and admin building. Chilled water could also be provided to these buildings. Other buildings can be considered for hot and chill water connections. The SMART station, which is roughly 1,500 feet away from the plant, can also be considered.
2) The heating system could be expanded to the thickening and dewatering building if the loads warrant it.
3) The plant would have excess heat with the proposed CHP system. This waste heat could be used for biosolids drying (slipstream) or other uses.
4) Carollo/HDR recommends a dual fuel boiler to provide backup heat to the WPCP should the heat recovery system fail or be out of service. This boiler will likely be included in the Primary Treatment Design.
5) Standby boiler. There was considerable discussion of the need for a standby boiler if the CHP system is down. It was ultimately decided that a standby boiler is necessary.

b. **Decisions**

1) Waste heat will be utilized for digester heating.
2) Waste heat and chilled water loops will be provided for administration and maintenance buildings. Additional buildings will be considered after loads for administration and maintenance buildings are confirmed.
3) Standby boiler will be provided to produce heat if CHP is down.

c. **Action Items**

1) Carollo/HDR to determine where boiler should be located as part of the Site Plan.

7. **AIR PERMITTING**

a. **Discussion**

1) In future, engines may require continuous emissions monitoring systems, potentially within the next 5 years.

2) It will cost about $0.5 million (M) to meet Bay Area Air Quality Management District (BAAQMD) requirements for the existing Power Generation Facilities (PGFs).
3) Best Available Control Technologies (BACT) does not currently require emissions monitoring systems (CEMS).
4) Efficiencies of engines and microturbines may increase in the future.
5) Emissions of the existing PGF engines was discussed. It may be desirable to operate them at 800 kW ea. vs. 600 kW presently to meet emissions requirements. However, this might not be necessary until the primary treatment facilities are on line because there is insufficient load now at fully use 1,600 kW.
6) The City is considering the fee associated with operating the IPS engines when they run out of compliance, because is has a plan to replace them in the near future.

8. **SUSTAINABILITY CONSIDERATIONS**

a. **Discussion**

1) The City did a study to determine if there would be a community benefit to have the WPCP produce power for the City (beyond the power needs of the WPCP). Photovoltaics and wind were considered. Photovoltaics on the landfill site are not an option. Photovoltaics can be considered on the plant site but only for rooftops of new buildings. Rooftop location on digesters is not an option (classified area-code).
2) “Floatovoltaics” could be considered in the pond area now and in the future.
3) Envision. Envision is a sustainability system that provides sustainability certification for the types of facilities that will be implemented at the WPCP (horizontal infrastructure). The cost to obtain this certification is similar for Leadership in Energy and Environmental Design (LEED). It would cost about $25,000 to have the WPCP design evaluated and certified plus the cost of documentation for the application (perhaps another $50 - 75,000). Construction costs might be higher for an Envision certified facility and costs vary depending on the desired certification level (bronze, silver, etc.). It was noted that it cost about $60,000 to get LEED certification for a small lab building.
4) Envision and LEED certifications. Certifications should be considered in how we set up the design standards. The City has adopted standards to achieve LEED Gold status, whether or not the buildings are submitted for certification. It is a “checklist” standard.
5) The City may need to reserve some space for photovoltaics. This can be addressed later, once the ponds are not an active treatment process. There may be too much risk associated with operating a solar power system when the ponds are still an active treatment process. The City decided that such a power system would be constructed, operated and maintained by a third party, not by the City.

Prepared By:

Dave Reardon and Katy Rogers

KR:JD:kr

Presentation Agenda

1. Energy Balance
2. Standby Power
3. Power Generation Alternatives (Cogeneration)
4. Electrical Distribution
5. Heat Recovery from Cogeneration: Activated Sludge
6. Air Permitting
7. Sustainability Considerations
8. Summary/Recommendations

2

This ECHP workshop will be a success if …

- Agree on an approach for predicting future energy production potential (i.e. biogas, FOG)
- Establish criteria for establishing standby power needs
- Establish future cogeneration alternative
- Establish approach for new electrical distribution system
- Identify potential alternatives for excess heat

3

City Staff – Issues to Consider

- Consider dual feed from PG&E
- Dual electrical distribution for process units
- Distribute 4160 V throughout the plant
- Pipe chases with grating (where appropriate traffic rated) and open raceways. Eliminate buried conduit and conductors wherever possible
- Utilize the heat generated, for both heating and cooling/chillers
- Optimize use of new CHP (i.e. use of natural gas to generate power)

4

1. Energy Balance: 2012 Existing Plant Electrical Information

1. ***Cogen Production*** 1,087 kW (natural gas augmentation)
2. ***Net Import from PG&E*** 73 kW
3. ***Total Plant Consumption*** 1,160 kW

5

Future Plant Load Summary – Definition of Criteria

Critical Standby	Power system for Facilities that require continuous operation for the reasons of public safety, emergency management, national security, or business continuity.
Normal Standby	Power system for facilities that require continuous operation to maintain the process for minimum treatment of influent.
Estimated Peak Duty Load	Maximum electrical load that will operate to meet peak process demand.
Estimated Connected Load	Sum of all electrical loads connected to the electrical system.

6

Summary of Future Plant Loads – 2035 (Horsepower)

Process	Critical Standby Load	Normal Standby Load	Est. Peak Duty Load (All Duty Units)	Est. Connected All Units (Duty & Standby)
Headworks	1,493	1,493	1,782	2,285
Primary Sed	65	105	105	200
EQ Emergency Storage	0	0	60	90
Conventional Activated Sludge	0	758	1,673	2,070
MBR	0	1,793	3,168	3,593
Filtration	100	350	351	467
Disinfection	67	134	484	901
Recycled Water System	0	0	427	594
Thickening	25	89	187	282
Digestion	0	77	544	614
Dewatering	0	0	386	532
Support Facilities	50	101	201	251
Total for AS	**1,800**	**3,107**	**6,200**	**8,286**
Total for MBR	**1,800**	**4,142**	**7,695**	**9,809**

7

2013 Biogas Production

Digester Gas Production:	161,000 cfd
*Landfill Gas Production:	289,000 cfd
Total	450,000 cfd

*Conversion of landfill gas to equivalent digester gas: 384,000 cfd @ 415 BTU = 289,000 @ 550 BTU

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Future Biogas Production from Biosolids Digestion Only*

Year	AAF or MMF	cfd
2025	AAF	196,000
	MMF	237,000
2035	AAF	209,000
	MMF	254,000

** Based on 13 cf/#VS destroyed*

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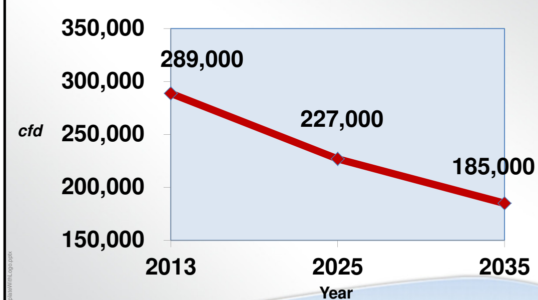
Future Landfill Gas Production*



*Gas quantities converted to 550 BTU/cf gas (assumes 2% per year reduction in landfill gas per SCS)

10

Fats, Oil, and Grease (FOG)*

100 T/year = 54,000 cfd

*Kennedy report

Total Biogas Production (cfd)

Year	AAF or MMF	Biosolids	Landfill Gas	FOG	Total
2025	AAF	196,000	227,000	54,000	477,000
	MMF	237,000	227,000	54,000	518,000
2035	AAF	209,000	185,000	58,000	452,000
	MMF	254,000	185,000	58,000	497,000

Notes:

- 475,000 cfd Biogas can generate approximately 1,200 kW @ 38% electrical efficiency
- Plant will consume approximately 1,800 kW in 2025 (activated sludge)

12

Enhancing Biogas Production

- Improve Primary Clarifier Performance
- WAS and/or Primary Sludge Pretreatment
- Thermophilic or TPAD

13

Biogas Impacts from Improving Primary Clarifier Performance

- Strategic baffling
- 10-12% increase in SS removal (use 10%)
- Total potential increase in biogas production ~11,000 cfd

Negligible increase – insufficient to make an impact on CHP sizing

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WAS Pretreatment Options

- Mechanical or Pressure Related Treatment
- Electrical Treatment
- Chemical Treatment
- Ultrasound Treatment
- Thermal Hydrolysis

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WAS Pretreatment Caveats

- Wild performance claims made by manufacturers
- Energy and chemical consumption are often understated by vendors
- Often, energy and chemical costs won't cover value of increased biogas production
- Consider only after piloting

This technology needs to mature for at least 5 years before consideration

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Biogas Impacts from Thermophilic Digestion or TPAD

- Approximately 5% increase in VS destruction
- Total increase in biogas production ~10,000-12,000 cfd
- Not sufficient enough biogas increase to affect additional heat used for digestion

Consider in future if class A Biosolids are needed

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Energy Balance Summary

- **Today:** Plant consumes ~ 1,160 +/- kW and is energy neutral
- **By 2025:** Plant will consume ~ 1,800 +/- kW and have biogas to produce ~ 1,200 +/- kW
- WAS pretreatment technology is not mature and could be reconsidered in 5 years
- Landfill gas production will continue to decline at a rate of approximately 2% per year

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2. Standby Power

NEC (Article 708) Requirement

- Critical equipment stand by power must be provided by diesel generator
- 72 hour fuel storage

Electrical Reliability Standards and Redundancy Criteria

- EPA Publication “Design Criteria for Mechanical, Electrical and Fluid System and Component Reliability”
- No single equipment failure can cause 50 percent of process to fail
- Redundant electrical system
  - Dual path for primary voltage conductors
  - Dual transformers for major process areas
  - Double ended switchgear
  - Separate MCCs in each facility, plant load divided between the MCCs

Standby Power Planning Considerations

- Reliability /redundancy standards
- Onsite power generation vs. dual PG&E feeds
- Standby power for headworks and existing plant

Summary of Future Plant Loads – 2035 (Horsepower)

Process	Critical Standby Load	Normal Standby Load	Est. Peak Duty Load (All Duty Units)	Est. Connected All Units (Duty & Standby)
Headworks	1,493	1,493	1,782	2,285
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Conventional Activated Sludge	0	758	1,673	2,070
MBR	0	1,793	3,168	3,593
Filtration	100	350	351	467
Disinfection	67	134	484	901
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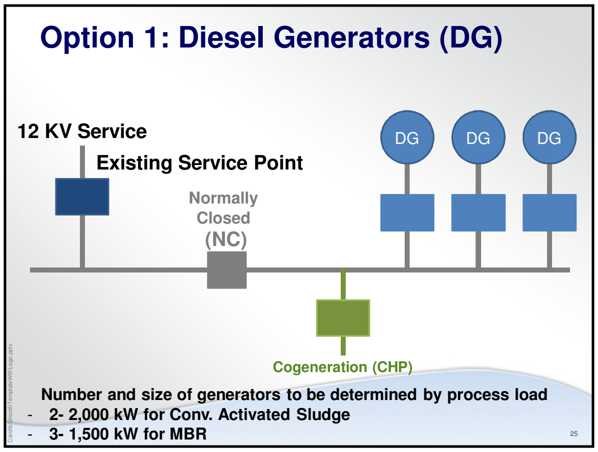
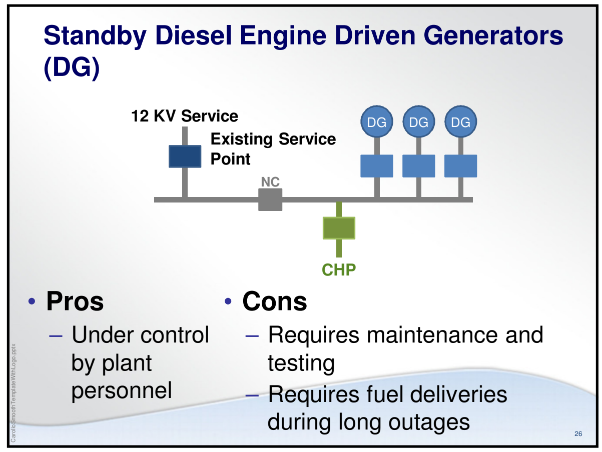
Dewatering	0	0	386	532
Support Facilities	50	101	201	251
Total for AS	**1,800**	**3,107**	**6,200**	**8,286**
Total for MBR	**1,800**	**4,142**	**7,695**	**9,809**

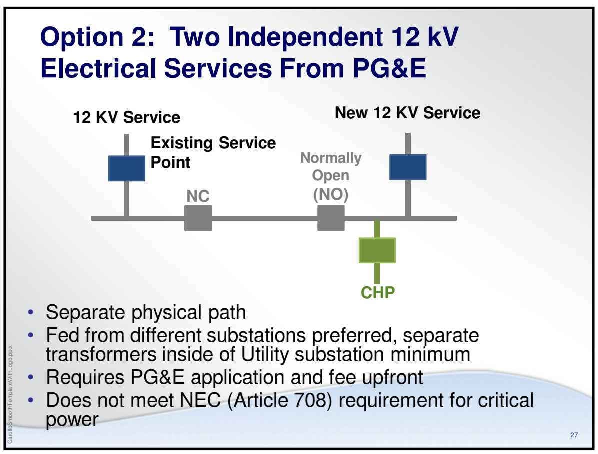
Standby Power: Two Options Considered

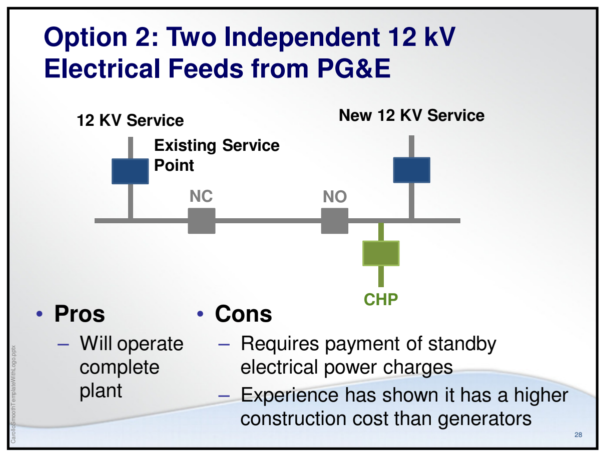
Standby Diesel Engine Driven Generators

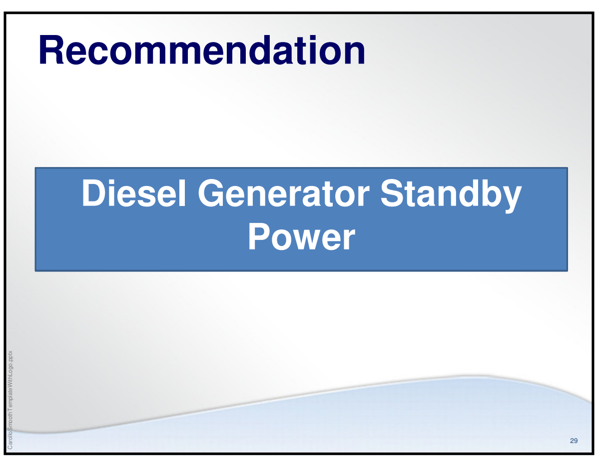
Two Independent 12 KV Electrical Services from PG&E

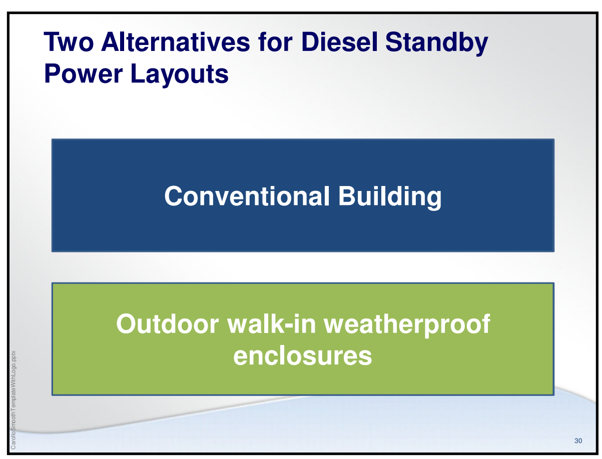

Option 1: Diesel Generators (DG)
12 KV Service
Existing Service Point
Normally Closed (NC)
DG
DG
DG
Cogeneration (CHP)
Number and size of generators to be determined by process load
- 2- 2,000 kW for Conv. Activated Sludge
- 3- 1,500 kW for MBR
25


Standby Diesel Engine Driven Generators (DG)
12 KV Service
Existing Service Point
NC
DG
DG
DG
CHP
• Pros
– Under control by plant personnel
• Cons
– Requires maintenance and testing
– Requires fuel deliveries during long outages
26

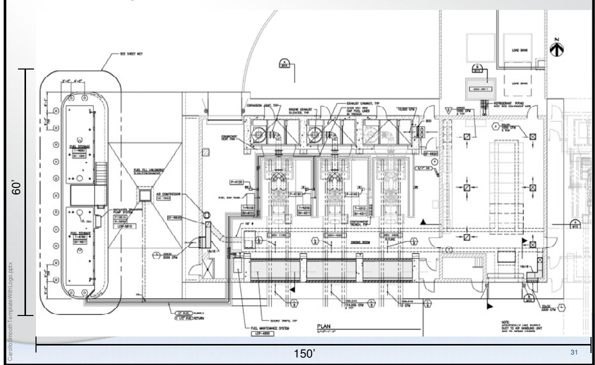

Option 2: Two Independent 12 kV Electrical Services From PG&E
12 KV Service
New 12 KV Service
Existing Service Point
Normally Open (NO)
NC
CHP
• Separate physical path
• Fed from different substations preferred, separate transformers inside of Utility substation minimum
• Requires PG&E application and fee upfront
• Does not meet NEC (Article 708) requirement for critical power
27


Option 2: Two Independent 12 kV Electrical Feeds from PG&E
12 KV Service
New 12 KV Service
Existing Service Point
NC
NO
CHP
• Pros
– Will operate complete plant
• Cons
– Requires payment of standby electrical power charges
– Experience has shown it has a higher construction cost than generators
28


Recommendation
Diesel Generator Standby Power
29


Two Alternatives for Diesel Standby Power Layouts
Conventional Building
Outdoor walk-in weatherproof enclosures
30

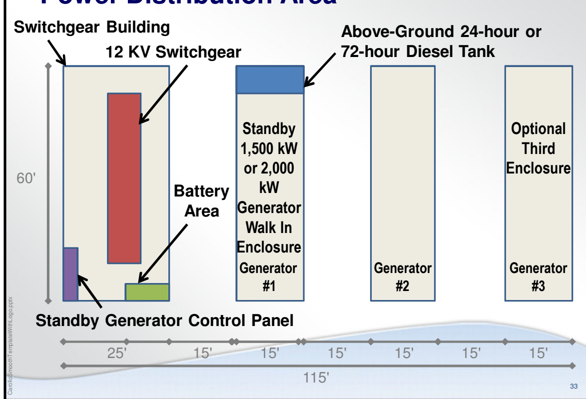
Conventional Building Layout for Standby Power



Outdoor Generator (2 MW)

75 dba @ 23 feet

Power Distribution Area



Standby Power Construction Cost (4500 kW)

Component	Conventional Building	Outdoor (walk-in enclosure)
Generator Building 3,750 sf @ $300/sq ft	1,125,000	---
Outdoor Generator Pad & Enclosure 3ea @ $150,000	-----	$450,000
Switch Gear Building 1500 sq ft @ $200/sq ft	$300,000	$300,000
Generator Cost (1500 kW ea) 3 ea @ $700,000	$2,100,000	$2,100,000
Switch Gear Cost	$1,200,000	$1,200,000
Total	$4,725,000	$4,050,000

Comparison of Standby Power Enclosure Alternatives

	Conventional Building	Outdoor (walk-in enclosure)
Reliability	+	+
Capital Cost	–	+
Ease of Operation/Maintenance	+	0
Operating Cost	0	0
Site Efficiency	+	0
Design Cost	–	+
Construction Phasing	0	+

+ Better | 0 Neutral | – Worse

Standby Power - Transition to New Electrical Service

- Initially existing distribution stays in place
- New 12 KV switchgear will subfeed existing 4,160 volt system thru transformer (provides standby power to 4,160 volt system)
- As projects take existing facilities off line, the 4,160/480 volt equipment will be removed
- New facilities in the area of the existing plant will be fed from a new 12 KV distribution system with new transformers to step it down to 480 volt
- Eventually, the 4,160 volt system will be removed

Black Start and Island Mode Operational Capabilities

Existing

- Resumption of operations after power failure
- Disconnect cogeneration from PG&E system
- Standby generator starts (supports influent pumps or cogeneration system)
- Upon return of power, plant is brought back online using an "open" transition

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Black Start and Island Mode Operational Capabilities

Proposed

- Resumption of operations after power failure
- Disconnect cogeneration from PG&E system
- Generators start within 30 to 60 seconds
- 12 kV circuit breakers open
- Generator Control System bring generators online
- Generator Control System closes 12 kV circuits in sequence
- Process Control System will bring process systems online in a predefined sequence
- Process will not start "all at once" – large loads will be started in steps
- Upon return of power, plant is brought back online using a "closed" transition, plant will not shutdown during transition

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3. Combined Heat and Power (CHP*) Alternatives (Cogeneration*)

*** Power generation onsite using biogas and/or natural gas and using waste heat for process/building heating**

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Planning Considerations

- Technology Options
- Sizing and use of natural gas
- Permitting
- Existing Cogen to be retired in 8-10 years

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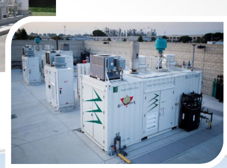
Options for CHP at Sunnyvale

Engines

Microturbines



Fuel Cells

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CHP Equipment Available Sizes, Emissions, Efficiencies

Engines (Jenbacher)
- 312 – 633 kW, 38% eff
- 412 – 852 kW, 39.2% eff
- 416 – 1,147 kW, 39.1% eff

34 ppmv NOx

Microturbines (Capstone)
- CR600 – 600 kW, 33% eff
- CR800 – 800 kW, 33% eff
- CR1000 – 1,000 kW, 33% eff

9 ppmv NOx

Fuel Cells (Fuel Cell Energy)
- DFC300 – 300 kW, 45% eff
- DFC1500 – 1,400 kW, 45% eff
- DFC3000 – 2,800 kW, 45% eff

1 ppmv NOx

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Internal Combustion Engines

Pros
- Long history at plant
- Lowest first cost
- Good efficiency
- Good heat available
- Large service network
- Competitive procurement
- Companies with sound finances
- Low fuel pressure requirements

Cons
- Higher emissions
- Medium O&M cost
- More staff involvement in maintenance

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Microturbines

Pros	Cons
Lower emissions	Higher first cost
Lower O&M	Only one manufacturer
Decent efficiency	Not a great track record on biogas
Good heat available	Higher parasitic losses (higher pressure fuel)

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Fuel Cells

Pros	
Lowest emissions	Highe[illegible]t cost
Highest efficiency	Only one manufacturer
	Not a great track record on biogas
	Higher parasitic losses
	Less plant familiarity
	Lowest heat available
	[illegible]est gas co[illegible]ing require[illegible]

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Possible CHP Facility Sizing Options

Configuration	Comments
2-633 kW Engines (1,266 kW)	Possible flaring of biogas at peak flows.
2-848 kW Engines (1,696 kW)	Natural gas augmentation needed?
2-1,059 kW Engines (2,118 kW)	Can eliminate PG&E purchases with natural gas augmentation.
2-600 kW Microturbines (1,200 kW)	Possible flaring of biogas at peak flows.
3-600 kW Microturbines (1,800 kW)	Natural gas augmentation needed?
2-1,000 kW Microturbines (2,000 kW)	Possibly eliminate PG&E purchases with natural gas augmentation.

Notes:
- **475,000 cfd Biogas can generate approximately 1,200 kW @ 38% electrical efficiency (no NG)**
- **Plant load will be 1,800 kW in 2025 (activated sludge)**

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Options for CHP Ownership and Operation

- City own and operate
- City own, private O&M
- Public-private partnership: Private financing, City purchases electricity & heat, City owns when financing is paid back
- City sells raw gas, purchase heat & electricity from third party

City own and operate is preferred by O&M staff

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Cost Information 1,700 kW IC Engine CHP

	No NG	With NG
Operating Output	1,200 kW	1,700 kW
Capital Cost (2020)	$9,500,000	$9,500,000
Yearly Gross Revenue @ 15¢/kWh	$1,500,000/yr.	$2,200,000/yr.
Yearly Gross Revenue @ 20¢/kWh	$2,000,000/yr.	$2,900,000/yr.
Yearly O&M Costs	$315,000/yr.	$315,000/yr.
Yearly Fuel (Natural Gas) ($6/MMBTU)*	----	$225,000/yr.
Yearly Net Revenue @ 15¢/kWh	$1,185,000/yr.	$1,660,000/yr.
Yearly Net Revenue @ 20¢/kWh	$1,685,000/yr.	$2,360,000/yr.
Present Worth of Savings (15¢/kWh)**	$16,000,000	$23,000,000
Present Worth of Savings (20/kWh)**	$23,000,000	$32,000,000

***NG @ $12/MMBTU Decreases PW of Savings by $3,000,000**
****4% Discount Rate, 20 yr.**

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Cost Information 1,800 kW Microturbines CHP

	No NG	With NG
Operating Output	1,000 kW	1,800 kW
Capital Cost (2020)	$11,800,000	$11,800,000
Gross Revenue @ 15¢/kWh	$1,250,000/yr.	$2,250,000/yr.
Gross Revenue @ 20¢/kWh	$1,670,000/yr.	$3,000,000/yr.
O&M Costs	$315,000/yr.	$315,000/yr.
Yearly Fuel (Natural Gas) ($6/MMBTU)*	----	$375,000/yr.
Net Revenue @ 15¢/kWh	$935,000/yr.	$1,560,000/yr.
Net Revenue @ 20¢/kWh	$1,355,000/yr.	$2,310,000/yr.
Present Worth of Savings (15¢/kWh)**	$13,800,000	$21,000,000
Present Worth of Savings (20/kWh)**	$28,000,000	$31,000,000

***NG @ $12/MMBTU Decreases PW of Savings by $5,000,000**
****4% Discount Rate, 20 yr.**

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Evaluation of Cogeneration Alternatives

	IC Engines	Microturbines
Capital Cost	0	–
Operating Cost	0	0
Efficiency	+	0
Parasitic Loads	+	0
Gas Treatment Requirements	0	0
Reliability Using Biogas	+	–
Air Permitting Issues	–	+

+ Better **0 Neutral** **– Worse**

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Cogeneration Recommendations

Today: IC engines

2020: IC engines or microturbines depending on air permitting, efficiency and reliability considerations

Size: 1,700-2,100 kW

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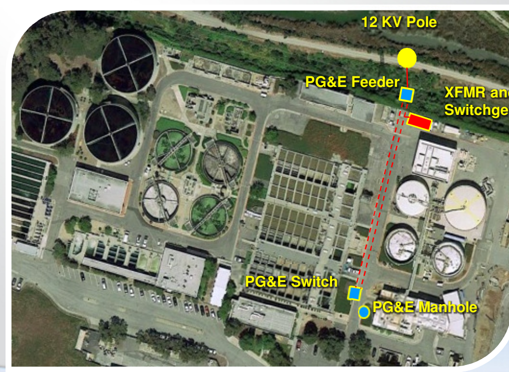
4. Electrical Distribution



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Planning Considerations

- Distribution voltage
- Primary distribution configuration
- Secondary systems configuration
- Phasing of electrical distribution system construction

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Electrical Distribution System - Existing Plant Service

- Existing is 4,160 volt with distribution system
- Replace PG&E service and transformer when main 12 kV distribution system is installed
- Remove and replace existing MCCs as areas are either updated or taken off line
- PG&E communication and scheduling

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Two Future Distribution System Configuration Options

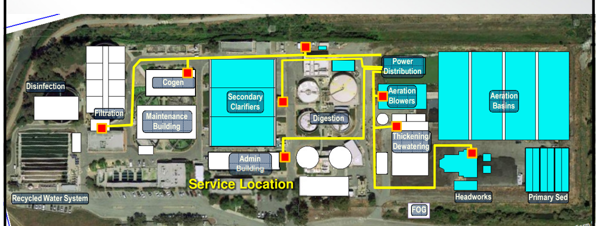
Radial

Loop

Recommended Plant Distribution Voltage is 12kV Versus 4.16 kV

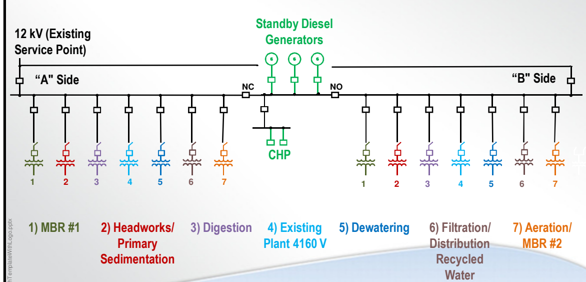
1. 12 kV distribution eliminates two main transformers (saves ~ 2% losses)
2. 12 kV and 4.16 kV technically equivalent
3. 12 kV can use smaller conductor sizes
4. 12 kV reduces number of circuits required

Primary Radial System for Conventional Activated Sludge (12kV)

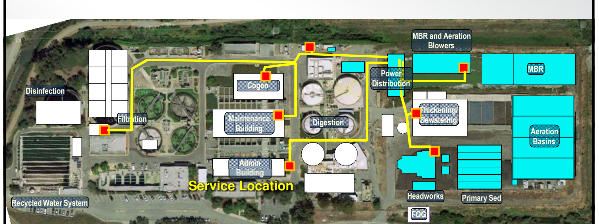


Notes: Ductbanks are separated by minimum 5', but are installed parallel to each other

Primary Radial Selective System with Secondary Selective System



Primary Radial System for MBR (12kV)



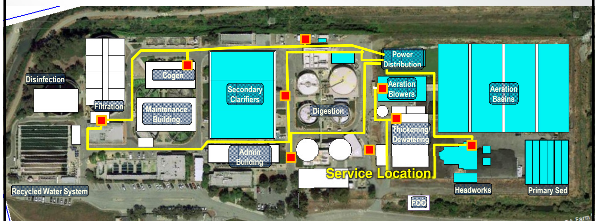
Notes: Ductbanks are separated by minimum 5', but are installed parallel to each other

Pros and Cons

Pros
- More reliable than simple radial system
- Switchgear can be fed from either primary source
- Quick restoration of service if transformer or feeder fails
- Can be built in phases, one feeder at a time

Cons
- Additional conductors and duct banks are required than loop system, higher cost

Primary Loop System for Conventional Activated Sludge



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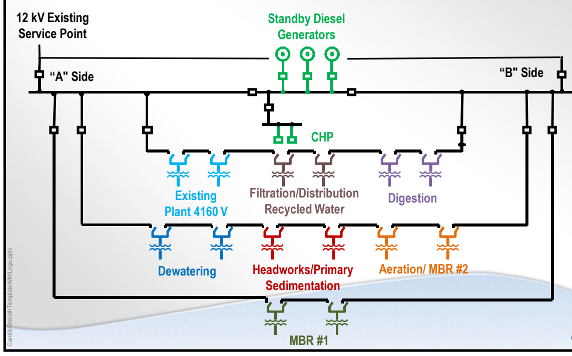
Primary Loop System with Secondary Selective System



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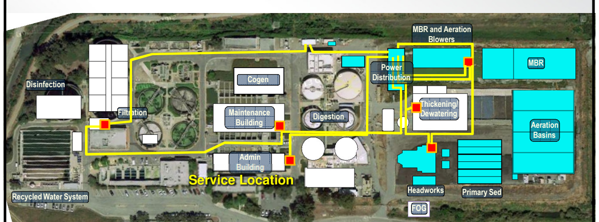
Primary Loop System for MBR



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Pros and Cons

Pros
- More reliable than simple radial system, transformers can be fed from two different paths
- High reliability
- High flexibility in case of feeder failure
- Lower cost than radial primary selective system

Cons
- Conductors are larger sizes than radial system
- Loop must be built complete (phasing considerations)

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Comparison of Plant Electrical Power Distribution Configurations

	Radial	Loop
Capital Cost	–	+
Operating Cost	0	0
Site/Corridor Issues	0	0
Safety	0	0
Reliability	0	0
Phased Construction Considerations	+	–

+ Better | 0 Neutral | – Worse

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Loop vs. Radial Cost Difference

Loop

Component	Cost
Ductbanks & conductors (3,160 ft. x $300/ft.)	$948,000
Switches (22 x $35,000)	$770,000
Total	**$1,718,000**

Radial

Component	Cost
Ductbanks & conductors (5,700 ft. x $300/ft.)	$1,710,000
Additional CB's at SWG	$400,000
Total	**$2,110,000**

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Recommendation

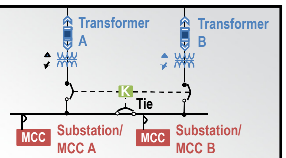
Loop System Because of Lower Cost

Secondary Distribution

Secondary Selective System
- Switchgear/MCC are tied together thru a tie-circuit breaker
- Transformers/MCC's sized for total load
- Operator can select which feeder to use to feed facility

Simple Radial System
- 50% of the facility load is on each independent transformer/MCC
- Transformer/MCC sized for 50% of facility load
- Operator cannot change configuration upon failure

Secondary Selective System



Note: Split loads between transformers

Pros	Cons
• More reliable than simple radial • Substation A & B both have a backup source for failure on primary side • Quick restoration of service if one of the transformers fails • More flexibility for maintenance	• Cost more than simple radial • Cost is higher because transformers must be sized larger to carry load of Substation A & B • Cost is higher because busses in substation must be sized to carry load of Substation A & B • With larger transformers, the short circuit fault is higher

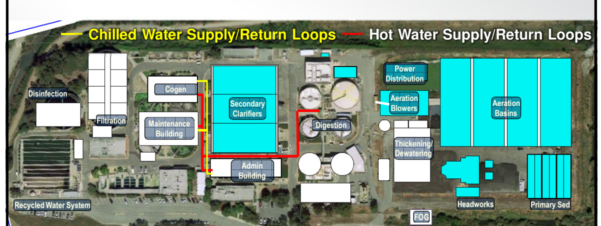
Secondary Simple Radial

Pros	Cons
• Less expensive	• Single point of failure • No redundancies

Recommendation

Secondary Selective System Because of Higher Reliability

5. Heat Recovery from Cogeneration: Activated Sludge



Heat Balance (1,700 kW CHP)

	Heat Load Location	Heat Loads
1	Recoverable Heat @ 1,200 kW	4,000,000 BTUH
2	Recoverable heat @ 1,700 kW	5,700,000 BTUH
3	Digester Heating	
	• 2035 Max Month Solids (45,000 lbs./day @ 4.5%)	1,500,000 BTUH
	• Environmental Losses	300,000 BTUH
	• Total Digester Heating	1,800,000 BTUH
4	Building Heat (Peak) (18,000 SF @ 40 BTU/SF)	720,000 BTUH
5	Excess Heat for Other Buildings or uses such as biosolids drying	1,500,000 – 3,200,000 BTUH

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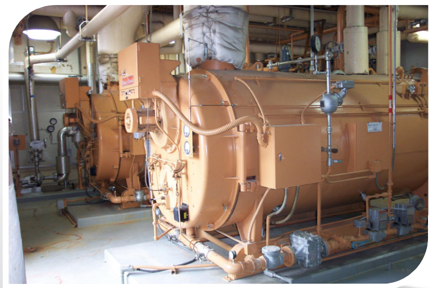
Alternate Heat Sources



Dual Fuel Boiler

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Recommendations for Waste Heat Recovery

1. Process heating for anaerobic digesters
2. Building heat for new Administration Building and Maintenance Building
3. Other buildings to be determined
4. Standby boiler - natural gas and biogas

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6. Air Permitting

- BAAQMD requirements
  - Engines
    - 70 ppmv NOx
    - 2000 ppmv CO
  - Turbines
    - 50 ppmv NOx
  - BACT – Engines
    - Oxidation catalyst for CO reduction
    - SCR for NOx reduction now required

In the future, engines may require continuous emissions monitoring systems

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7. Sustainability Considerations

- Photovoltaics
  - Rooftop units for new buildings are possible
  - Locating at adjacent landfill appears undesirable
  - “Floatovoltaics” in pond area is possible
- Energy and chemical optimization
- Being a good neighbor and public access
- Envision certification of new facilities

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8. Summary/ Recommendations

1. Provide onsite standby power 4 – 4.5 MW in building or individual enclosures
2. Provide cogeneration with IC engines or microturbines ~ 1,700 kW – 2,100 kW capacity
3. Provide redundant 12 kV power distribution
4. Provide cogeneration heat recovery to heat digesters, administration, and maintenance buildings
5. Provide secondary selective system (at MCCs) to increase reliability

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APPENDIX B – DIGESTER HEATING AND BUILDING HEAT OPTIONS WHEN IPS ENGINES ARE DECOMMISSIONED

Route

carollo in association with HDR

Interoffice Memorandum

To: Jamel Demir, Carollo

From: Dave Reardon, HDR

Date: July 10, 2014,
updated September 3
2014

Subject: Digester Heating and Building Heat Options when IPS Engines are Decommissioned

INTRODUCTION

When the engines in the primary control building are decommissioned, the sole source of heat for digesters and all buildings will be the power generation facility (PGF). Currently, process heat is provided for the hot water loop system by heat recovered from the engines in the primary control building (raw sewage pump engines) using jacket and exhaust heat recovery as well as from the PGF. A total of 0.8 MMBTUH can be provided by two primary control building engines. Jacket water heat recovery for the PGF can provide approximately 1.9 MMBTUH (both engines operating). As indicated in Table 1 below, the heat load is anticipated to be 2.5 MMBTUH. Therefore, the existing PGF facility will not be able to provide heat needs for the next 10 years. The PGF engines currently do not have exhaust heat recovery that could add a total of 4 MMBTUH (both engines operating).

Estimated peak heating loads (using recovered heat) are shown below.

Table 1 Heat Loads
Master Plan and Primary Treatment Design
City of Sunnyvale

Heat Load Location	Heat Load (BTUH)
Digester Heating	
2025 Max Month Biosolids Flow of 140,000 gpd	1,500,000
Envelope Losses	300,000

Table 1	**Heat Loads Master Plan and Primary Treatment Design City of Sunnyvale**
Heat Load Location	**Heat Load (BTUH)**
Total Digester Heat Load	1,800,000
Building Heat Load (Administration, Maintenance)	700,000
Total Heat Load	2,500,000

HEAT RECOVERY ALTERNATIVES COSTS AND DISCUSSION

The following heat recovery alternatives are being considered for operation for the next 10 years. Table 2 summarizes short term, relatively inexpensive alternatives that could be implemented before the influent engines are decommissioned. They do not involve providing new engine generators for CHP. Table 3 summarizes additional alternatives that require replacement of the existing engines sequentially or together. Modifications to the engines as outlined in the alternatives in Table 2 involve modifying the existing PGF facility rather than constructing a new CHP facility.

Table 2	**Costs for Heat Recovery Alternatives That Do Not Require Replacing Existing PGF Engines Master Plan and Primary Treatment Design City of Sunnyvale**
Alternatives Description	**Opinion of Estimated Construction Cost, (2014)**
1. Provide gas treatment, updated PGF controls; exhaust heat recovery for 2 engines, no boiler.	$3,165,000
1A. Same as 1 without gas treatment or new controls.	$1,432,000
2. Exhaust heat recovery for 2 engines, no controls updates, no gas treatment, natural gas boiler and building. Note: adding controls and biogas treatment will add approximately $ 1.6 million to Alternatives 2 and 3.	$2,316,000
3. Same as Alternative 2 above except dual fuel boiler.	$2,483,000

Table 3	Costs for Alternatives That Require Replacement of the Existing PGF Engines Sequentially or Together Master Plan and Primary Treatment Design City of Sunnyvale
Alternatives Description	**Opinion of Estimated Construction Cost, (2014)**
4. One new 800-900 kW engine in existing PGF building with emissions control after-treatment, new controls for one existing engine, exhaust heat recovery and gas treatment for two engines. No backup boiler. A second new engine will be added at a later time as needed.	$5,634,000
5. 2 new 800-900 kW engines in existing PGF building complete with jacket and exhaust heat recovery, gas treatment, emissions control after-treatment and no boiler.	$8,286,000

Alternative 1: Provide gas treatment, updated PGF controls; exhaust heat recovery for two existing engines, no boiler. This alternative provides updated controls and gas treatment to extend the life of the PGF engines. The facility can provide enough recovered heat if one engine is down. However, if the entire cogeneration system is down, no recovered heat can be produced. This situation appears to be rare but we do not have documentation of frequency or duration of this type of event. If an event of this type lasted for about one week, process performance (and perhaps biosolids regulatory compliance) of the digesters would be compromised. Alternatives 1 and 1A heat recovery reliability can be increased by adding a boiler in the third bay of the existing PGF building at additional cost.

Alternative 1A: Same as Alternative 1 without gas treatment. This alternative has the advantage of being the lowest cost solution but with all of the disadvantages listed in Alternative 1 plus the PGF system will be potentially less reliable and more costly to operate and maintain than Alternative 1 because gas cleaning is not provided.

Alternative 2: Exhaust heat recovery for two existing engines, natural gas boiler and building, no controls updates, no gas treatment,. This has the advantage of being a low cost solution that simply adds exhaust heat recovery and a backup NG boiler. No controls upgrades or gas treatment would be provided. Another advantage is that this provides the most robust backup for heat recovery in the event that the PGF facility is down for an extended time period (say a week or more). One disadvantage is that the new boiler (and building) for Alternatives 2 and 3 requires additional footprint at the plant and space may be at a premium. Alternatives 2 and 3 do not include gas treatment and controls upgrades, thus making the PGF system potentially less reliable and more costly to operate and maintain than Alternative 1. Gas treatment and controls may be needed for Alternatives 2 and 3 if City wants existing PGF engines to last another 10 years without excessive O&M and reliability issues. Adding gas treatment and controls improvements to Alternatives 2 and 3 will add approximately $1.6 million.

Alternative 3: Same as Alternative 2 above except dual fuel boiler. See discussion for Alternative 2 above. The chief advantage of this alternative compared to Alternative 2 is the benefit of being able to use digester gas in the boiler when an engine is down, thereby avoiding additional costs of using natural gas if digester gas is available.

Alternative 4: One new 800-900 kW engine in existing PGF building, new controls for one existing engine, exhaust heat recovery and gas treatment for two engines, no boiler. Advantages include new equipment (one new engine generator) that will reduce O&M costs, higher electrical efficiency, and better parts availability for the new unit. Disadvantages include unpredictable costs for modifications to existing PGF facility, high construction cost and potential sequencing issues which could require the need to shut down part or all of the PGF facility during construction with attendant loss of power production revenue. Adding a backup boiler and building (to assure heat availability if the entire PGF facility is down) will add approximately $800,000 to this alternative.

Alternative 5: Two new 800-900 kW engines in existing PGF building complete with jacket and exhaust heat recovery, new emissions system, gas treatment, no boiler. Advantages include new equipment that will reduce O&M costs, higher electrical efficiency, and better parts availability. Disadvantages include unpredictable costs for modifications to existing PGF facility, very high construction cost and potential sequencing issues which could require the need to shut down part or all of the PGF facility during construction with attendant loss of power production revenue. Adding a backup boiler and building (to assure heat availability if the entire PGF facility is down) will add approximately $800,000 to this alternative. Note that the present worth of the cogeneration system described in the ECHP TM (constructed in 2020) is approximately $8.4 million

DISCUSSION AND RECOMMENDATIONS

Alternatives 4 and 5 are very expensive and require a significant investment in the existing PGF building. HDR feels that they are too risky and expensive to be considered further now. Alternatives 4 and 5 can still be considered later. Alternatives 1, 1A, 2, and 3 are less expensive and each has its advantages and challenges. HDR, Carollo, and CDM staff discussed the alternatives on July 9, 2014 and concluded that alternative 1 appears to be in the best interest of the City. Further discussions between Carollo Engineers and the City led to a decision to postpone gas cleaning. A comparison of the alternatives is presented in Table 4 below.

HDR recommends Alternative 1A (new PGF controls, and exhaust heat recovery for the two existing PGF engines with no backup boiler) because:

1. Increased heat recovery reliability and life expectancy for the PGF facility if gas cleaning is added in 1-2 years

2. Moderate cost

3. Elimination of need for separate boiler building

Table 4 Qualitative Comparison of Alternatives
Master Plan and Primary Treatment Design
City of Sunnyvale

	1. Provide gas treatment, updated PGF controls, exhaust heat recovery for 2 engines, no boiler.	1A. Same as 1 without gas treatment.	2. Exhaust heat recovery for 2 engines, natural gas boiler and building, no controls updates, no gas treatment.	3. Same as 2 except dual fuel boiler.	4. One new 800-900 kW engine in existing PGF building, new controls for one existing engine, exhaust heat recovery and gas treatment for two engines. No backup boiler.	5. 2 new 800-900 kW engines in existing PGF building complete with jacket and exhaust heat recovery, gas treatment, and no boiler.
Reliable Heat Availability	0	0	+	+	0	0
Capital Cost	0	+	0	0	-	-
Ease of O&M	0	-	-	-	+	+
Operating Cost	0	-	-	-	+	+
Site Efficiency	+	+	-	-	+	+
Construction Risk/Sequencing	0	+	+	+	0	-

+ More attractive 0 Neutral - Less attractive