City of San José

San José/Santa Clara Water Pollution Control Plant Master Plan

TASK NO. 5
PROJECT MEMORANDUM NO. 3
ENERGY EVALUATION

FINAL DRAFT
August 2011

in association with

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CITY OF SAN JOSÉ

SAN JOSÉ/SANTA CLARA WATER POLLUTION CONTROL PLANT MASTER PLAN

TASK NO. 5
PROJECT MEMORANDUM NO. 3
ENERGY ALTERNATIVES

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PLANT MASTER PLAN

GLOSSARY OF ACRONYMS AND TERMS

AB	Assembly Bill
AC	Acre
ACH	Air Changes per Hour
AD	Air Drying
ADAF	Average Day Annual Flow (Average daily flow or loading for an annual period)
ADC	Alternative Daily Cover
ADMMF	Average Day Maximum Month Flow (Peak month for each year)
ADMML	Average Day Maximum Month Load
ADWF	Average Dry Weather Flow (Average of daily influent flow occurring between May - October)
ADWIF	Average Dry Weather Influent Flow (Average of five consecutive weekday flows occurring between June - October)
ADWL	Average Dry Weather Load
AES	Advanced Energy Storage
ANSI	American National Standards Institute
ARWTF	Advanced Recycled Water Treatment Facility
BAAQMD	Bay Area Air Quality Management District
BAB2E	Bay Area Biosolids to Energy
BACWA	Bay Area Clean Water Association
BAF	Biological Aerated Filter
BC	Brown and Caldwell
BCDC	Bay Conservation and Development Commission
BNR	Biological Nutrient Removal
BNR1	Formerly Secondary Facilities
BNR2	Formerly Nitrification Facilities
BOD	Biochemical Oxygen Demand
BTUs	British Thermal Units

CAG	Community Advisory Group
CAL OSHA	California Occupational Safety and Health Administration
CAMBI	Vendor name for a pre-processing technology
CARB	California Air Resources Board
CCB	Chlorine Contact Basin
CEC	California Energy Commission
CEPT	Chemically Enhanced Primary Treatment
CEQA	California Environmental Quality Act
CFM	Cubic feet per minute
CH_4	Methane
CH_3SH	Methyl mercaptan
CIP	Capital Improvement Program
City	City of San José
CL	Covered Lagoons
CO	Catalytic Oxidation
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalence
CSI	California Solar Incentive
DAFT	Dissolved Air Flotation Thickener
DO	Dissolved Oxygen
DG	Digester Gas
DPH	Department of Public Health
D/T	Dilutions to threshold
EBOS	Emergency Basin Overflow Structure
EDCs	Endocrine Disrupting Compounds
EEC	Environmental Engineering and Contracting, Inc.
e.g.	For example
EIR	Environmental Impact Report
ELAC	Engineering, Legal, and Administrative Costs

EPA	United States Environmental Protection Agency
EQ	Equalization
ESD	Environmental Services Department
etc	etcetera
Fe_2O_3	Ferric Oxide
Fe_2S_3	Ferric Sulfide
FIPS	Filter Influent Pump Station
FOG	Fats, Oils, and Grease
fps	foot per second
FRP	Fiberglass Reinforced Plastic
FWS	Food Waste Separation
GC/SCD	Gas Chromatograph/Sulfur Chemiluminescence Detector
GHG	Greenhouse Gas Emissions
gpd/ft^2	Gallons per Day per Square Foot
GWP	Global Warming Potential
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HOCl	Hypochlorous Acid
HP	Harvest Power
HRT	Hydraulic Residence Time
HVAC	Heating Ventilation and Air Conditioning
HW	Headworks
IMLR	Internal Mixed Liquor Return
IWA	International Water Association
ISCST3	Industrial Source Complex Short-Term 3
ITC	Investment Tax Credit
JEPA	Joint Exercise of Power Authority
L	Liter
LFG	Landfill Gas

LHV	Lower Heating Value
MAD	Mesophilic Anaerobic Digestion
MBR	Membrane Bioreactor
MD	Mechanical Dewatering
MG	Million Gallons
mgd	Million Gallons per Day
mg/L	Milligrams per Liter
MLE	Modified Ludzack - Ettinger
MLSS	Mixed Liquor Suspended Solids
MM	Million
MOP	Manual of Practice
MSW	Municipal Solid Waste
MW	Mega Watt
NAS	Nitrification with Anaerobic Selector
NBB	Nitrification Blower Building
NFPA	National Fire Protection Association
NG	Natural Gas
NH_3	Ammonia
N_2O	Nitrous Oxide
NPDES	National Pollutant Discharge Elimination System
OCMP	Odor Control Master Plan
O&M	Operations and Maintenance
ORP	Oxidation-Reduction Potential
OUR	Oxygen Uptake Rate
PE	Primary Effluent
PEPS	Primary Effluent Pump Station
PG&E	Pacific Gas and Electric
PHWWF	Peak Hour Wet Weather Flow (Peak hour flow resulting from a rainfall event)
PM	Project Memorandum

PMP	Plant Master Plan
PPA	Power Purchase Agreement
ppbv	Parts per billion by volume
PPCD	Pounds per capita per day
ppmv	Parts per million by volume
PPP	Public-Private Partnerships
PS	Primary Sludge
PV	Photovoltaic
QA/QC	Quality Assurance/Quality Control
RAS	Return Activated Sludge
RO	Reverse Osmosis
RPS	Renewable Portfolio Standard
ROAP	Regional Odor Assessment Program
RSPS	Raw Sewage Pump Station
SBB	Secondary Blower Building
SBR	Sequencing Batch Reactor
SBWR	South Bay Water Recycling
SC	Santa Clara
SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
SGIP	Self-Generation Incentive Program
SJ	San Jose
sf	Square Feet
SOM	Skidmore, Owings, and Merrill
SOTE	Standard Oxygen Transfer Efficiency
SRT	Solids Residence Time
SS	Suspended Solids
SSPS	Settled Sewage Pump Station
SVI	Sludge Volume Index

TAD	Thermophilic Anaerobic Digestion
TAG	Technical Advisory Group
TBL	Triple Bottom Line
TM	Technical memorandum
TN	Total Nitrogen (organic & inorganic forms which are ammonia, nitrates, nitrite)
TSS	Total Suspended Solids
TWAS	Thickened Waste Activated Sludge
UV	Ultraviolet
VFDs	Variable Frequency Drives
VOC	Volatile Organic Compound
VSL	Volatile Solids Loading
WAS	Waste Activated Sludge
WEF	Water Environment Federation
WPCP	Water Pollution Control Plant
WWTP	Wastewater Treatment Plant

1.0 INTRODUCTION/SUMMARY

1.1 Introduction

The purpose of this project memorandum (PM) is to summarize current and future energy use and production and develop alternatives and recommendations for short-term and long-term energy management at the San José/Santa Clara Water Pollution Control Plant (WPCP) for the WPCP Plant Master Plan (PMP). This PM identifies both onsite and offsite opportunities that the WPCP can pursue to meet both their own internal energy management goals and the broader Green Vision outlined in the City of San José's (City's) Strategic Energy Plan.

The technologies presented in this PM include those commonly used in the wastewater industry (either in North America or Europe), along with technologies that are considered innovative and are undergoing further improvements/development. These more innovative technologies must also exhibit promising features and have examples of full-scale experience at facilities similar to the WPCP. Processes that are at the research stage of development will not be included in the alternative analysis or in the costs for the recommended implementation plan presented in this PM, since it is premature to determine if these processes are suitable at the scale of the WPCP. However, many of the recommendations presented herein will not be implemented for a number of years. Therefore an updated technological assessment, which could include pilot testing, should be performed as part of the early implementation stages of each project before final selection of a process or equipment is made.

1.2 Summary

The elements of the recommended phased plan include the following:

- Completion of the process optimization, automation, and efficiency improvement efforts that have already been started.
- Conducting energy audits on a regular basis to identify additional, cost-effective opportunities and implement recommended measures.
- Installation of a 1 MW solar photovoltaic (PV) Power Purchase Agreement (PPA).
- Installation of a 1.4-MW fuel cell Power Purchase Agreement (PPA).
- Upgrade of the existing engines fuel system to operate without supplemental natural gas (NG).
- Development of a detailed energy strategic plan.

- Installation of higher efficiency cogeneration equipment or additional fuel cells.
- Installation of additional solar PV systems.
- Pursuit of additional feedstocks such as fats, oils and grease (FOG), and food waste to enhance digester gas production.
- Implementation of the proposed digester upgrades recommended in PM 5.2.
- Consideration of a high-pressure DG storage facility as part of the solar projects.
- Pursuit of municipal solid waste (MSW) integration possibilities.
- Further investigation of chemically enhanced primary treatment (CEPT).
- Further investigation of algae technologies, beginning with a grant funded pilot project.

Detailed descriptions of these projects, along with implementation timelines and planning level project cost estimates, are provided in PM 6.1 CIP Implementation. The costs provided in this PM are for comparison of alternatives only, and should not be used for CIP planning.

The modifications to the plant are shown on the following updated simplified process flow schematic, entitled "Future WPCP Process Flow Schematic."

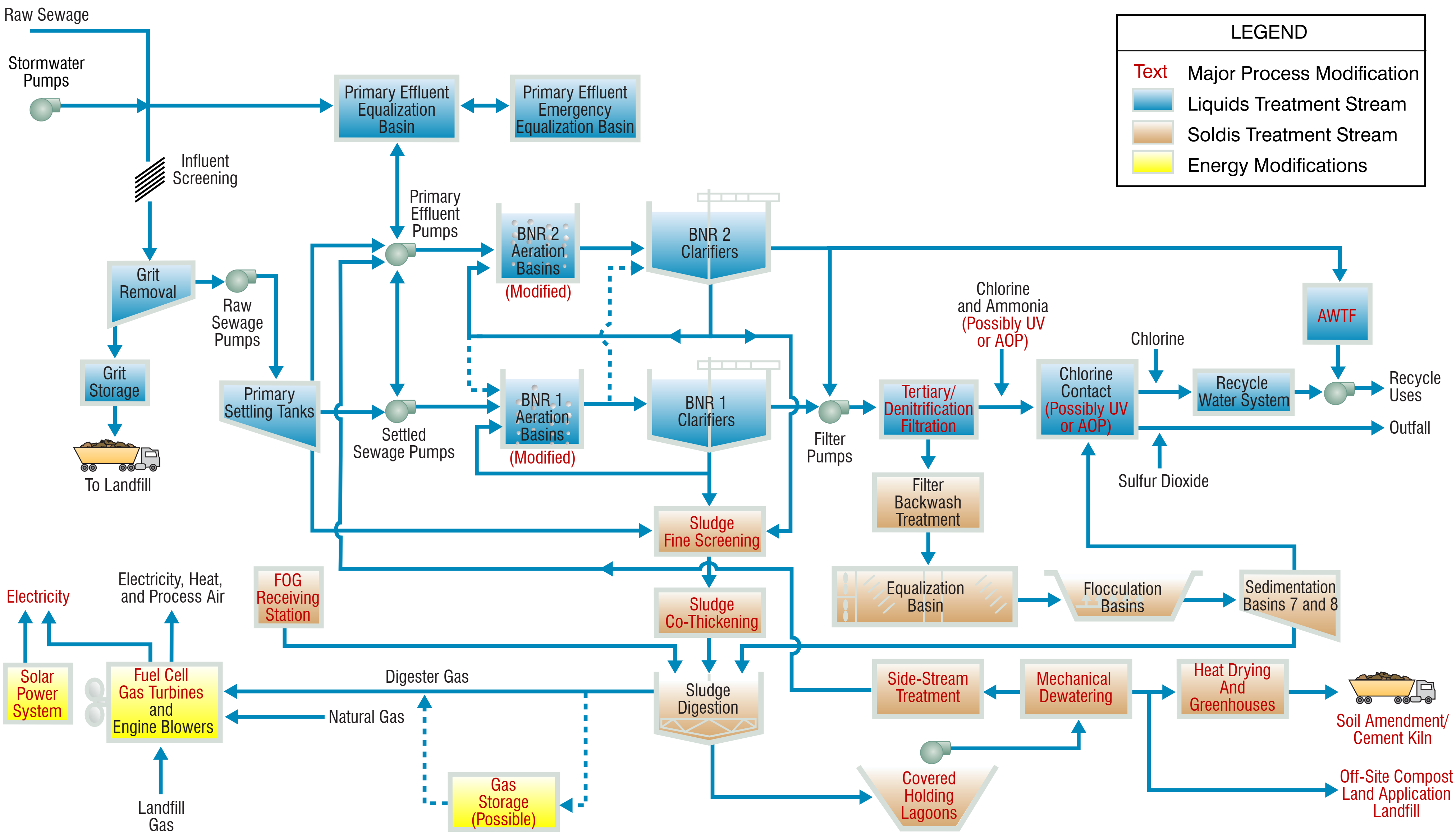
2.0 BACKGROUND

2.1 Planning Triggers

Energy management improvements are driven by a number of current and future factors that will act as triggers for implementing various projects.

Six categories of potential triggers for the Plant Master Plan (PMP) projects include the following:

- **Condition (Rehabilitation/Replacement)** – A *condition trigger* is assigned if the process or facility has reached the end of its economic useful life. This trigger is established based on the need to maintain that facility as operationally sufficient to meet mission critical reliability and performance requirements.
- **Regulatory Requirement** – A *regulatory trigger* is assigned when the need is driven by local, state or national regulatory requirements.
- **Economic Benefit** – An *economic benefit trigger* is assigned when a positive reduction in life-cycle costs (considering capital and O&M) can be achieved.



FUTURE WPCP PROCESS FLOW SCHEMATIC
SAN JOSE/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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- **Improved Performance Benefit** – An improved *performance benefit trigger* is assigned when there is a benefit in improved operations and maintenance performance related to overall reliability and/or to reduced operational and safety-related risks.
- **Increased Flows/Loads** – An *increased flow and load trigger* is assigned when the need is based on an increase in capacity to accommodate increases in flows or loads into the WPCP.
- **Policy Decision** – The *policy trigger* is assigned when the reason is based on a management and/or political decision from the policy-makers with the City.

2.2 Overall Energy Management Approach

Development of a strategic vision and supportive policies is critical to responding to the various planning triggers quickly and successfully.

The City must have an overall energy management approach with strategies that focus both inward toward energy opportunities at the WPCP and outward toward opportunities through external sources. Having this diversified strategy will provide the City with flexibility to select from a variety of opportunities allowing them to dynamically respond to different triggers that may occur during the next 30 years. Figure 1 illustrates the proposed overall energy management approach.

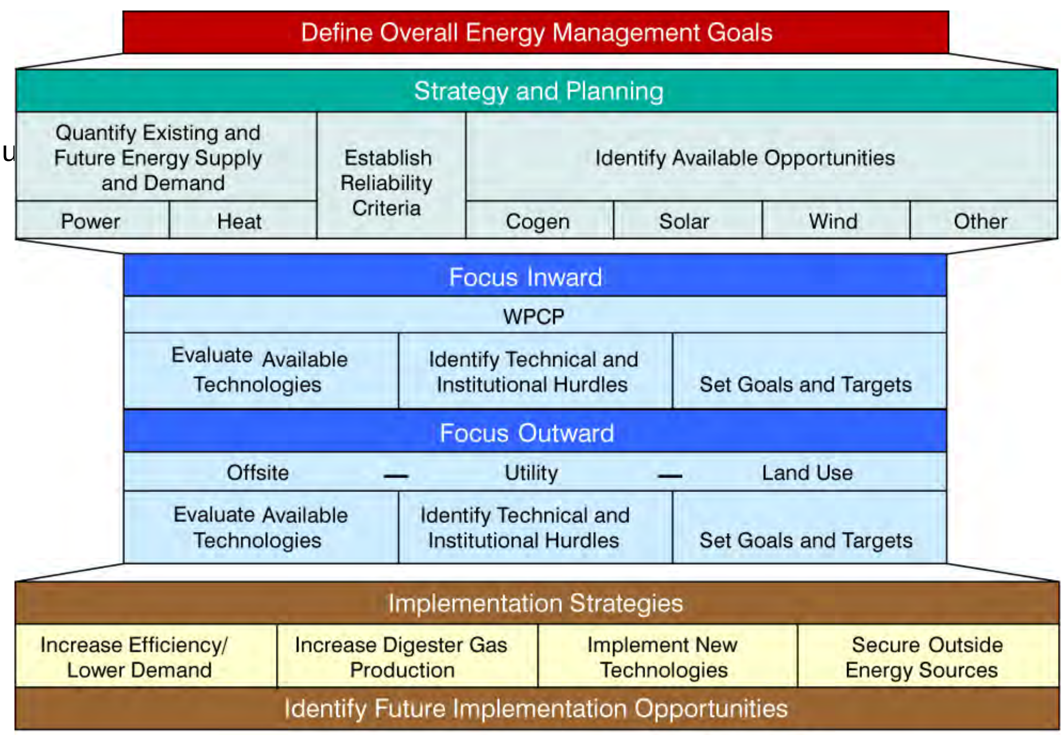

Figure 1
OVERALL ENERGY MANAGEMENT APPROACH
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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The organization of this PM is based on the proposed energy management approach. Specifically, the following sections have been included from Figure 1:

- Defining overall energy management goals that improve sustainability, reliability and operations
- Strategy and Planning of use of existing and future energy and heat resources
- Focus Inward (WPCP process area) on being green, achieving self-sufficiency
- Focus Outward (surrounding land use areas around the WPCP), to develop renewable energy adjacent to the plant, once the inward focus objectives have been met
- Implementation Strategies/Recommendations for immediate, near-term and long term projects

2.3 WPCP Energy Management Goals

As part of the Environmental Services Department (ESD) Vision, the WPCP has identified four main goals for their energy management plan. These goals include:

- Being green by preserving energy, recycling and reducing waste
- Achieving energy self-sufficiency
- Optimizing operating costs for the WPCP facilities
- If feasible, look into exporting power

Each of these main goals represents a commitment to improving the operation and reliability of the WPCP, while at the same time becoming more sustainable and reducing overall energy costs. As part of the self-sufficiency goal, the WPCP is looking to reduce energy usage by 17 percent by 2012 and achieve self-sufficiency by 2022.

2.4 City of San José Energy Management Goals

Similarly, the City of San José has developed ten Green Vision goals to achieve environmental, ecological, and economic sustainability through new technology and innovation by the year 2022. While many of these goals are broader reaching, there are several that have a direct correlation to energy management at the WPCP including goals to:

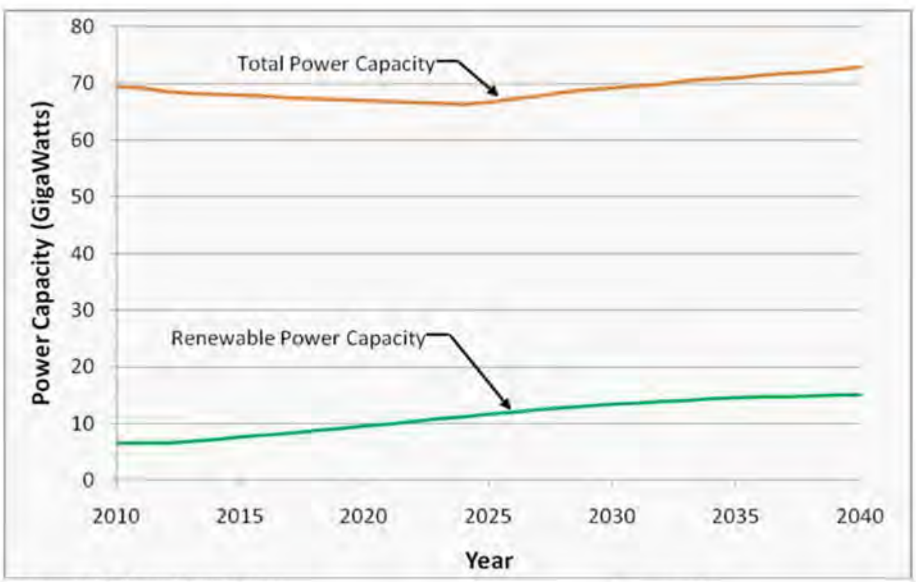
- Reduce per capita energy use by 50 percent
- Receive 100 percent of electrical power from clean renewable sources
- Build or retrofit 50 million square feet of green buildings
- Divert 100 percent of the solid waste from landfill and convert waste-to-energy
- Recycle or beneficially use 100 percent of wastewater

2.5 Benefits of Going Green

As indicated in the City of San José's Strategic Energy Plan[1], there are a variety of reasons for addressing the City's energy needs through green policies. In addition, law makers and regulators throughout the State have begun to implement mandatory policies to guide California toward greener energy solutions.

In 2002, California Governor Gray Davis signed Senate Bill 1078 into law, requiring California to generate 20 percent of its electricity from renewable energy, as defined by the California Energy Commission (CEC) and California Public Utilities Commission (CPUC), no later than 2017. This Renewable Portfolio Standard (RPS) was amended in 2006 by Senate Bill 107 to accelerate the deadline to meet the 20 percent requirement to December 31, 2010. Then, in March of 2009, Senate Bill 14 was passed which enabled the CPUC to raise the previous cap on how much renewable energy must be bought or built by investor owned utilities from 20 percent to 33 percent by 2020.

As a result of these policies, electric generating capacity from renewable sources is expected to increase dramatically in the future. Forecasting data provided by IHS Global Inc. indicates that electric generating capacity from renewable sources will more than double by 2040, accounting for nearly the entire total power capacity increase through that period. Based on the CPUC's latest cap increase it is likely that this renewable power capacity forecast could be even higher. Figure 2 provides a summary of the forecasting data for the Pacific region (California, Hawaii).



Source: IHS Global Insight, Inc.

Figure 2
ELECTRIC GENERATING CAPACITY FORECAST (CALIFORNIA/HAWAII)
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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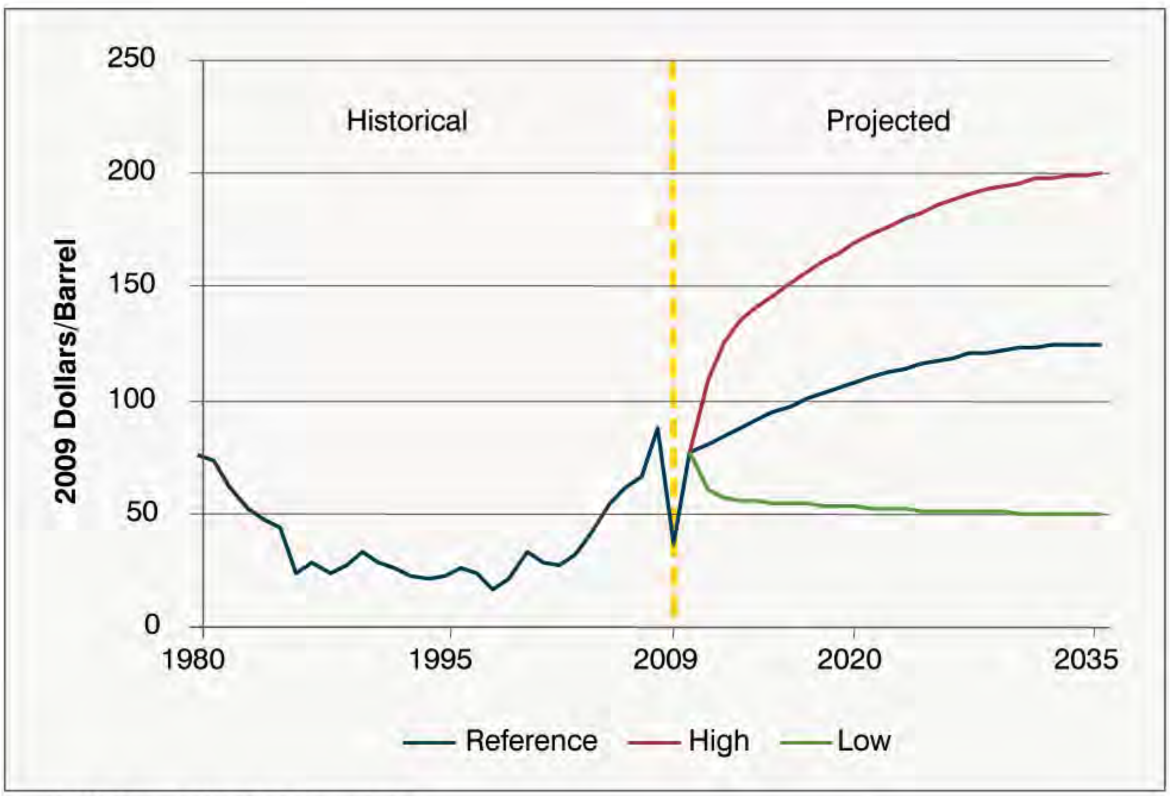
[1] Strategic Energy Plan 2022, City of San José, June 2009.

In addition to the aforementioned social and environmental benefits, there is also a future economic benefit to using green energy as opposed to traditional petroleum-based energy (electric power and natural gas). More specifically, since there is a finite amount of petroleum, as global petroleum resources are exhausted the cost for petroleum-based power should continue to rise at a higher rate in the future. Conversely, with the infinite nature of renewable resources such as wind and sun, the cost for green power should rise at a much lower pace.

Similarly, it is anticipated that the cost of self-generation using petroleum based technologies will increase more dramatically than self-generation using green technologies due to higher sensitivity to escalating energy costs in conjunction with decreasing capital costs for implementing green technologies. Figures 3 and 4 illustrate oil and natural gas price trends and projections in 2009 year dollars generated as part of the U.S. Energy Information Administration Energy Outlook 2011, while Figure 5 shows renewable energy cost trends and projections in 2000 year dollars prepared by the National Renewable Energy Laboratory Energy Analysis Office.



Source: U.S. Energy Information Administration

Figure 3
OIL PRICE TRENDS
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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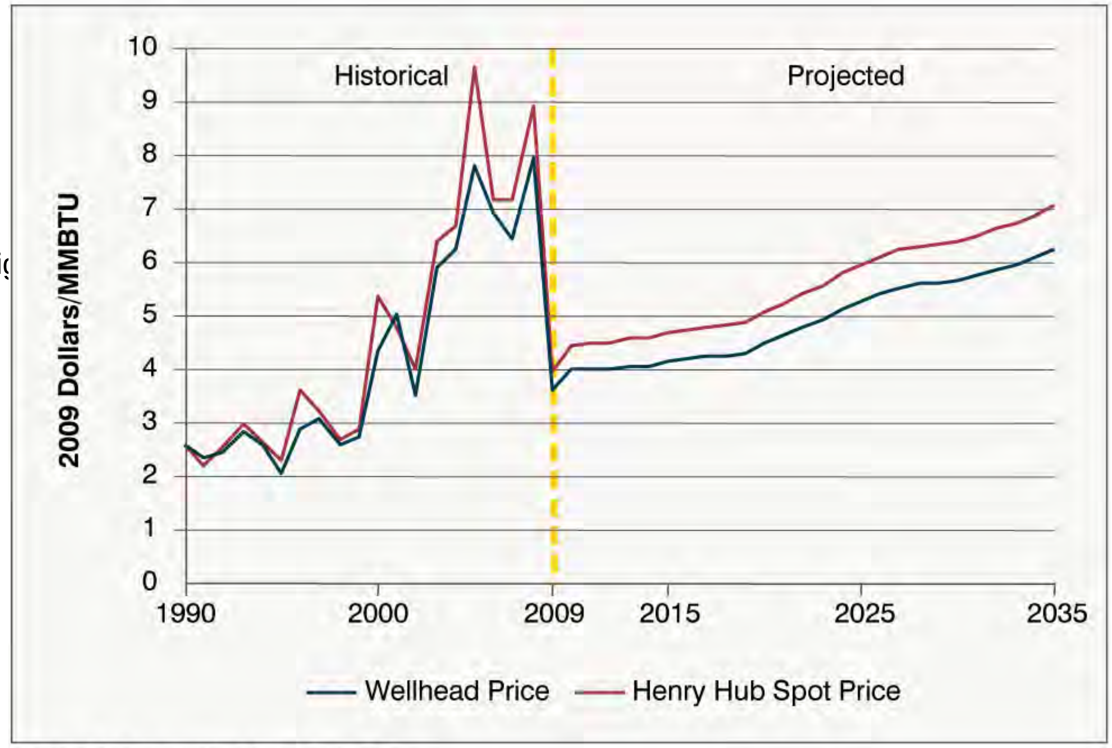

Source: U.S. Energy Information Administration

Figure 4
NATURAL GAS PRICE TRENDS
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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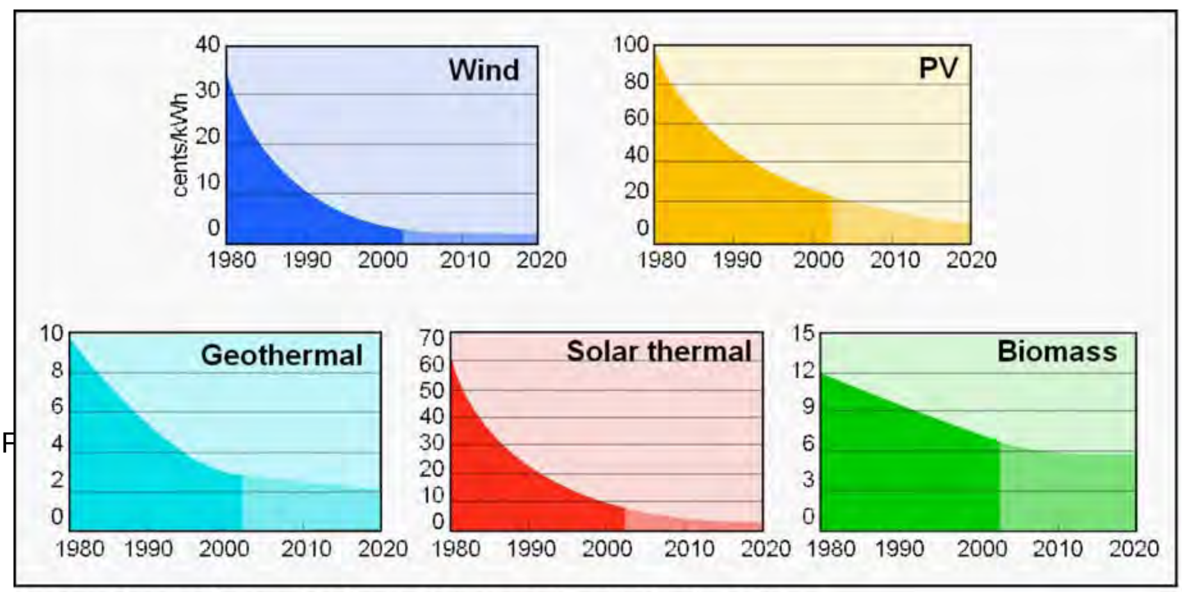

Source: National Renewable Energy Laboratory Energy Analysis Office

Figure 5
RENEWABLE ENERGY COST TRENDS
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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2.6 Regulatory Considerations

2.6.1 Greenhouse Gas Emissions

Another reason for going green is recent regulations on greenhouse gas (GHG) emissions. The California Air Resources Board (CARB) adopted the Global Warming Solutions Act (also referred to as Assembly Bill 32, AB 32) in September 2006. This Act was the first regulatory program in the U.S. to require public and private agencies statewide to reduce GHG emissions. The GHGs included under AB 32 are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases. The Act does not affect wastewater treatment process emissions, but it does cover cogeneration facilities and onsite general stationary combustion sources. CARB's Proposed Scoping Plan (released October 2008) listed two thresholds by which agencies are to check if they are required to report. The reporting thresholds shown below include combustion emissions from both fossil fuel (i.e., natural gas and diesel) and non-fossil fuel (i.e., biogas) sources.

Facilities	Reporting Year 2010	Reporting Year 2011 and Beyond
Cogeneration	≥ 1 MW and ≥ 2,500 mt[(1)] CO_2 per year	≥ 10,000 mt CO_2e[(2)] per year (Now reports as "electricity generating unit")
General Stationary Combustion	≥ 25,000 mt CO_2 per year	≥ 10,000 mt CO_2e per year

Notes:
(1) mt: metric tons.
(2) CO_2e: Carbon dioxide equivalent emissions.

In addition, the U.S. EPA's Mandatory GHG Reporting Rule (Reporting Rule) was adopted October 30, 2009. The Reporting Rule explicitly states that centralized domestic wastewater treatment systems are not required to report emissions; however, any stationary combustion of fossil fuels taking place at a wastewater treatment facility may be considered a "large" source of GHGs if they emit a total of 25,000 metric tons or more of CO_2 equivalent emissions per year.

For the WPCP, State mandatory GHG reporting applies to their cogeneration and engine-driven blower facilities since they currently use over 46 million standard cubic feet (scf) of natural gas (NG) annually to operate these systems (this is approximately the amount required to generate 2,500 metric tons of CO_2).

In the future, the WPCP will likely exceed the general stationary combustion reporting threshold due to renewable fuel usage over 916 million scf annually (this is approximately the amount of landfill gas [LFG] and digester gas [DG] required to generate 25,000 metric tons of CO_2). At that time, the City will be required to report GHG emissions for each source (e.g., engine-generators, engine-driven blowers, boilers, flares, etc.).

The CARB adopted the cap-and-trade program in December of 2010 and it becomes effective January of 2012. This program states that agencies emitting 25,000 metric tons or more of fossil fuel-based (i.e., natural gas and diesel) CO_2e emissions per year beginning in 2011 or any subsequent year will be capped and required to reduce their emissions over time. As long as the City utilizes renewable fuels and stays below this threshold, the current regulations only require the City to report GHG emissions and do not subject the WPCP to being a capped entity.

2.6.2 Bay Area Air Quality Management District Regulations

Recently, the South Coast Air Quality Management District (SCAQMD) tightened the emission limits for NO_x, VOCs and CO. Shortly thereafter, these same rules were adopted by the Central Valley air boards. It is also anticipated that the Bay Area Air Quality Management District (BAAQMD) will tighten their existing regulations in the near future to align more closely with the SCAQMD regulations. Although no date has been formally set, it is expected that these changes could be adopted as soon as 2015.

When this occurs, these more restrictive emission requirements will have a significant impact on the operation of the existing engine-generators. More specifically, the engines would need to be equipped with selective catalytic reduction (SCR) and catalytic oxidation (CO) systems or a similar technology in order to achieve the stringent emission requirements. In addition, enhanced gas conditioning systems with H_2S and siloxane removal would be required to prevent poisoning and blinding of the catalysts. Typically, a facility is given 3 to 4 years to comply.

2.7 Achieving the Overall Energy Management Goals

The WPCP is in a good position to achieve their overall energy management goals. This is because approximately 50 percent of their current power needs are being met by self-generation using available digester gas (DG) production and landfill gas (LFG) purchase. However, this is projected to decrease to only 40 percent as the power demand increases in the future due to increased flow and loads and process upgrades. The other 50% of the current energy usage comes from non-green energy sources like purchase of natural gas (NG) to augment DG and LFG, and purchased electrical power from Pacific Gas and Electric (PG&E).In addition, the existing power generation infrastructure is costly to maintain.

As a result, the WPCP will need to maximize the use of green power sources both onsite and offsite and will need to upgrade their existing cogeneration systems and add new high efficiency, low maintenance infrastructure to meet their overall energy management goals (further discussed in Section 5.0).

3.0 STRATEGY AND PLANNING

3.1 Existing Energy Demand

3.1.1 Power

The July 2009 Heat Balance Study[2] prepared by CDM (Heat Balance Study) indicated that the total WPCP electrical demand was approximately 8 MW for the 2007/2008 period.

3.1.2 Aeration Air

The Heat Balance Study also indicated that the WPCP had an aeration air demand equivalent to approximately 4 MW over the 2007/2008 period. This aeration air demand was satisfied using a combination of both engine-driven and electric blowers

3.1.3 Heat

During 2007-2008, the WPCP used an average 17 MMBTU/hr of heat to provide both process and space heating for the WPCP. The minimum and maximum month heat use was 13 MMBTU/hr and 23 MMBTU/hr respectively.

3.2 Existing Energy Supply

3.2.1 Gas

The WPCP currently uses a combination of DG, LFG purchased from the Newby Island Landfill, and NG purchased from PG&E in their existing gas utilization equipment. While the WPCP runs several boilers on NG only, the majority of the existing gas utilization equipment uses a blend of the three available gas sources. The gases are blended in certain proportions based on their respective heat content to meet utilization equipment fuel requirements. There are two blending stations at the WPCP, both located at the gas compressor building. Based on the Heat Balance Study, the stream for Blend Gas 1 (BG1) has an average composition of 34 percent DG, 41 percent LFG, and 25 percent NG. The stream for Blend Gas 2 (BG2) has an average composition of 44 DG, 33 percent LFG, and 23 percent NG.

Projections of landfill gas availability from the Newby Island Landfill are beyond the scope of this memorandum. However, landfill gas quantities typically drop off sharply after the site closes, which is planned for 2025. Based on a similar LFG modeling study completed for another facility, it is likely that the amount of LFG available in 2040 will be roughly half of that currently available and declining every year thereafter.

[2] San Jose/Santa Clara Water Pollution Control Plant Heat Balance Study, CDM, July 2009.

3.2.2 Power

The WPCP satisfies their power demands through a combination of purchased power from PG&E and through onsite generation using the BG1 and BG2 gas streams. Table 1 summarizes the current onsite electrical power generation capacity based on Appendix J of the Heat Balance Study. However the historical output indicated in Appendix A of the Heat Balance Study indicates that these capacities are not currently achieved and would require some rehabilitation of these engine-generators to achieve nameplate capacity.

Table 1 Onsite Electrical Power Generation Capacity
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Tag	Description	Location	Capacity	Year Built	Fuel Source
E-2	Engine-generator	P&E Building	800 kW	1953	BG1
E-3	Engine-generator	P&E Building	800 kW	1953	BG1
E-5	Engine-generator	P&E Building	1,750 kW	1962	BG1
EG-1	Engine-generator	Building 40	2,800 kW	1994	BG2
EG-2	Engine-generator	Building 40	2,800 kW	1983	BG2
EG-3	Engine-generator	Building 40	2,800 kW	1983	BG2

Note: Due to maintenance issues, engine-generators E-2, E-3, and E-5 are typically not in operation.

3.2.3 Aeration Air

Similarly, the WPCP satisfies their aeration air demands through a combination of electric driven blowers and gas engine-driven blowers using the BG1 gas streams. Table 2 summarizes the current onsite aeration air generation capacity based on Appendix J of the Heat Balance Study.

3.2.4 Heat

Similarly, the WPCP satisfies their heat demands through onsite heat recovery from their cogeneration equipment. Table 3 summarizes the current onsite heat recovery capacity based on historical heat output provided in Appendix A of the Heat Balance Study.

The Heat Balance Study made several recommendations to improve the efficiency and operation of the WPCP's existing heat recovery systems. For the purpose of this PM, it is assumed that at least two of the Building 40 engine heat recovery silencers will be upgraded to improve heat recovery efficiency from approximately 16 percent to 30 percent.

Table 2 Onsite Aeration Capacity
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Tag	Description	Location	Output	Year Built	Fuel Source
A-1	Engine-driven blower	Secondary Blower Bldg	2,345 hp	1962	BG1
A-2	Engine-driven blower	Secondary Blower Bldg	2,345 hp	1962	BG1
A-3	Engine-driven blower	Secondary Blower Bldg	2,345 hp	1962	BG1
A-4	Engine-driven blower	Secondary Blower Bldg	1,855 hp	1962	BG1
A-5	Engine-driven blower	Secondary Blower Bldg	1,855 hp	1962	BG1
A-6	Engine-driven blower	Secondary Blower Bldg	1,855 hp	1962	BG1
EB-1	Motor-driven blower	Building 40	4,000 hp	1983	-
EB-2	Motor-driven blower	Building 40	4,000 hp	1983	-
EB-3	Motor-driven blower	Building 40	4,000 hp	1983	-
PAB-1	Motor-driven blower	Nitrification Blower Bldg	2,250 hp	1975	-
PAB-2	Motor-driven blower	Nitrification Blower Bldg	2,250 hp	1975	-
PAB-3	Motor-driven blower	Nitrification Blower Bldg	2,250 hp	1975	-
PAB-4	Motor-driven blower	Nitrification Blower Bldg	2,250 hp	1975	-
PAB-5	Motor-driven blower	Nitrification Blower Bldg	2,250 hp	1975	-

Table 3 Onsite Heat Recovery Capacity
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Tag	Description	Location	Capacity
E-2	Engine-generator	P&E Building	1.4 MMBTU/hr
E-3	Engine-generator	P&E Building	1.4 MMBTU/hr
E-5	Engine-generator	P&E Building	0.6 MMBTU/hr
EG-1	Engine-generator	Building 40	4.7 MMBTU/hr
EG-2	Engine-generator	Building 40	4.3 MMBTU/hr
EG-3	Engine-generator	Building 40	4.3 MMBTU/hr
A-1	Engine-driven blower	Secondary Blower Bldg	0.6 MMBTU/hr
A-2	Engine-driven blower	Secondary Blower Bldg	3.4 MMBTU/hr
A-3	Engine-driven blower	Secondary Blower Bldg	0.6 MMBTU/hr
A-4	Engine-driven blower	Secondary Blower Bldg	2.3 MMBTU/hr
A-5	Engine-driven blower	Secondary Blower Bldg	2.3 MMBTU/hr
A-6	Engine-driven blower	Secondary Blower Bldg	0.4 MMBTU/hr

3.3 Future Energy Demand

3.3.1 Reliability Analysis

The WPCP is required to manage the sewage flow and provide a minimal level of treatment at all times to address public health and safety concerns. In order to protect the City from potential violations and fines from the Regional Water Quality Control Board, the WPCP must have sufficient reliable power to allow operation of critical process functions in order to meet permit requirements during a temporary utility power outage. Based on decisions made by WPCP staff, these critical process functions include:

- Wastewater pumping
- Full preliminary and primary treatment
- Primary sludge pumping to the digesters and mixing of the digester tanks
- Nitrification with Anaerobic Selector (NAS) secondary treatment (including RAS/WAS pumping)
- Hypochlorite disinfection

Under this operational scenario there will be no filtration, no reuse pumping, and no solids processing capabilities with the exception of digester mixing. This assumes a temporary outage of less than one day that is not the result of a *force majeure* event (i.e. earthquake, flood, etc.). Heating is not required during such an event and as a result has not been considered further in the reliability analysis. Table 4 provides a summary of the anticipated electrical and equivalent aeration load requirements (Critical Power Demand) to meet the reliability criteria of this operational scenario.

3.3.2 Power

As improvements to the WPCP recommended in PM 5.1, PM 5.2, and PM 5.5 are implemented, the WPCP power demand will change accordingly. These improvements include:

1. Conversion of all coarse bubble diffusers to fine bubble diffusers.
2. Transitioning 30 mgd to Ozone disinfection in 2025, increasing to 34 mgd in 2040. (Assumes advanced oxidation of only the reuse stream).
3. Co-thickening and a FOG receiving station
4. Full sludge dewatering and belt drying of 20 percent of the solids stream from 2025 onwards.
5. Odor control for the headworks, primary clarifiers, and dissolved air flotation thickeners (DAFT).

Table 4	Critical Power Demand (Approximate) San José/Santa Clara Water Pollution Control Plant Master Plan City of San José				
		Reliable Operation Demand (MW)			
Item		**2010**	**2015**	**2025**	**2040**
Onsite Demand	Headworks	0.3	0.3	0.4	0.4
	Primary Treatment	0.1	0.1	0.1	0.1
	Secondary Treatment(1)	1.2	1.3	1.4	1.6
	Aeration air(3)	4.7	4.4	4.9	5.7
	Filters	0.0	0.0	0.0	0.0
	Disinfection(2)	0.02	0.03	0.03	0.03
	Reuse Pump Station	0.0	0.0	0.0	0.0
	Solids Handling(4)	0.17	0.17	0.17	0.17
	Miscellaneous (2%)	0.13	0.13	0.14	0.16
Total		**6.6**	**6.4**	**7.1**	**8.2**

Notes:
(1) Assumes nitrification with anaerobic selector (NAS) mode of operation and does not include aeration air.
(2) Assumes HOCl disinfection in the discharge channel.
(3) Based on 50% coarse bubble diffusers and 50% fine bubble diffusers in 2010, thereafter, 100% fine bubble diffusers. 2010 aeration air is supplied to BNR2 with electric-driven blowers (approximately 2.0 MW), and to BNR1 with engine-driven blowers (equivalent to 2.7 MW), thereafter aeration air is supplied to both BNR1 and BNR2 with electric-driven blowers only. The demand values represent the aeration air demand at the one-day ammonia limit of 8 mg-N/L. Under this scenario 22% of the aeration basins are operating in non-nitrification mode, the remainder are operating as normal. The combined effluent will meet 8 mg-N/L.
(4) Digester mixing only.

Table 5 summarizes the calculated electrical demand for the planning period based on milestones presented in PM 5.1, 5.2, and 5.5. A separate demand analysis was also conducted to determine the theoretical minimum power demand for the WPCP assuming “ideal process operating conditions.” A summary of this analysis is provided in Appendix A.

3.3.3 Heat

Similarly, the average heat demand will change as process improvements are made at the WPCP. Table 6 summarizes the calculated heat demand for the planning period based on phasing milestones indicated in PM 5.1 and PM 5.2, driven primarily by the digesters. The digester phasing is as follows:

- 4 digesters upgraded and on line by 2015.
- 3 more digesters upgraded and on line by 2024.
- 3 more digesters upgraded and on line by 2027.

Table 5	Electrical Demand (Approximate) San José/Santa Clara Water Pollution Control Plant Master Plan City of San José				
		Demand (MW)			
Item		2010	2015	2025	2040
Onsite Demand	Headworks	0.3	0.3	0.4	0.4
	Primary Treatment	0.1	0.1	0.1	0.1
	Secondary Treatment	1.2	1.3	1.4	1.6
	Aeration air (1)	5.3	4.9	6.2	7.1
	Filters	0.8	0.8	0.8	1.0
	Disinfection	0.02	0.02	0.4 (3)	0.4 (3)
	Reuse Pump Station	1.0	1.5(4)	2.7 (4)	3.6 (4)
	Solids Handling	1.0	1.3 (5)	1.8 (5)	2.1 (5)
	Miscellaneous (10%) (7)	1.0	1.0	1.4	1.6
Total		**10.7 (6)**	**11.3**	**15.0**	**17.9**

Notes:
(1) Based on 50% coarse bubble diffusers and 50% fine bubble diffusers in 2010. Thereafter, 100% fine bubble diffusers. 2010 aeration air is supplied to BNR2 with electric-driven blowers (2.2 MW) and to BNR1 with engine-driven blowers (equivalent to 3.1 MW), thereafter aeration air is supplied to both BNR1 and BNR2 with electric-driven blowers only.
(2) Includes the start of a high-strength sludge dewatering stream.
(3) Includes transitioning 30 mgd to ozone disinfection in 2025, increasing to 34 mgd in 2040.
(4) Assumes reuse increasing from 15 mgd to 22 mgd by 2015, to 40 mgd in 2025, and to 54 mgd in 2040.
(5) Includes co-thickening and FOG station in 2015, full sludge dewatering and belt drying of 20 percent of the solids stream. FOG processing based on 20 percent of volatile solids loading as FOG per B&C TM 3.3 and B&C TM 4.4. Based on the revised digester upgrade implementation (4 units upgraded by 2015, 3 more upgraded by 2024 and 3 more upgraded by 2027).
(6) It is anticipated that onsite demand will drop to 10.1 MW once the remaining diffusers have been replaced.
(7) Includes odor control for the headworks, primary clarifiers and DAFTs.

Table 6	Annual Average Heat Demand San José/Santa Clara Water Pollution Control Plant Master Plan City of San José				
		Demand (MMBTU/hr)			
Item		2010	2015	2025	2040
Onsite Deman d	Building Heating	0.1	0.1	0.2	0.2
	Digester Heating	17.3	16.4	16.8	19.0
Total		**17.4**	**16.5**	**17.0**	**19.2**

3.4 Future Energy Supply

3.4.1 Reliability Analysis

In order to meet the minimum power demands for critical processes identified in Table 4, the WPCP must have adequate infrastructure in place to satisfy this critical electrical demand. It is typical for municipalities to verify the available reliable capacity by assuming one large unit out of service. In addition, for the purpose of this PM it is assumed that all P&E engine generators will be taken out of service because of their age and maintenance issues.

Since the WPCP has engine-driven generators that can be used to meet their critical electrical demand and engine-driven blowers that can be used to meet their critical aeration demand, each of these systems should be evaluated independently to confirm the reliability for each system. Therefore, the reliable onsite electric power generation capacity from the engine-generators assuming one largest unit out of service is as follows:

- Bldg 40 - Two 2,800 kW engine-generators = 5,600 kW

Total **= 5,600 kW**

Thus, the existing on-site generation infrastructure is adequate to meet the minimum electrical reliability criteria for year 2010 (3.9 MW excludes 2.7 MW engine-driven BNR1 aeration). Similarly, the reliable onsite aeration air generation capacity from the engine-driven blowers assuming one largest unit out of service is as follows:

- SBB – Three 1,855 hp engine-driven blowers = 1,380 kW each
- SBB – Two 2,345 hp engine-driven blowers = 1,750 kW each

Total **= 7,640 kW**

This further demonstrates that the existing on-site engine-driven blowers are adequate to meet the minimum aeration air reliability criteria for year 2010 (2.7 MW for BNR1 aeration). In the future, however, due to age and anticipated changes in air regulations, it is anticipated that the Building 40 engine-generators will be replaced with new generators, and the engine-driven blowers will be decommissioned. Ample aeration capacity exists with the electrical blowers in Building 40 for BNR1, and in the Nitrification Blower Building for BNR2 to meet the minimum aeration air reliability criteria. The electrical blowers are all newer than the engine-driven blowers, therefore no provision has been made for their replacement. In addition, an aeration header connection between these two sets of electrical blowers has been proposed (details in PM 5.1), which would provide further operational redundancy.

3.4.2 <u>Power</u>

Between July of 2008 and June of 2009, the WPCP generated approximately 1,450,000 scfd of DG and purchased approximately 1,180,000 scfd of LFG that was used in this existing cogeneration equipment. Based on the average heat rate of this equipment and DG and LFG lower heating values (LHV) from the Heat Balance Study, the WPCP is currently able to generate an average of 5.5 MW of power from the available DG and LFG. This “green power” production will increase with increasing influent flows and loads.

As previously demonstrated, the WPCP will be able to meet both the electrical and aeration reliability criteria for year 2010 with their existing infrastructure. However, in order to meet the minimum reliability criteria through green sources, the WPCP will need to improve the efficiency of their generation systems and increase their DG production. Table 7 provides a summary of the incremental contribution of each component for the critical power balance, while Figure 6 shows how implementation of the digester improvements recommended in PM 5.2 to generate more DG will help the WPCP get close to meeting reliability criteria through green sources. A total of ten digesters are to be upgraded in the future. Although the exact phasing of the digester improvements may change, for simplicity of presentation

Figure 6 and all subsequent power and heat graphics have assumed 45 percent of the digesters will be upgraded by 2015, 80 percent by 2025, and 100 percent by 2040.

Although the WPCP will be close to meeting the reliability criteria, it is anticipated that there will be a significant shortfall with respect to the total WPCP power demand. Replacement of existing cogeneration systems with higher efficiency technologies will reduce the shortfall slightly. However, other energy supply alternatives will need to be considered to meet the plant self-sufficiency goal. In addition, the existing agreement for purchase of landfill gas expires in 2017 and may not be economically attractive after that. Even if this contract is renewed, the LFG availability will eventually decrease after the anticipated closure of Newby Island Landfill in 2025. Table 8 shows the incremental contribution of each component for the overall power balance. Figure 7 shows the anticipated shortfall over the planning period, which ranges from 4.2 MW in 2015 to 9.8 MW in 2040.

3.4.3 Heat

Similarly, when the WPCP operates their existing cogeneration equipment to utilize all of the available DG and LFG (approximately 5.5 MW in 2010 as previously calculated), they will also be able to recover approximately 30 percent of the total energy input as heat using their lead cogeneration equipment (two Building 40 engines) after making the near term improvements recommended by the Heat Balance Study. This correlates to a heat load of approximately 17.7 MMBTU/hr. This will increase with increasing influent flows and loads as the WPCP operates both their lead and lag engine-driven blowers (Secondary Blower Building Blowers) to utilize all of the DG and LFG available.

The WPCP will have a slight surplus of heat once the digester improvements are implemented as recommended in PM 5.2. Table 9 and Figure 8 provide a summary of the incremental contribution of each of these improvements. One potential use for this surplus heat would be in a heat drying process for dewatered cake solids, however the surplus would need to be greater for this to be viable. Another potential use would be in an organic rankine cycle process to generate electricity. A more detailed description of this process is included in Appendix C of this PM.

Table 7	**Critical Power Balance San José/Santa Clara Water Pollution Control Plant Master Plan City of San José**		
		Incremental Contribution (MW)	
Item		**2010**	**2040**
Supply	DG Baseline	3.2	4.4
	LFG Baseline	2.3	1.2 [(1)]
	Digester Improvements	0.0	0.9
Supply Subtotal		**5.5**	**6.5**
Demand Subtotal (From Table 4)		**(6.6)**	**(8.2)**
Net Total		**(1.1)**	**(1.7)**

Note:
(1) Assumes LFG will be available in reduced quantities after closure of Newby Island landfill in 2025.

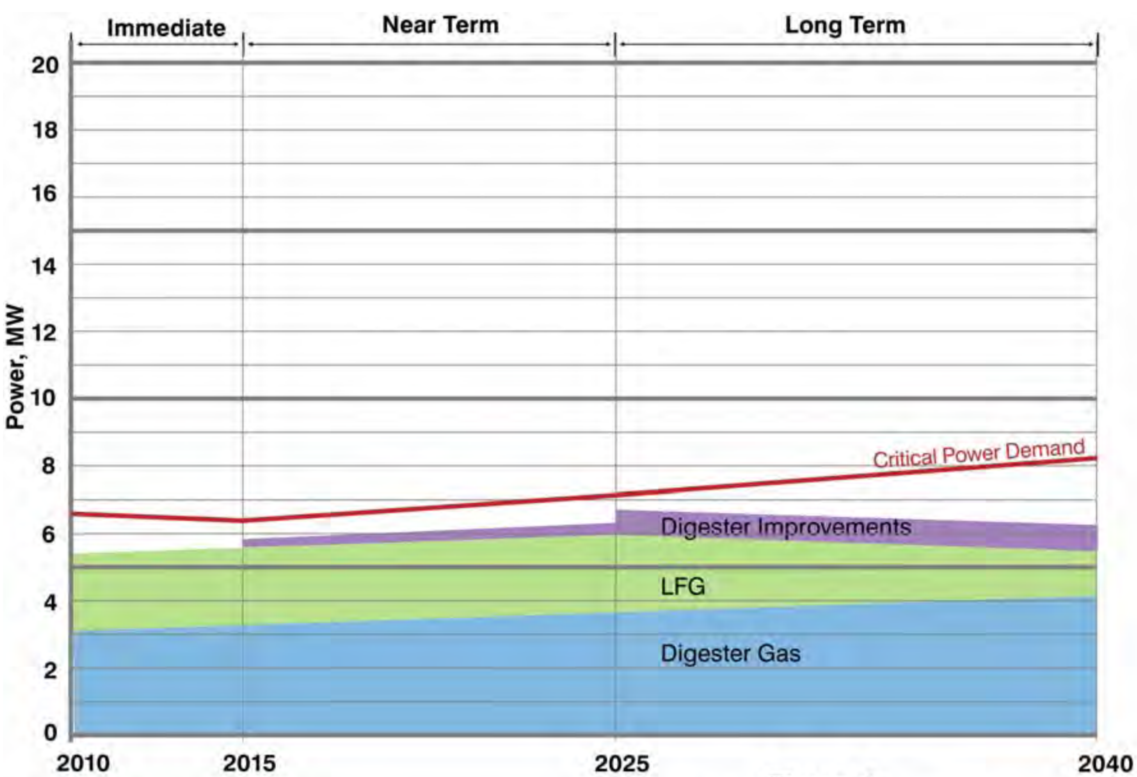

Figure 6
MEETING CRITICAL POWER DEMAND THROUGH ONSITE GENERATION
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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Table 8	Overall Power Balance San José/Santa Clara Water Pollution Control Plant Master Plan City of San José				
Item		Incremental Contribution (MW)			
		2010	2015	2025	2040
Supply	DG Baseline	3.2	3.4	3.8	4.4
Supply	LFG Baseline	2.3	2.3	2.3	1.2 (1)
Supply	Digester Improvements	0.0	0.3	0.6	0.9
Supply Subtotal		**5.5**	**6.0**	**6.7**	**6.5**
Demand Subtotal (From Table 5)		**(10.7)**	**(11.3)**	**(15.0)**	**(17.9)**
Net Total		**(5.2)**	**(5.3)**	**(8.3)**	**(11.4)**

Note:
(1) Assumes LFG will be available in reduced quantities after closure of Newby Island landfill in 2025.

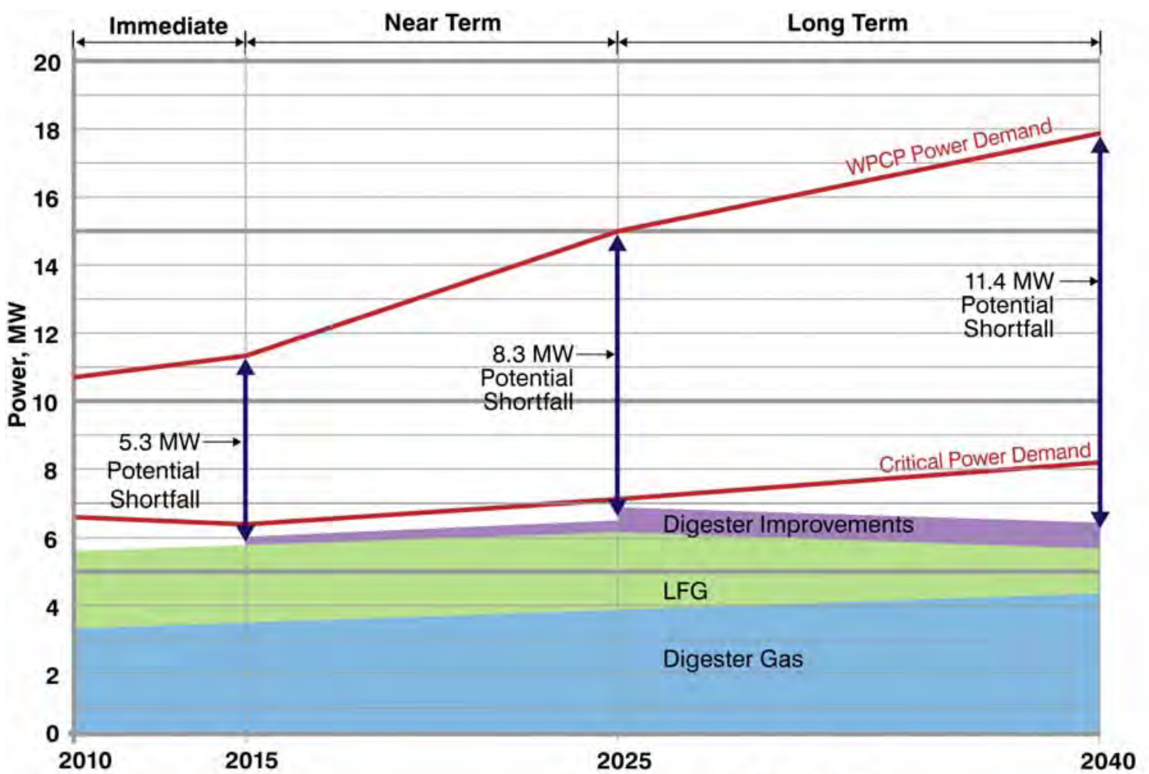

Figure 7
OVERALL POWER BALANCE FOR PLANT SELF-SUFFICIENCY
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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Table 9	Overall Heat Balance San José/Santa Clara Water Pollution Control Plant Master Plan City of San José				
Item		**Incremental Contribution (MMBTU/hr)**			
		2010	**2015**	**2025**	**2040**
Supply	DG Baseline	10.3	10.8	11.6	12.7
	LFG Baseline	7.4	7.4	7.4	3.7 (1)
	Digester Improvements	0.0	0.9	1.8	2.6
Supply Subtotal		**17.7**	**19.1**	**20.8**	**19.0**
Demand Subtotal (From Table 6)		**(17.4)**	**(16.5)**	**(17.0)**	**(19.2)**
Net Total		**0.3**	**2.6**	**3.8**	**(0.2)**

Note:

(1) Assumes LFG will be available in reduced quantities after closure of Newby Island landfill in 2025.

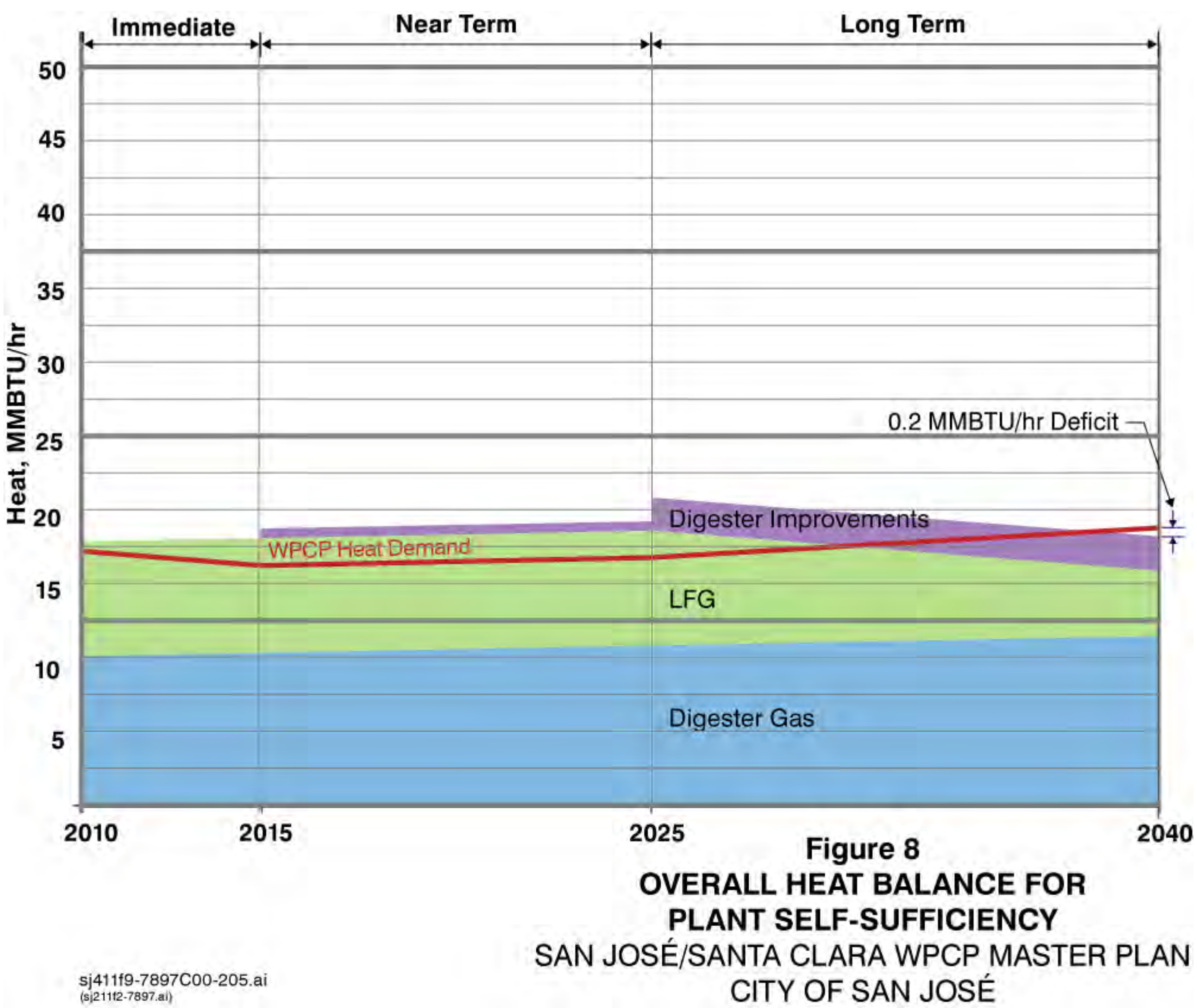

Figure 8
OVERALL HEAT BALANCE FOR PLANT SELF-SUFFICIENCY
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

It is important to note that there will be periods where the peak heat demand exceeds the amount of heat generated onsite. This is more likely during the winter when ambient temperatures are the lowest and additional heat will be required for both space and process heating. Since there will likely be surplus heat during most of the year, further analysis of potential surplus heat opportunities is warranted and should be explored as part of a more detailed energy strategic plan. Figure 9 illustrates the anticipated seasonal heating demand based on WPCP heating data from Appendix A of the Heat Balance Study.

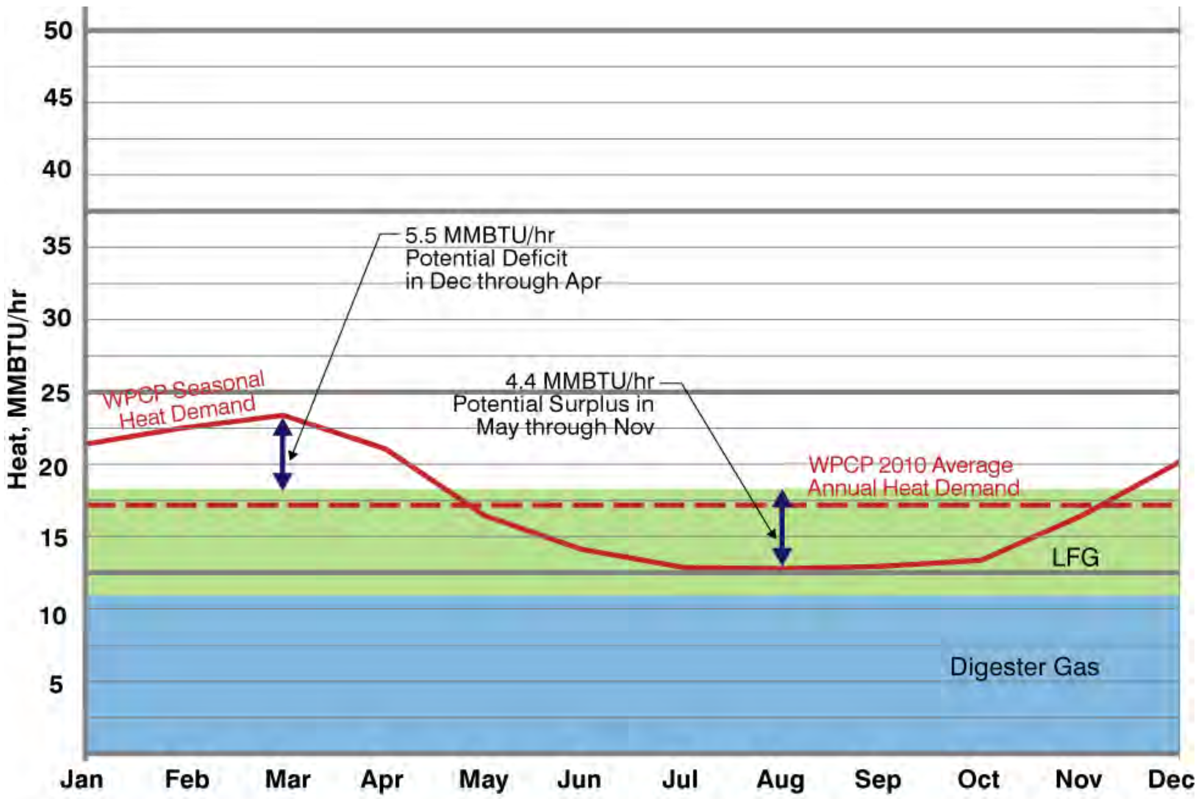

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Figure 9
SEASONAL HEAT DEMAND
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

4.0 AVAILABLE OPPORTUNITIES

4.1 Energy Management

Two important aspects of energy management at the WPCP are the efficiency of the energy consuming processes and equipment and the plant's ability to temporarily reduce its power load to respond to the electric utility's critical peak demand periods. A summary of some common energy management strategies is provided in Appendix B

4.2 Self-Generation

There are also a variety of opportunities available for the WPCP to generate heat and power onsite using available resources including biogas, solar PV, wind, and algae. The City must evaluate each of these opportunities from a holistic perspective in lieu of solely on their technical merit. This is critical to ensure that implementation of a particular technology will not adversely impact the City's ability to meet other goals such as meeting discharge requirements or maintaining stable conditions in treatment processes. Although technologies are constantly evolving and more opportunities are likely to be available in the future, Appendix C provides a comprehensive list of some of the technologies that are commercially available at this time.

4.3 Funding Sources

In addition to identifying energy management strategies and self-generation opportunities, the City will also need to investigate funding sources to determine the best way to finance energy projects. Qualifying energy projects fall into four major categories:

- City financed, owned, and operated
- Public-Private partnerships (PPP)
- Private sector financed, owned, and operated on City property
- Pilot projects to test innovative, pre-commercial technologies

Detailed descriptions of each of these major categories as well as a list of the currently available grant and subsidized loan programs to help fund energy efficiency and renewable energy projects can be found in Appendix E.

5.0 FOCUS INWARD (WPCP PROCESS AREA)

As presented earlier, the overall energy management approach will initially have an "inward focus" by targeting the WPCP internal goals of being green, achieving self-sufficiency, and optimizing cost. Figure 10 shows the site process area included in this inward focus, which includes the proposed area for future biosolids processing presented in PM 5.2.

As indicated in previous sections, the WPCP can achieve these goals with various technologies (e.g. cogeneration, solar, wind, engine-driven blowers, high strength organic waste, two-phase digestion, algae, and heat generation). While many of the technologies identified in Appendix C may not be appropriate for the WPCP at this time, implementation of cogeneration, and solar power technologies could present an immediate benefit at minimal cost based on current incentives and funding opportunities. As a result, these technologies along with heat pump technology were evaluated further to determine which provided the greatest overall energy benefits to the WPCP. A summary of the alternative analysis is provided in Appendix D. While currently not feasible, wind technologies should be evaluated in the future.

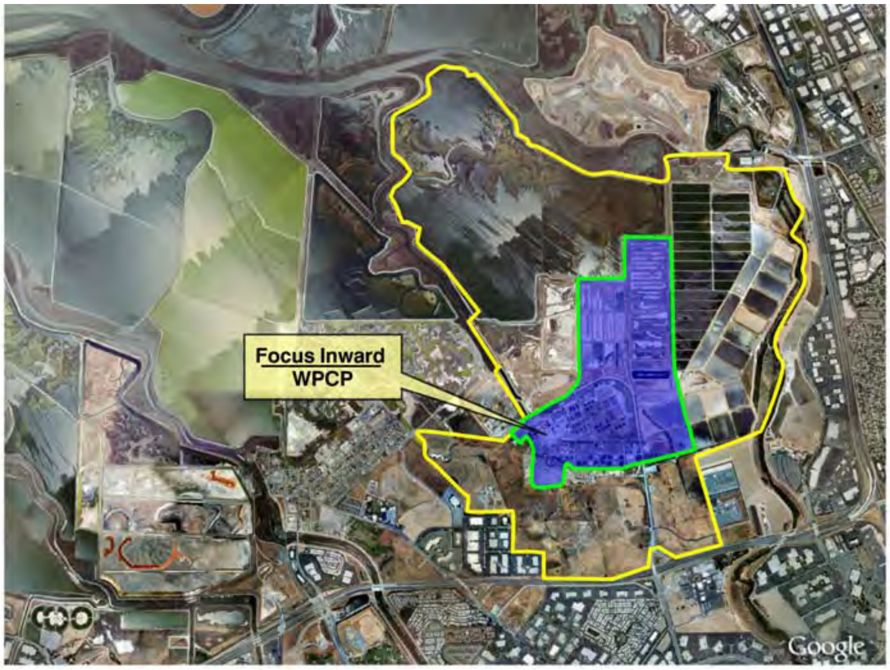

Figure 10
INWARD FOCUS AREA
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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5.1 Findings

5.1.1 <u>Cogeneration Alternative Analysis</u>

Table 10 shows the results of the cogeneration alternative economic analysis based on two utility pricing escalation scenarios. While this analysis indicates that fuel cells are significantly more costly than other alternatives, the CPUC is considering improving the Self-Generation Incentive Program (SGIP) funding availability for fuel cells which could improve the Alternative 3 economics.

As shown in Table 10, it is not cost effective to replace the existing engine-generators with new technologies at this time for two reasons: (1) they have remaining useful life and (2) the higher efficiencies associated with other technologies do not provide significant economic benefit to pay for the higher capital costs. Triggers for replacement of the existing engines include changes in emission regulations discussed in Section 2.6, excessive maintenance requirements, catastrophic engine failures, or a need to expand onsite generation capacity to accommodate increased digester gas production. These triggers fall under the Capital Improvement Program (CIP) trigger categories of regulatory requirement, improved performance, condition, and increased flows/loads respectively.

Table 10	Cogeneration Project Economic Summary San José/Santa Clara Water Pollution Control Plant Master Plan City of San José	
Alternative	**Present Worth of Total Energy Cost (1.7% Escalation)**	**Present Worth of Total Energy Cost (4% Escalation)**
Alternative 0 (Base Case)	$205,550,000	$300,490,000
Alternative 1 (Add New Engines)	$228,140,000	$329,400,000
Alternative 2 (Add New Turbines)	$227,570,000	$328,310,000
Alternative 3 (Add New Fuel Cells)	$262,360,000	$365,330,000

It is anticipated that emission regulation changes could be adopted as soon as 2015, and it is likely that the City would have 3 to 4 years to achieve compliance. It is also anticipated that additional digester gas generated from anaerobic digestion process improvements, FOG addition, coupled with MSW may provide the WPCP with more gas than can be used in their existing cogeneration systems. As a result, the WPCP has elected to include addition of a new 4.6 MW gas turbine in the current 5-year CIP (2010/11 – 2014/15) and will prepare to install additional 4.6 MW gas turbines after 2015 as needed to address aging infrastructure, changes to emission regulations, and increased digester gas production. The projections for increased digester gas due to FOG, and scum and grease addition are based on the estimates provided by Brown and Caldwell (BC) in TM 3.3 – Design Criteria for Digester Modifications and Gas System Improvements. (See Appendix F for projected loading and associated gas production).

All DG cogeneration technologies required high level gas treatment systems to protect the equipment. The capital and O&M costs for this have been captured in each of the cogeneration alternatives and are reflected in the present worth values provided in Table 10. Typically, gas treatment system O&M is provided through the gas treatment system supplier through a separate service contract. This service contract often includes monthly testing and reporting, periodic media replacement, and annual calibration of instruments. It is recommended that the WPCP evaluate which O&M services would be best performed by plant staff and which should be contracted out as part of the preliminary design effort for projects that will install new cogeneration systems or upgrade existing systems to meet air regulations.

5.1.2 Solar Alternative Analysis

Based on recent feasibility studies for other plants, direct purchase is favorable based on pure economics. However, cash flow is an issue that must also be considered when evaluating future economic conditions and the cost of financing. Under the direct purchase scenarios evaluated in Appendix D, the cost per kWh would be more expensive than what the City is currently paying.

If the City is able to work out an agreement with a third party to take advantage of the 30 percent Investment Tax credit (ITC), the average energy cost for a 1 MW solar PV facility could be equal or less to what the City is currently paying for electric power. Therefore, the City should proceed with the planned 1 MW solar PV PPA as planned and conduct an evaluation for additional solar PV systems in the future as part of a detailed energy strategic plan. Since solar generation technologies can only provide power when the sun is shining, the City should evaluate advanced energy storage (AES) and high-pressure DG as part of a detailed energy strategic plan. CIP triggers include economic benefit and policy decision.

5.1.3 Wind Alternative Analysis

Similar to solar PV, direct purchase is favorable based on pure economics for wind projects. However, once again cash flow is an important factor that should be considered. The WPCP's available wind resource is lower than the wind speed that is considered ideal, so the economic benefit for a direct purchase approach would be limited.

However, wind energy developed in a public-private partnership (PPP) mode could still be a feasible part of the City's energy management strategy. Careful evaluation of the wind turbines effect on the bird population at the WPCP must be conducted before a firm decision to implement wind energy is made. In addition, further consideration is warranted should future advancements in wind turbine technology allow for power generation at lower cut-in speeds. CIP triggers once again include economic benefit and policy decision. Therefore, wind turbines should not be installed at this time, but evaluated further in the future.

5.2 Future Energy Supply Revisited

Implementation of the improvements recommended in PM 5.1 and PM 5.2 will help the WPCP meet future reliability and self-sufficiency criteria. However, additional strategies will still be necessary to meet all of the energy management goals. As a result, the prior future energy supply analyses have been revisited to identify the projected shortfalls after implementing some of the most likely improvements.

5.2.1 Reliability Analysis

As previously noted, the WPCP must have adequate infrastructure in place to satisfy the critical electrical demand. Section 3.4.1 of this PM demonstrated that the existing onsite infrastructure is adequate to meet the minimum electrical and aeration air reliability criteria for 2010, however additional infrastructure would be required to meet the reliability criteria in the future.

As previously noted in Table 4, the minimum electrical demand meeting reliability criteria for 2040 is 8.2 MW. Based on the CIP, the WPCP will have completed the digester improvements, added a FOG receiving station, installed a 1.4 MW fuel cell facility, and installed a new 4.6 MW gas turbine in the immediate term. In addition, it is likely that the

WPCP will have installed additional gas turbines (one duty and one standby) during the near-term and long-term phases to replace aging infrastructure and meet air emission regulations. Based on implementation of these improvements, the reliable onsite electric power generation capacity assuming one largest unit out of service is as follows:

• One 1,400 kW fuel cell	= 1,400 kW
• Two 4,600 kW gas turbines	= 9,200 kW
Total	**= 10,600 kW**

Thus, the planned onsite generation infrastructure will be adequate to meet the minimum electrical reliability criteria for year 2040. This assessment is based on the installation of the infrastructure noted above. However, a final selection of type, size, and number of units will be made during the design phase, at which point this assessment would need to be modified accordingly. It should be noted for complete reliability, there should be standby engine generators with capacity equivalent to the fuel cell and new gas turbine.

5.2.2 Power

Implementation of these improvements will also enable the WPCP to meet its future reliability criteria using green sources and will bring the WPCP closer to meeting the self-sufficiency goal for meeting its overall power demands. Table 11 provides a summary of the incremental contribution of each component for the critical power balance, while Figure 11 shows how implementation of these improvements will enable the WPCP to meet the reliability criteria through green sources. Similarly, Table 12 shows the incremental contribution of each component for the overall power balance, while Figure 12 shows how the improvements will bring the WPCP closer to meeting its self-sufficiency goal.

5.2.3 Heat

Once the aforementioned improvements are implemented, the WPCP will have an even greater surplus of heat available. Table 13 provides a summary of the incremental contribution of each of these improvements. As previously noted, one potential use for this surplus heat would be in a heat drying process for dewatered cake solids, as indicated in Figure 13 (example shown of the heat demand for 20 percent of the dewatered cake solids taken to a heat dryer). Appendix G shows the analysis for the heat drying requirements. This analysis indicates that drying 20 percent of the dewatered solids is a conservative estimate once the estimated FOG, scum and grease are realized. As a result, it may be possible to dry more than 20 percent solids at certain times of the year. However, due to the seasonal heat demand (also shown in Appendix G), natural gas would be needed to supplement heat drying requirements if more than 20 percent heat drying is required. Another potential use would be to utilize the excess heat in an organic rankine cycle process to generate electricity.

Table 11	Critical Power Balance Revisited San José/Santa Clara Water Pollution Control Plant Master Plan City of San José		
Item		**Incremental Contribution (MW)**	
		2010	**2040**
Supply	DG Baseline	3.2	4.4
	LFG Baseline	2.3	1.2 (1)
	Digester Improvements	0.0	0.9
	Fuel Cell (2)	0.0	0.5
	Gas Turbines (2)	0.0	1.7
	FOG/Scum and Grease	0.0	3.3
Supply Subtotal		**5.5**	**12.0**
Demand Subtotal (From Table 4)		**(6.6)**	**(8.2)**
Net Total		**(1.1)**	**3.8**

Notes:
(1) Assumes LFG will be available in reduced quantities after closure of Newby Island landfill in 2025.
(2) Represents additional contribution through increase in efficiency over existing cogeneration equipment.

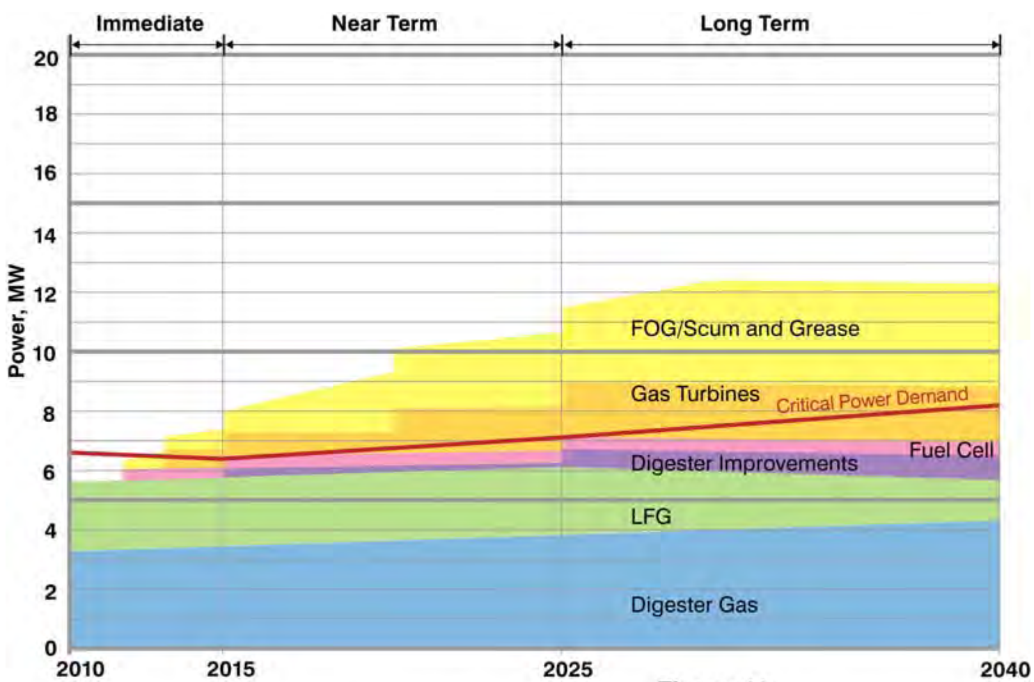

Figure 11
MEETING CRITICAL POWER DEMAND THROUGH ONSITE GENERATION REVISITED
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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Table 12	Overall Power Balance Revisited San José/Santa Clara Water Pollution Control Plant Master Plan City of San José				
		Incremental Contribution (MW)			
Item		**2010**	**2015**	**2025**	**2040**
Supply	DG Baseline	3.2	3.4	3.8	4.4
	LFG Baseline	2.3	2.3	2.3	1.2 (1)
	Digester Improvements	0.0	0.3	0.6	0.9
	Fuel Cell (2)	0.0	0.5	0.5	0.5
	Gas Turbines (2)	0.0	0.8	1.7	1.7
	FOG/Scum and Grease(3)	0.0	0.7	2.5	3.3
Supply Subtotal		**5.5**	**8.0**	**11.4**	**12.0**
Demand Subtotal (From Table 5)		**(10.7)**	**(11.3)**	**(15.0)**	**(17.9)**
Net Total		**(5.2)**	**(3.3)**	**(3.6)**	**(5.9)**

Notes:

(1) Assumes LFG will be available in reduced quantities after closure of Newby Island landfill in 2025.

(2) Represents additional contribution through increase in efficiency over existing cogeneration equipment.

(3) Based on estimates of quantities of FOG and Scum and Grease by Brown and Caldwell.

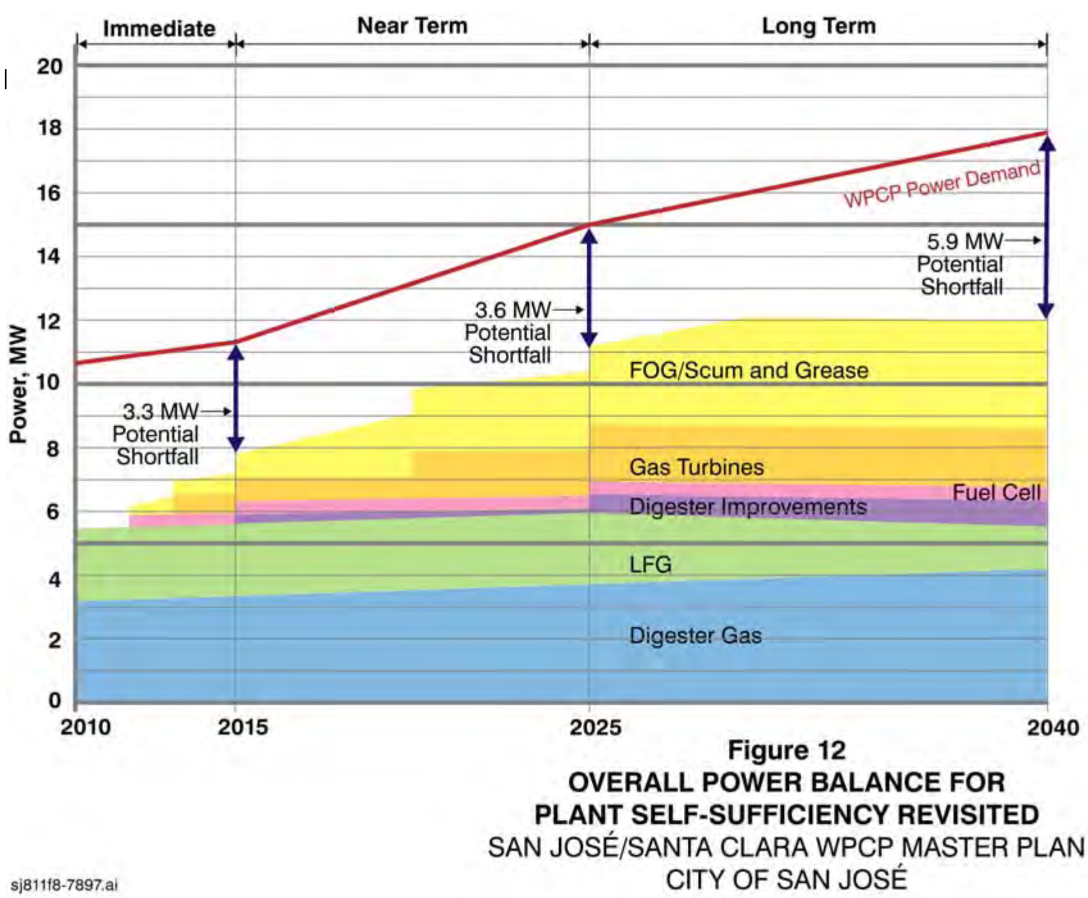

Figure 12
OVERALL POWER BALANCE FOR PLANT SELF-SUFFICIENCY REVISITED
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

Table 13 Overall Heat Balance Revisited
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

	Item	**Incremental Contribution (MMBTU/hr)**			
		2010	**2015**	**2025**	**2040**
Supply	DG Baseline	10.3	10.8	11.6	12.7
	LFG Baseline	7.4	7.4	7.4	3.7 (1)
	Digester Improvements	0.0	0.9	1.8	2.6
	Fuel Cell (2)	0.0	0.1	0.1	0.1
	Gas Turbines (2)	0.0	3.3	6.7	6.7
	FOG/Scum and Grease(3)	0.0	2.3	7.9	10.8
Supply Subtotal		**17.7**	**24.8**	**35.5**	**36.6**
Demand Subtotal (From Table 6)		**(17.4)**	**(16.5)**	**(17.0)**	**(19.2)**
Net Total		**0.3**	**8.3**	**18.5**	**17.4**

Notes:
(1) Assumes LFG will be available in reduced quantities after closure of Newby Island landfill in 2025.
(2) Represents additional contribution through increase in efficiency over existing cogeneration equipment.
(3) Based on estimates of quantities of FOG and Scum and Grease by Brown and Caldwell. Assumes 30% of heat can be recovered from gas generated from FOG/Scum and Grease based on more efficient cogeneration equipment.

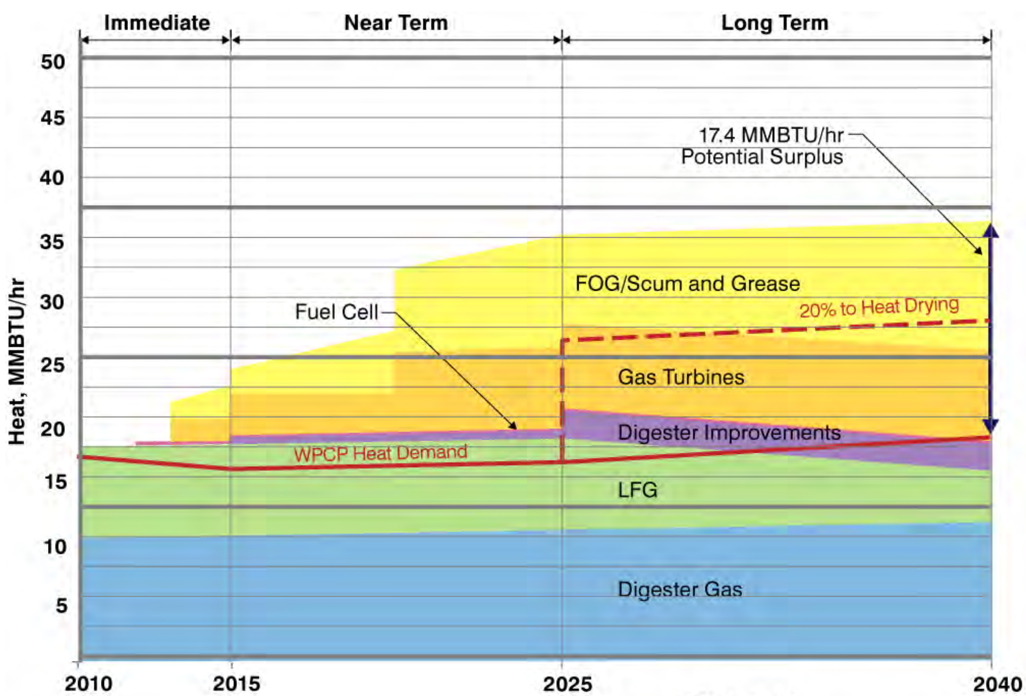

Figure 13
OVERALL HEAT BALANCE FOR PLANT SELF-SUFFICIENCY REVISITED
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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6.0 FOCUS OUTWARD (AREA SURROUNDING THE WPCP)

After the WPCP is able to achieve the internal goals, the next focus for the energy management plant will be to evaluate the potential for meeting self-sufficiency for the City property outside of the area developed for process facilities. Figure 14 shows the area of the site included in this outward focus.

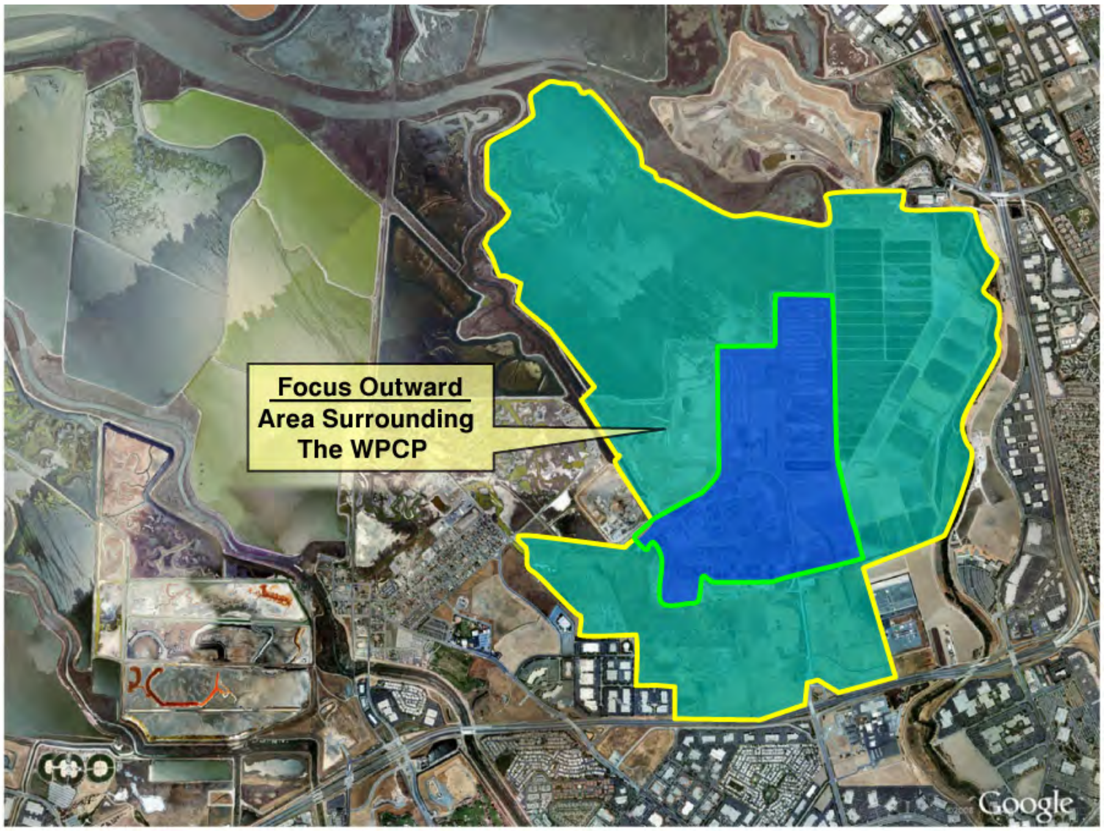

Figure 14
OUTWARD FOCUS AREA
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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As indicated in the land use alternatives, approximately 60 acres have been reserved in the form of a renewable energy field for renewable energy project development. Up to 1 MW could be exported from this site and used at other City locations requiring power. The Local Government Renewable Energy Self Generation Program (AB 2466) became effective on January 1, 2009. This law allows a local government (or a third party on behalf of the local government) to install renewable generation of up to 1 MW at one location within its geographic boundary and generate credits that can be used to offset charges at one or more other locations within the same geographic boundary. PG&E would meter the electricity the generator exports to the utility grid (beyond whatever on-site needs it may have), and calculate the credits. The local government would identify one or more “accounts” that will receive the credits. The benefiting accounts must be within the local government’s geographic boundaries, and on property that it owns, operates, or controls.

The energy generation system must be renewable in accordance with the definition provided in the California RPS (i.e. certified by the CEC as a renewable generator) and must be no larger than 1 MW in size. The legislature determined that the Local Government Remote Renewable Energy Program would only be available until 250 MW of remote renewable generation has interconnected statewide. It is unclear at this time whether a local government participating in the 2466 program can also receive a California Solar Initiative (CSI) or SGIP rebate. CPUC will likely resolve this issue in the approval of utility tariffs implementing AB 2466.

Assuming land use development becomes a reality by 2025, the outward focus could include potentially providing power and heat to the various developed areas that could be constructed over the planning period. Figures 15 and 16 illustrate the anticipated power and heat demands for this development.

These figures show that the potential demand for power and heat could be substantial and therefore presents the opportunity to create a local market. Similar to what was evaluated for the WPCP, the site can address these demands through various approaches.

6.1 Solar PV

It is anticipated that the commercial development will also have land available for installing solar PV facilities on the roofs of the buildings and perhaps as part of the renewable energy field. Every five acres of land allocated to solar development could provide approximately 1 MW of solar power. As previously indicated in Appendix D, the cost per kWh for projects larger than 1 MW is more expensive than what the City is currently paying. However further investigation is warranted as the power rates for the commercial development will be different than for the WPCP and utility supplied rates have been increasing while the cost of installing solar power has been decreasing. CIP triggers include economic benefit and policy decision.

6.2 Municipal Solid Waste (MSW)

The City is already in discussion with several vendors about implementing various technologies to generate heat and power from the organic portion of the municipal solid waste (MSW) stream. The City has received significant interest from vendors, including a proposal for a dry fermentation anaerobic digestion facility located at the Nine Par site from Zero Waste Energy Development Company (Zero Waste).

Zero Waste is a partnership between Green Waste Recovery and Zanker Road Resource Management. Under the initial proposal, Zero Waste planned to develop 40 acres of the former Nine Par Landfill site and construct a dry fermentation anaerobic digestion facility located on the North side of Los Esteros Road adjacent to the Zanker Road Landfill and

Figure 15
WPCP AND DEVELOPMENT NEEDS-POWER DEMAND
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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Figure 16
WPCP AND COMMERCIAL DEVELOPMENT HEAT DEMAND
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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Zanker Materials Recovery Facility. The new facility would use a proprietary process owned by Bekon Energy Technologies where the end products of the process are biogas and compost. The facility would be developed in phases, with the first phase designed for a capacity of 50,000 tons of organic waste per year. To make beneficial use of the biogas generated, Zero Waste would also install a combined heat and power plant capable of producing 1.73 MW of electric power and 6.39 MMBTU/hr of heat.

Recent information has indicated that the first phase could be operational as soon as 2012, and the processing capacity could be as much as 90,000 tons of organic waste per year. As a result, it is estimated that up to 3.1 MW of electric power and 11.5 MMBTU/hr of heat could be produced if a larger combined heat and power plant is constructed.

Because of the potential synergies with the WPCP, the City should continue to pursue this and other MSW facility proposals in the immediate-term as part of a detailed energy strategic plan. CIP triggers once again include economic benefit and policy decision.

7.0 IMPLEMENTATION STRATEGIES/RECOMMENDATIONS

Energy improvements will be implemented at different times throughout the planning period. The anticipated schedule for implementing these improvements has been grouped into three major categories (immediate, near-term, and long-term). Figure 17 summarizes the recommended energy improvements that should be implemented during each of these groupings.

Time Period	Increase Efficiency	Increase Digester Gas Production	New Green Technology	Outside Renewable Energy
<2015	• Automation • Process Optimization • Fine bubble • VFDs • High efficiency pumps/HVAC/ lighting • CEPT(1)	• CEPT(1) • Digester upgrades	• Fuel cell • High-efficiency cogen • Solar • Algae pilot plant • Greenhouse drying(1)	• FOG • MSW(1) • Food(1)
<2025	• Upstream intervention(1) • Co-thickening	• Digester upgrades • Covered lagoons	• High-efficiency cogen or fuel cells • Wind(1) • Solar	• FOG • MSW(1) • Food(1) • Calpine(1)
<2040			• Thermal processing(1) • Algae farming(1)	• FOG • MSW(1) • Food(1)

Notes:
(1) Less feasible alternative due to unknowns (more evaluation necessary)

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Figure 17
ANTICIPATED ENERGY IMPLEMENTATION SCHEDULE
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

Actual phasing of these recommended improvements will be based on a variety of considerations. These considerations will act as triggers that may accelerate the anticipated implementation schedule identified in Figure 17. Table 14 summarizes some of these key considerations and their respective impact on the strategic plan.

Table 14 Energy Alternatives Summary
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Future Considerations and Trends	Impact on Strategic Plan
Confirmation of all outside energy sources	Develop a detailed energy strategic plan
Aging cogeneration equipment	Replace with new high-efficiency cogeneration equipment
AQMD regulatory changes (by 2020)	Replace existing cogeneration equipment with lower emission technologies or retrofit with selective catalytic reduction system
DG and LFG generation inadequate to meet average power demand	Pending the outcome of the FOG pilot, proceed with construction of a permanent full scale FOG facility
Gas generation exceeds current demand	Construct high-pressure gas storage facility and install additional cogeneration equipment as required
Heat recovery exceeds current demand	Explore opportunities to export power and heat to surrounding development
LFG costs increase	Explore opportunities for purchased DG or power from MSW, expand FOG and food waste program
LFG availability decreases	Explore opportunities for purchased DG or power from MSW, expand FOG and food waste program
Power costs increase	Explore solar PV opportunities and look for other outside sources of power such as MSW
Chemical costs decrease	Pending the outcome of the CEPT pilot, proceed with construction of a permanent CEPT feed station
Enhanced SGIP or other grant opportunities	Monitor opportunities, apply where appropriate, review technology selections
Changes to tax benefit availability to the private sector	Revisit technology selections and organizational arrangement (PPA vs. City ownership)

7.1 Immediate

Immediate efforts (<2015) should be directed toward meeting the WPCP inward focusing energy management goals. Since cogeneration Alternatives 1 through 3 (add new engines, add new turbines, or add new fuel cells), are not economically viable at this time, it is recommended that the WPCP continue to operate and maintain their existing Building 40 cogeneration engines and engine-driven blowers to make beneficial use of the available DG and LFG for the next few years. However, in the meantime the City should:

- Complete the process optimization, automation, and efficiency improvement efforts that have already been started
- Conduct an annual energy audit to identify additional, cost-effective opportunities and implement recommended measures
- Proceed with the planned 1 MW solar PV PPA
- Proceed with the planned 1.4-MW fuel cell PPA
- Upgrade the existing engines fuel system to operate without supplemental NG
- Implement a FOG pilot plant (per PM 5.2)
- Develop a policy to secure FOG and food waste feedstocks to boost DG production
- Proceed with the proposed digester upgrades recommended in PM 5.2
- Monitor the current CPUC process for modifying the SGIP and participate in encouraging changes which would benefit the City (larger MW limits, higher SGIP payments, etc)
- Unless there are changes to the SGIP that would favor fuel cells or other advanced technologies, install a 4.6-MW gas turbine after 2012 to address aging infrastructure and pending regulatory changes, and provide additional cogeneration capacity to account for anticipated increased gas availability through digester improvements, FOG, and MSW. These infrastructure upgrades will also address reliability considerations identified in Section 3.4.1.
- Evaluate the feasibility of installing a high-pressure DG storage facility to handle increased DG generation from new feedstocks (and possible MSW facility) and address diurnal variability. Determine whether this could be SGIP grant eligible as an AES System.
- Develop concepts for an algae energy pilot project and monitor grant funding opportunities
- Develop a detailed energy strategic plan
  - Explore opportunities with the proposed MSW facility
  - Conduct further analysis of potential opportunities to optimize use of available heat

- Conduct further analysis of solar PV to determine sizing and siting required to address WPCP long-term total power demand shortfall
- Conduct further analysis of high-efficiency cogeneration alternatives and prepare to install additional 4.6-MW gas turbines (minimum of one duty and one standby) to address aging infrastructure and regulatory changes
- Conduct further analysis of large scale solar PV to determine sizing and siting required to address commercial development power demand
- Conduct further analysis of AES systems and identify funding options and incentive programs to offset the high capital cost
- Conduct further analysis of thermal processing
- Explore opportunities with Calpine
- Explore opportunities to participate in demand response programs
- Explore community-scale energy systems for land use so that development can be "net zero" in energy consumption.

- Monitor power and chemical costs and re-evaluate CEPT should the trends begin to change. Prepare to construct a permanent CEPT feed station pending the outcome of the current full-scale pilot work

7.2 Near-Term

Near-term efforts (<2025) should expand on the immediate efforts directed toward meeting the WPCP inward focusing energy management goals and should also begin to consider outward focusing energy management goals in anticipation of commercial development. During this phase the City should:

- Complete the proposed digester upgrades recommended in PM 5.2
- Begin co-thickening of sludge as recommended in PM 5.2
- Expand FOG facilities based on pilot results
- Pending results from the immediate team investigations begin integration with MSW facilities
- Implement project to relocate and cover the sludge lagoons to capture additional DG as recommended in PM 5.2.
- Monitor wind turbine advancements and conduct further analysis of wind PPA to determine economic feasibility should newer wind turbine technology allow for power generation at lower cut-in speeds

7.3 Long-Term

Long-term efforts (<2040) should expand on the near-term efforts and be directed more towards the outward focusing energy management goals. During this phase the City should:

- Expand FOG and food waste program
- Expand MSW facility integration
- Prepare to construct a permanent algae growing/harvesting facility pending the outcome of the pilot work

8.0 GREENHOUSE GAS EMISSIONS

The previous sections have documented the phased implementation of improvements starting with the existing facilities in 2010 through build-out in 2040. The purpose of this section is to provide the methodology for estimating greenhouse gas (GHG) emissions estimates resulting from treatment plant operations for years 2010 and 2040. These estimates will provide a gross evaluation of the City's ability to reduce GHGs over the proposed 30-year planning period.

8.1 Methodology

The development of GHG emissions estimates requires a set of boundary conditions to define the life cycle stages, the unit processes, and the time frame that is included in the analysis. For this inventory, the annual needs for the operations phase are considered for years 2010 and 2040, which include:

- Operation energy (electricity and fuel) consumed by the unit processes,
- Onsite general stationary combustion units,
- Nitrification and denitrification processes,
- Discharged effluent,
- Production and transport of chemicals consumed for the proper treatment of wastewater (i.e., sodium hypochlorite, sodium bisulfite, and polymer), and
- Biosolids treatment, transport, and end use/disposal options.

8.1.1 Estimating GHG Emissions in Terms of CO_2 Equivalents

The data for each of the parameters were collected for the year 2010 and estimated for the year 2040. Appropriate emission factors were selected and the data were input into Carollo's GHG emissions inventory model to estimate annual quantities of fossil fuel-based (anthropogenic) and non-fossil fuel-based (biogenic) GHG emissions. For this analysis, biogenic emissions refer only to carbon dioxide (CO_2) emissions from the combustion of biogas. The GHGs included in this estimate are CO_2, methane (CH_4), and nitrous oxide (N_2O) generated using the following basic methods.

- *Electricity Consumption (kilowatt-hours) x Emission Factor*
- *Gas Consumption (standard cubic feet) x Emission Factor*
- *Service Population x Emissions Factor (N_2O from nitrification/denitrification process)*
- *Total Effluent Nitrogen Load (kilograms) x Emission Factor (N_2O from discharged effluent)*
- *Chemical Produced (unit weight) x Specific Energy (unit energy per unit weight of chemical) x Emission Factor*
- *Vehicle Fuel Consumption (gallons and miles traveled) x Emission Factor*
- *Biological Oxygen Demand (pounds) x Emission Factor (CH_4 from lagoons)*
- *Annual Dry Solids Composted (kilograms) x Emission Factor (CH_4 from composting)*

Emissions were converted into carbon dioxide equivalent (CO_2e) emissions. The major GHG in the atmosphere is CO_2. Other GHGs differ in their ability to absorb heat in the atmosphere. For example, CH_4 has 21 times the capacity to absorb heat relative to CO_2 over a hundred-year time horizon, so it is considered to have a global warming potential (GWP) of 21. Therefore, a pound of emissions of CO_2 is not the same in terms of climatic impact as a pound of CH_4 emitted. Carbon dioxide equivalent emissions are calculated by multiplying the amount of emissions of a particular GHG by its GWP (see Table 15).

Table 15 Greenhouse Gases and Their Associated Global Warming Potentials (GWPs)
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Greenhouse Gas	GWP* (unit mass CO_2e/unit mass of GHG emitted)
Carbon Dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous Oxide (N_2O)	310

* GWPs from the Intergovernmental Panel on Climate Change Second Assessment Report (1996) for a 100-year time horizon. These GWPs are still used today by international convention and the U.S. to maintain the value of the carbon dioxide “currency,” and are used in this inventory to maintain consistency with international practice.

8.2 Assumptions

For planning purposes, and/or if the data are unavailable, estimating GHG emissions requires simplifying assumptions. The following assumptions were used to complete the estimates presented in this report.

2010 GHG emissions estimates assumptions included:

- Average daily annual flow is estimated to be 125 million gallons per day based on information from PM 3.8.
- Electricity and fuel (i.e., diesel, biogas, and natural gas) consumption are based on metered information.
- Chemical consumption:
  - The only chemicals consumed in 2010 are sodium hypochlorite and sodium bisulfite for disinfection.
  - Sodium hypochlorite is manufactured in and supplied from a company in Tracy, California.
  - Sodium bisulfite is manufactured in and supplied from a company in Redwood City, California.
- Annual load of biological oxygen demand into the lagoons was estimated to be 33,000 pounds per day based on information from PM 3.3 of the Digestion Project.
- Total annual nitrogen effluent load in kilograms was estimated using an effluent concentration of 15 milligrams per liter based on information from PM 3.8.
- Biosolids are dewatered onsite in anaerobic and facultative lagoons and drying beds to 80% solids (based on information from PM 3.3 of the Digestion Project), mixed with soil, and are driven a distance of 1 mile to the nearby Newby Island Landfill. Methane is assumed to be generated in the lagoons and is included in this analysis.
  - The landfill receiving the biosolids is assumed to have a comprehensive landfill gas collection system (LGCS) per EPA's New Source Performance Standards. A comprehensive LGCS is assumed to be 75% efficient (i.e., 25% of the gas escapes as fugitive emissions which are included in the analysis).
- For this analysis all transport is assumed to be provided by a 1998 heavy duty truck averaging 7 miles per gallon of California diesel fuel.

2040 GHG emissions estimates assumptions included:

- Average daily annual flow is estimated to be 172 million gallons per day based on information from PM 3.8.

- Electricity consumption in 2040 is based on estimates presented in section 3 above.

- Fuel (i.e., diesel, biogas, and natural gas) consumption significantly changes due to replacing the cogeneration system engines with turbines.
  - Diesel was previously used to fuel the engine pilot lights, but is no longer needed for turbines.
  - Though landfill gas availability will decrease by half by 2040, biogas production/consumption will increase overall due to the projected increase in influent sewage sludge and the addition of fats, oils, and grease.
  - Natural gas consumption decreases due to increased biogas production and the replacement of engines with turbines, leaving only a fraction to be purchased for boilers and other uses.

- Chemical consumption:
  - The chemicals consumed in 2040 are sodium hypochlorite and sodium bisulfite for disinfection and polymer for dewatering and thickening.
  - Sodium hypochlorite is manufactured in and supplied from a company in Tracy, California.
  - Sodium bisulfite is manufactured in and supplied from a company in Redwood City, California.
  - Polymer is assumed to be manufactured in and supplied from a company in Los Angeles, California.

- While the lagoons are covered, there is uncertainty regarding the volatile solids destruction. Furthermore, there exists the possibility of bypassing the lagoons entirely. Therefore, no destruction in the lagoons is assumed. Mechanical dewatering takes place before the biosolids are split into four different treatment and end use/disposal tracks:
  - 10% - Onsite greenhouses, 65% solids are driven 10 miles to the land application site. It is assumed that land application of biosolids is an aerobic process where the DOC in the waste material is converted into CO_2 and is not included in this analysis.
  - 35% - Offsite composting, 25% solids are driven 120 miles to an offsite composting facility.
    - Composting is an aerobic process with a large fraction of the degradable organic carbon (DOC) material converted into CO_2, which is not included in the analysis. However, some N_2O is produced during composting, and CH_4 is formed in anaerobic sections of the compost. Estimates of CH_4 and N_2O are included in the analysis.
  - 20% - Onsite thermal drying, 70% solids are driven 10 miles to application site. It is assumed that land application of biosolids is an aerobic process where the

DOC in the waste material is converted into CO_2 and is not included in this analysis.

- 35% - Dewatered 25% solids are driven an average distance of 120 miles to a landfill or land application site.
  - * The landfills receiving the biosolids are assumed to have a comprehensive LGCS per EPA's New Source Performance Standards. A comprehensive LGCS is assumed to be 75% efficient (i.e., 25% of the gas escapes as fugitive emissions which are included in the analysis).
  - * It is assumed that land application of biosolids is an aerobic process where the DOC in the waste material is converted into CO2 and is not included in this analysis. In addition, the offset of fertilizer use (and of GHG emissions associated with its production) due to the application of biosolids is not included in this analysis.

- Total annual nitrogen effluent load in kilograms was estimated using an effluent concentration of 8 milligrams per liter based on information from PM 3.8.

- For this analysis all transport is assumed to be provided by a 1998 heavy duty truck averaging 7 miles per gallon of California diesel fuel.

8.3 Summary of GHG Emissions Estimates

The resulting GHG emissions estimated for treatment plant operations for 2010 and 2040 are summarized in Table 16 and Figure 18. Table 16 shows the emissions in: 1) total annual metric tons of CO_2e and 2) metric tons of CO_2e per million gallons of treated wastewater. While the total annual emissions for 2010 and 2040 are nearly the same, normalizing the emissions over the annual flows shows that 2040 emissions are 30 percent lower than 2010 emissions per million gallons of treated wastewater.

Table 16 Summary of Greenhouse Gas Emissions Estimates for 2010 and 2040
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

	Metric Tons CO_2e Emissions per Year	Metric Tons CO_2e Emissions per MG
2010	118,705	2.60
2040	114,878	1.82
Percent Decrease	3.2%	29.7%

Notes:
(1) CO_2e: carbon dioxide equivalent
(2) MG: million gallons

Figure 18 shows the primary sources of GHG emissions for 2010 are mainly purchased electricity, natural gas combustion, biogas combustion (primarily biogenic CO_2, which is shown since it is included in GHG reporting to the state), and uncovered lagoons. For 2040, the primary sources of GHG emissions are the same as that for 2010 with the exception of the uncovered lagoons (since they will no longer exist). If the biogenic emissions (CO_2 resulting from biogas combustion) are not included, the 2040 emissions are approximately 50 percent lower than 2010 emissions per million gallons of treated wastewater.

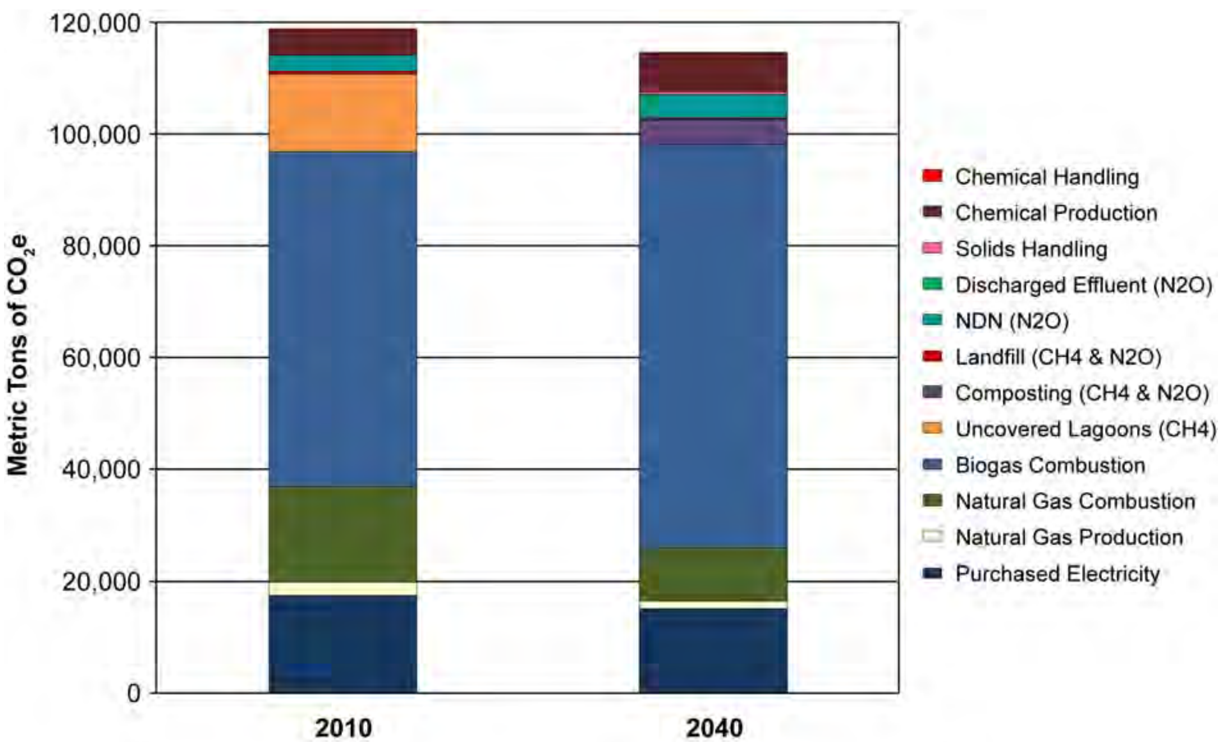

Figure 18
ANNUAL TOTAL METRIC TONS OF CARBON DIOXIDE EQUIVALENT EMISSIONS
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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APPENDIX A – THEORETICAL MINIMUM POWER DEMAND

APPENDIX A – THEORETICAL MINIMUM POWER DEMAND

The theoretical minimum power demand for the WPCP assumed “ideal process operating conditions” including upgrade of all the aeration basin diffusers by 2010, belt press dewatering, CEPT, and the following assumed power demand efficiencies:

- 85 percent efficient pumping
- 80 percent efficient aeration blowers with 95 percent efficient motors

Although these ideal conditions are not mutually exclusive and all would not be implemented, this analysis shows that the WPCP’s ongoing improvements and those recommended in PMs 5.1 and 5.2 already get the WPCP close to the minimum power demand. Table A1 provides a summary of this analysis.

Table A1 Theoretical Minimum Electrical Demand
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

		Demand (MW)			
Item		**2010**	**2015**	**2025**	**2040**
Onsite Demand	Headworks	0.3	0.3	0.4	0.4
	Primary Treatment	0.1	0.1	0.1	0.1
	Secondary Treatment	1.1	1.1	1.2	1.4
	Aeration air	3.7	3.4	4.4	5.1
	Filters	0.6	0.6	0.6	0.7
	Disinfection	0.02	0.02	0.02	0.02
	Reuse Pump Station	0.8	0.8	1.1	1.3
	Solids Handling	1.2	1.2	1.5	1.7
	Miscellaneous (10%)	0.8	0.8	0.9	1.1
Total		**8.5**	**8.3**	**10.2**	**11.9**

APPENDIX B – ENERGY MANAGEMENT STRATEGIES

APPENDIX B – ENERGY MANAGEMENT STRATEGIES

Energy Efficiency

Since it is usually less expensive to reduce energy consumption through cost effective energy savings measures than to install renewable energy generation systems, the City should confirm that the most efficient equipment and systems are being used at the WPCP. This is typically determined by conducting an energy audit. The audit quantifies the energy consumption of each device and then performs cost benefit analyses for the replacement of less efficient system and equipment with state of the art equipment. The following systems are typically considered in a wastewater treatment plant energy audit:

- Aeration Efficiency
- Electric Load Management / Shifting
- Energy Efficient / Premium Efficiency Motors
- Process Modifications/Improvements
- Pump / Motor System Optimization
- Pump Stations Operating Levels
- Rebuild Impellers/Casings of Old Pumps
- SCADA
- VFDs/VSDs
- Water Loss Minimization / Leaky Pipes

Pumping and aeration are typically the largest energy users and should therefore be analyzed carefully. According to the California Energy Commission (CEC) approximately 60 percent of electricity usage for wastewater treatment statewide is for aeration and pumping. The CEC further concluded that the energy savings potential for water and wastewater facilities in California (based on > 200 audits using audit processes developed by EPRI and HDR Engineering) was in the range of 15 to 33 percent with approximately equal contributions from process optimizations and equipment replacement. The Water Environment Federation (WEF) estimates 20 to 40 percent energy consumption reductions are likely.

Demand Response

The City can receive payments by agreeing to voluntarily reduce its electricity demand at the WPCP (and other City facilities). California utilities offer demand response (DR) programs to enable customers to contribute to energy load reduction during times of peak demand. Most DR programs offer financial incentives for load reduction during times of peak demand. Storms and heat waves, as well as periodic power plant repairs and maintenance, have the potential to affect California's supply and demand for electricity. When demand is high and supply is short, power interruptions can sometimes be the result. Building enough power plants to satisfy every possible supply and demand scenario is one possibility, but the cost and environmental impact of that would be tremendous.

DR programs are designed to be both fiscally and environmentally responsible ways to respond to occasional and temporary peak demand periods. The programs offer incentives to large electricity users that voluntarily participate by temporarily reducing their electricity use when demand could outpace supply. The DR programs have different requirements for load reductions during declared events. Consequences of not participating or not dropping load can range from no impact in a voluntary program to financial penalties that offset any rate savings in mandatory programs. Since participation in a demand response program could help the city generate additional reserve, further consideration is warranted and should be explored as part of a more detailed energy strategic plan.

Program Descriptions

There are a variety of DR programs offered either directly through PG&E or through intermediaries such as utility aggregators that the City could participate in. In addition, there are also incentive programs which PG&E's offers to promote the installation of equipment or control software (also referred to as enabling technologies) to support the various DR programs.

PG&E Programs

The “PeakChoice” and “Demand Bidding Program” (DBP) are the two main DR programs offered by PG&E.

PeakChoice is a flexible DR program that allows participants to decide how much (or how little) power reduction they are comfortable contributing, the timing of the reduction, the total number of days that reductions may be available to PG&E, how far in advance the participant must be notified of the reduction, and the acceptable duration of the reduction. There are two participation levels available, “PeakChoice Committed” and “PeakChoice Best Effort.” Annual incentive payment levels are based on the commitments made by the participant and generally range from $40,000 to $80,000 per MW offered for voluntary reduction.

DBP pays an incentive to reduce your electric load when notified of a demand response event day by PG&E. This is a relatively low-risk demand response program that allows you to submit load reduction bids for a DBP event, which can be called on a day-ahead or day-of basis. For accepted bids, participants will receive a credit equal to the qualified load reductions achieved for each hour of the event multiplied by the applicable incentive rate. The incentive rate is $0.50/kW per hour for day-ahead events and $0.60/kW per hour for day-of events. For any event, participants may elect to submit or not submit a bid. If a bid is submitted, participants can still choose to forgo reducing electric load without penalty.

Other PG&E DR programs that are currently fully subscribed include the Schedule Load Reduction Program (E-SLRP) and Base Interruptible Program (E-BIP). The City could apply to be placed on a waiting list for these programs.

Aggregator Programs

Another way the City could benefit from DR is to join a group of customers and pool its resources to achieve higher demand reductions and enjoy unique incentive structures. Acting as intermediaries between the participant and PG&E, aggregators offer DR program options not directly available through PG&E. Aggregators are independent third parties authorized to work with PG&E to reduce the state's energy usage during periods of peak demand, high wholesale-electrical prices, system constraints, and emergencies. Aggregator programs include:

- Aggregator Managed Portfolio (AMP) – This program consists of bilateral contracts with five aggregators that have been contracted to provide PG&E with price-responsive DR that PG&E may call at its discretion. Each aggregator designs its own program, and participants select the aggregator whose services best meet their needs.
- Base Interruptible Program (BIP) – The BIP aggregator pays an incentive to reduce the participant's facility load to or below a level that is pre-selected by the participant. This pre-selected level is called the Firm Service Level (FSL). At the order of the CPUC, the BIP has been capped at its current level of enrolled megawatts.
- Capacity Bidding Program (CBP) – This program allows enrollment with (or as) a third-party aggregator to reduce load. This program runs from May until October, paying monthly incentives for joining the program as well as incentives on event days.

Incentive Programs

PG&E also provides cash incentive payments for the installation of enabling technologies supporting DR through their Technology Incentive (TI) program. PG&E pays incentives of up to $125 per kilowatt (kW) to customers who achieve verified load reduction by installing certain recommended technologies that enable participation in DR programs. Customers can earn incentives for retrofits through the Customized Retrofit – Demand Response program (CR-DR) and for new construction through the Customized New Construction – Demand Response (CNC-DR) program.

CR-DR is a program for commercial, industrial, high-tech and agricultural customers. The program is administered by PG&E under the auspices of the CPUC, and provides financial incentives for the installation of enabling technologies that provide DR. Businesses that install and utilize DR equipment are rewarded with cash payments, based on the level of dispatchable peak load achieved.

CNC-DR is a program for commercial, industrial and agricultural customers who are dedicated to utilizing enabling technologies and who install DR measures in building process design and construction. The program is once again administered by PG&E under the auspices of the CPUC, and offers owners and their design teams incentives that follow the protocol outlined in the CNC-DR program material. These incentives include:

- Technical design assistance – Assistance from PG&E to analyze and design demand response measures into buildings and process systems
- Owner incentives - Up to $300,000 per project (subject to project incremental costs) to help offset the investment in energy-efficient building and design
- Design team incentives - Up to $30,000 per project to reward designers who meet ambitious energy efficiency goals

APPENDIX C – SELF-GENERATION TECHNOLOGIES

APPENDIX C – SELF-GENERATION TECHNOLOGIES

Cogeneration Technologies

Cogeneration is the simultaneous production of electricity and heat. Wastewater treatment plants typically use the generated heat for maintaining sufficient digester temperatures and other heating demands while using the electricity to run other plant processes. A description of reciprocating engines, gas turbines, and fuel cells is provided in this section.

Reciprocating Engines

Reciprocating engines which are capable of complying with the California Air Resources Board (CARB) and BAAQMD emission requirements were considered for this project. Lean burn engines are the only engine type applicable because they are the only field-proven technology which can meet the current BAAQMD emission rates when fueled with digester gas in the appropriate size range.

Reciprocating engines evaluated typically convert approximately 30 to 34 percent (as a percentage of fuel input energy) to electrical output and about 40 to 42 percent to recoverable jacket water and exhaust heat for a total overall efficiency of approximately 70 to 76 percent. Waukesha, Jenbacher, and Caterpillar engines offer lean burn, spark-ignited, turbo-charged, inter-cooled, clean burning gas engines and together have extensive digester gas burning experience.

Gas Turbines

In a gas turbine, there are three sections: a compressor, the combustor, and the turbine. The compressor compresses air and delivers it to the combustor. The air and fuel are mixed and burned in the combustor. The hot expanding gas spins the turbine. The energy absorbed by the turbine drives both the compressor section and a generator.

There are three main types of turbines: simple cycle, combined cycle, and recuperated. The simple cycle operates per the paragraph above; efficiency is typically 30 percent. A combined cycle turbine takes waste heat from the exhaust, creates steam, and drives a steam turbine. Combined efficiency for this combined cycle gas turbine is the highest for this technology at about 40 percent, but it comes at a high capital cost. A recuperated turbine uses a heat recovery unit to transfer the heat from the exhaust to preheat the air into the compressor to increase efficiency to about 38 to 39 percent. Capital cost isn’t as high as the combined cycle turbine, but size availability is limited.

Fuel Cells

Fuel cells utilize hydrogen present in methane, the predominant element of digester gas, as a fuel source in an electrochemical (battery-type) process. The process converts hydrogen and oxygen to water, and converts the elemental carbon from the methane into carbon dioxide. As an electrochemical process, it produces significantly less pollution byproducts than combustion technologies (approximately 1/30th the emissions generated by a gas turbine).

Fuel cells evaluated typically convert, as a percentage of fuel input energy, 45 to 47 percent to electrical output, and 22 percent to recoverable exhaust heat for a total overall efficiency of approximately 69 percent.

United Technologies Corporation (UTC), Fuel Cell Energy (FCE), and a relatively new company, Bloom Energy, are the only manufacturers of large-scale (greater than 30 kW) fuel cells utilizing biogas. FCE produces fuel cells in 300, 1,400, and 2,800 kW sizes and has many operating units, several on biogas. UTC produces 200-kW and 400-kW units but has limited positive experience operating on biogas. UTC is currently not selling fuel cells in California for DG or LFG fuel. Also, efficiencies of the UTC unit are significantly lower than the FCE unit. Bloom Energy only has one model, a 100 kW size fuel cell that is not available for use with digester or landfill gas. For these reasons, only the FCE unit was considered for this study.

Grant funding through the California Self-Generation Incentive Program (SGIP) is available for DG fuel cells up to a maximum size of 3 MW. The SGIP grant money for DG fuel cells is currently provided at a rate of $4,500/kW for the first MW, $2,250/kW for the second MW, and $1,125/kW for the third MW. The California Public Utilities Commission (CPUC), the state agency responsible for administering the SGIP, is currently considering making changes to the program. Advocates of fuel cells are promoting increasing the caps and the funding levels. If they are successful, additional fuel cells could be installed beyond the 1.4 MW PPA unit currently planned.

Fuel cells may be financed directly by the City or obtained from a private company utilizing a Public/Private Partnership (PPP). This is the method the City is currently anticipating for the planned 1.4 MW FCE fuel cell installation.

Solar Thermal

A solar thermal power plant works by concentrating the sun’s rays onto a tower filled with water. The water is heated and steam is produced to drive a steam turbine and make electricity. Areas best suited for this power generation technology are areas of high insolation (a measure of solar radiation energy) in a rural location (e.g. a desert). The area should be rural to prevent conflicts with the tower - which can be as tall as 500 feet, depending on the size of the installation. The land required is about 10 acres per megawatt, although the footprint can be made somewhat smaller at the expense of maintenance.

Projects less than 50 MW do not have to go through the California Energy Commission permitting process. Cost for producing electricity varies greatly from 20 to 30 cents per kWh, depending on the size of the installation and financing. The project could be used to produce hot water for heating the digesters, but there are cheaper ways of producing hot water. Two solar thermal companies were contacted; Abengoa and BrightSource Energy. Neither recommended this project. Given the low insolation values for the Bay Area and the high cost of the project, this option will not be given further analysis.

Organic Rankine Cycle

In this process, heat is used to heat a working fluid until it is vaporized. The high-pressure, hot, vaporized working fluid is then used to drive a turbine to produce electrical power. The low-pressure expanded vapor is then sent through a condenser to cool and condense it back to liquid form, where it is then boosted and sent back to repeat the cycle. There are several variations of this technology each requiring heat in the form of high temperature hot water, steam, or hot oil to heat the working fluid which is typically a liquid refrigerant. Since there will likely be surplus heat during most of the year as indicated in Figure 9, the City should conduct an evaluation of this and other surplus heat utilization technologies in the immediate-term as part of a detailed energy strategic plan.

Solar Photovoltaic

Photovoltaic (PV) systems convert light energy into electricity and is considered to be a 100 percent renewable energy source. Solar power was considered as a non-fuel alternative to the co-generation technologies. Because of the climate in the South Bay and the amount of land the City has available at their current site, solar power may be feasible for the City.

Three technologies were considered for installation on the site: fixed panels, single-axis tracking, and dual-axis concentrators. Fixed panels generate the least amount of electricity per panel, but have the advantage of low first cost and maintenance costs. Single axis tracking panels can generate the most energy per panel (up to 30 percent more than fixed panels), but the tracking units will require more maintenance. High efficiency panels have made gains on single axis panels, but production is not high enough. Concentrator PV cells focus the sun's rays on a very small but efficient solar panel. These units require a dual-axis tracking system to maintain the highest available output. Additionally, concentrator PV panels are highly dependent on the solar insolation. Based on the low solar insolation values for San Jose, fixed panels and single axis panels appear to be most cost effective. The land required is approximately 5 acres per MW.

Grant funding through the California Solar Initiative (CSI) is available for solar PV systems up to 1 MW size. Solar PV systems less than 50 kW are eligible for an up-front cash rebate known as the Expected Performance Based Buydown (EPBB) through CSI. Solar PV systems greater than 50 kW are only eligible for a Performance Based Incentive (PBI) through CSI which is paid monthly over the first five years of system operation based on actual system output. CSI incentives are distributed by the local program administrator using a step structure. The CSI program administrator for the City is PG&E, and they are currently in Step 7 which provides PBI payments at $0.19/kWh for Government/Non-Profit entities and $0.09/kWh for Commercial and Residential entities.

Based on preliminary quotations from solar companies, solar PV systems of 1 MW to 50 MW size appear feasible for the San Jose WPCP location through power purchase agreement (PPA) type of contracts. The City currently has a contract with Sun Edison to provide solar PV under a PPA arrangement. Since PPA contracts do not require any up front costs from the City, additional contracts should be explored further.

Wind

Many factors contribute to the cost and economic returns of a wind turbine installation. Power from a wind turbine is proportional to the cube of the site's average wind speed and is proportional to the square of the blade length. A small increase in blade length can increase energy capture in a cost-effective manner. Turbines only start producing electricity at the cut-in speed. Typical cut-in speeds vary from 7 to 10 miles per hour (mph). Life expectancy of a turbine is about 20 years.

Turbine availability/reliability is a major factor in project success. Turbine manufacturers may provide more robust warranties knowing that qualified operators and maintenance staff, like the ones at the plant, are on site.

As previously described, wind turbines could be obtained under a PPA arrangement, combining the available SGIP incentives with tax credits available only to the private sector. Wind turbines may be also purchased or leased, giving the owner flexibility in cash flow. If the owner purchases the wind turbine(s), they will own the Renewable Energy Credits, and the cost of the wind turbine can be partially offset by grant funding through the SGIP. SGIP grant money is available for wind power and fuel cells up to a maximum total of 3 MW for the two technologies combined. The SGIP grant money for wind power is currently funded at a rate of $1,500/kW for the first MW, $750/kW for the second MW, and $375/MW for the third MW. Low interest loans are also available from the California Loans for Energy Efficiency and Renewable Energy (3 percent interest) and the Federal Clean Renewable Energy Bonds (CREBS, 0 percent). Bonds will be available soon through the California State Energy Program, as funded by the Federal ARRA Stimulus Plan.

Engine-Driven Blowers

DG can be used to power blowers driven by reciprocating engines similar to the existing engine-driven blowers. When implemented, this is typically used for aeration of the secondary process. The primary advantage of this approach is that the fuel is directly converted to mechanical energy. With a typical engine-generator, the fuel is first converted to electricity, which powers an electric motor that drives the blower. By eliminating this extra step with engine-driven blowers, there is an increase in overall efficiency by about 5 to 10 percent.

The main disadvantage of the direct engine-driven blower is that the generated energy can only be used for a direct-driven piece of equipment compared to an engine-generator where it can be used throughout the plant. In addition, secondary process aeration demands will fluctuate so there will be periods where the engine blowers will need to be turned down, which reduces the engine efficiency depending on the load turn-down. This demand fluctuation may also result in periods where the DG is not fully utilized and may have to be flared. Like cogeneration engines, engine-driven blowers will also be subject to regulatory considerations highlighted in Section 2.6 of this PM. The WPCP currently has six engine-driven blowers in their Secondary Blower Building.

High Strength Organic Waste

To increase the amount of energy generated from digester gas on site, the City could install a facility to receive fats, oils, and grease (FOG). FOG would be added to the anaerobic digesters to boost DG production. With the addition of FOG, it may be possible to increase gas production by as much as 60 percent, with 20 percent of volatile solids loading as FOG per B&C TM 3.3 and B&C TM 4.4. Receiving FOG onsite would also provide an additional revenue stream from tipping fees. In addition to FOG, other high strength organics such as food waste or fructose can be added to the digesters. The City will be pursuing the installation of a FOG receiving facility as part of the digester improvements described in PM 5.2.

Two-Phase Anaerobic Digestion Of Green Waste

A two-phase anaerobic digestion process separates the “acid” and “methane” phases of digestion into separate tanks for improved efficiency of the overall process. This technology could be used as a method for digesting the City’s green waste and generating energy. While this technology may be promising for energy generation, this would require a change in operation for the wastewater treatment facilities to include green waste processing. In addition, without testing to prove otherwise, it would not be recommended to combine the green waste with the WPCP solid waste for co-digestion of the two waste products. Therefore, additional digestion facilities may need to be located at the WPCP and operation staff would be responsible for operation. This technology is not considered further in this analysis.

Algae

Algae photosynthesize and provide dissolved oxygen for BOD removal in wastewater treatment in addition to removing soluble nutrients and trace minerals. Once harvested downstream of the wastewater pond, algae become valuable biomass that can augment the municipality's energy portfolio. Fuels derived from algae oil have re-emerged as a topic of great interest in both the public and private sectors over the past several years as alternative energy sources have become increasingly popular. Funding for algae-to-energy research is supported by the Department of Energy (DOE), the Defense Advanced Research Projects Agency (DARPA), the National Renewable Energy Laboratories (NREL), international corporations (e.g. British Petroleum, Chevron, Boeing, etc), venture capitalists, and other private investors.

Current research indicates that while algae can be grown easily and wild strains can generate significant amounts of lipids (which can be converted to biodiesel), current technologies require more energy to harvest algae and extract the algae lipids than the energy in the lipids. The City should re-examine the potential for biodiesel production as the technology matures in the next 5 to 10 years.

Single-phase anaerobic digestion of algae yields less methane per pound of volatile solids than typical primary sludge and may result in digester complications or upsets. Methods for improving digestibility and biogas yield from algae biomass are currently under investigation. Two-phase digestion is one such method. Algae cell walls are resistant to bacterial degradation, which result in lower volatile solids reduction and less biogas yield. It is presumed the acid phase of the digestion process would assist in lysing the algae cell walls, making the algae contents (e.g. lipids) available for digestion in the methane phase.

In addition to providing treatment benefits in wastewater ponds, algae-based treatment systems can offer potential energy savings by using the algae biomass to produce energy. By offsetting fossil fuel purchase, algae-to-energy can help reduce greenhouse gas emissions.

Since algae growth in wastewater ponds is carbon-limited, alternative inorganic carbon sources such as carbon dioxide from industrial or cogeneration flue gas sources can be introduced into the ponds to increase algae growth, and thereby improve nutrient removal, increase DO, and provide additional biomass for anaerobic digestion and conversion to energy by methane cogeneration. However, costs for harvesting and processing algae biomass and its byproducts will also increase with increased algae growth due to carbon dioxide addition. As the markets for carbon credits develop, this may be a promising way to offset natural gas costs and possibly reduce greenhouse gas emissions.

Growing

Algae require sunlight to grow; however, as algae continue to grow, it becomes increasingly difficult for sunlight to reach algae in the deeper pond layers. For this reason, shallow paddle-wheel mixed raceway ponds (one meter deep or less) are typically selected (also known as high rate ponds). Photobioreactors are another option for algae production. Photobioreactors are designed to maximize exposure to light and increase algae productivity; however, these systems have not been implemented at large scales and require complex controls. Generally, the cost to build and operate photobioreactors exceeds the benefit of higher algae productivity.

Primary effluent is an ideal feed for high rate ponds because the algae will assist bacteria in secondary treatment by providing low cost dissolved oxygen, in addition to removing nitrogen and phosphorus. The biomass produced through this process would be available for conversion to energy. However, other liquid feeds can be used for algae production but may require supplemental nutrients to optimize algae growth. Also, depending on the feed, the pond effluent may require further treatment before it can be discharged with the rest of the treatment plant flow. For wastewater treatment plants, primary effluent is likely the best source of feed because the high rate ponds will offset treatment costs in addition to providing additional biomass for energy production.

Harvesting

Algae harvesting technologies include centrifugation, screening, coagulation and sedimentation, dissolved air flotation (DAF), and others. Bioflocculation is the most economically promising technology due to low energy requirements and minimal to no chemical addition. However, bioflocculation is not a proven technology for algae, and no commercial systems exist. DAF, with chemical coagulation is currently the most common algae harvesting method, but it is energy-intensive and requires significant chemical usage. The most appropriate harvesting technology also depends on the beneficial use of the algae biomass. Chemical coagulants that may be acceptable for anaerobic digestion may not be suitable for biodiesel production.

Cell Lysing

Organic Fuels Algae Technology is developing a lysing method that uses electricity to disrupt cell walls so the oil within the algae cells can be harvested. The proposed advantage is that it functions well on very low concentrations of algae (0.1-0.2 percent), but not at higher concentrations (e.g., 10 percent) achievable by DAF.

Hielscher Ultrasonics has developed an ultrasonic processor to lyse algae for enhanced oil extraction. Their largest unit (UIP16000) is capable of processing between 4 and 53 gpm. Parallel units can be used to treat higher flow rates.

Both of these lysing technologies would require piloting to optimize lysing performance and determine scale-up feasibility.

Extraction and Digestion

Three different methods for product extraction are undergoing research: pyrolysis, fermentation, and digestion. In pyrolysis, algae biomass is heated to high temperatures to produce combustible oil. Algae can also be fermented to convert the carbohydrates to ethanol. The cellulose in the algae normally ferments slowly and requires biological, chemical, or enzymatic breakdown to produce simple sugars for fermentation to ethanol. Commercial scale cellulosic ethanol plants are three to five years off. Yoshitani, et al., assert that algae to biofuels will follow a similar path of development as corn to ethanol. It has taken three decades for corn ethanol to grow to the size it is today (7.2 billion gallons per year production rate). An immediate use for the cellulose in the algae could be to dry the algae and combine it with biomass or coal in a power plant.

Piloting

The Obama Administration and the California Legislature have prioritized research and development for technologies to help the U.S. achieve energy independence. Through ARRA, SB 771, and other sources grant funding for pilot projects has become available through various State and Federal agencies (primarily, but not exclusively the CEC and U.S. DOE).

Since algae-to-energy systems still require further research and development, it is recommended that any algae-based treatment and/or algae biofuel system be piloted prior to full-scale implementation at the WPCP. Additionally, it would be beneficial for the City to complete a detailed evaluation and complete economic feasibility analysis for algae options at the WPCP as part of a long-term plan.

<u>Heat Generation Alternatives</u>

Gravity Film Heat Exchanger

In its most common use, a gravity film heat exchanger recovers heat from building wastewater and uses it to preheat water for a domestic hot water system. The design consists of a central copper pipe (that carries the warm wastewater) with copper pipe (carrying the cool domestic water) coiled around the central pipe. Heat is transferred from the wastewater passing through the central pipe to cold water simultaneously moving upward through the coils on the outside of the pipe. The key to this patented device was the inventor’s observation that wastewater clings in a film-like fashion to the inside wall of the pipe as it undergoes gravity flow in the open drain, and this warm, falling film transfers heat through the pipe wall to the incoming cold water. See Figure C1.

This technology is highly dependent on the temperature of the wastewater: the hotter the sewage coming out of the building, the warmer the preheated water will be. These systems are installed as close to the main sewage connector as possible. The temperature drop of the wastewater will be very close to the temperature rise of the cold domestic water.

As the wastewater travels through the collection system, it cools. The incoming temperature of the plant varies between 61 and 75°F into the plant, depending on season. Under ideal conditions, water flowing through the domestic coils could only be heated up to this temperature, and not higher, making this technology unsuitable for applications at the WPCP such as sole-source district hot water or hot water for heating sludge. As a result, this technology was not evaluated further.

Heat Pump

One of the technologies discussed during the TAG meeting was a water source (water to water) heat pump that could be used to extract heat from the secondary or tertiary effluent streams at the WPCP. A heat pump operates on the principle of adding work into a system to move the heat from one source into another (e.g. from the effluent stream to the WPCP hot water loop). Standard heat pumps are available in sizes of 0.5 to 25 tons, while specialty industrial water source heat pumps for producing hot or chilled water are available in sizes between 1 and 5,000 tons.

A 60-million gallons per day (mgd) wastewater treatment plant in Helsinki, Finland, supplements a district chilled water/hot water system with a heat pump. Raw wastewater is pumped through fine screens, and then on to a heat exchanger. A second loop pumps a glycol/water mixture through the evaporator coils. The heat pump circulates refrigerant through its system and onto the warm condenser loop. The district hot water loop flows through the condenser heat exchanger and pumps hot water for heating to the City. See Figure C2.

Offsite Sources of Power and Heat

Currently, the plant buys natural gas and portion of electricity from PG&E and landfill gas from the Newby Island Landfill. Although the landfill is estimated to produce gas until 2040, the existing agreement for purchase of landfill gas expires in 2017 and may not be economically attractive after that. The WPCP purchases landfill gas at a discount (25 percent ±) over the current PG&E natural gas price. The nearby Zanker Road landfill and distant Kirby Canyon landfill currently do not have a gas collection system. Landfill gas from these two landfills may not be economically viable due to the nature of the wastes in the landfill (Zanker Road) and the distance from the plant (Kirby Canyon is 23 miles to the south).

There are other potential options for purchase of waste heat, including from the planned Zanker Road Biogas facility at the Nine Par Site, and the Calpine power plant. The facility could produce up to 1.73 MW of electricity and 6.3 MMBTU/hr of heat, which can be used for heating the digesters. Carollo met with Calpine and discussed the potential of the WPCP using waste heat from their facility. Calpine has not yet responded, therefore it appears that they are not currently interested in any near-term partnering with the City. However, the City should continue discussions with Calpine to identify potential partnering opportunities should Calpine switch operations to a non-peaking plant in the future.

The City has also obtained several proposals from vendors offering to convert organic materials into energy and compost. These proposals are under review now and may offer additional opportunities for energy availability to the WPCP.

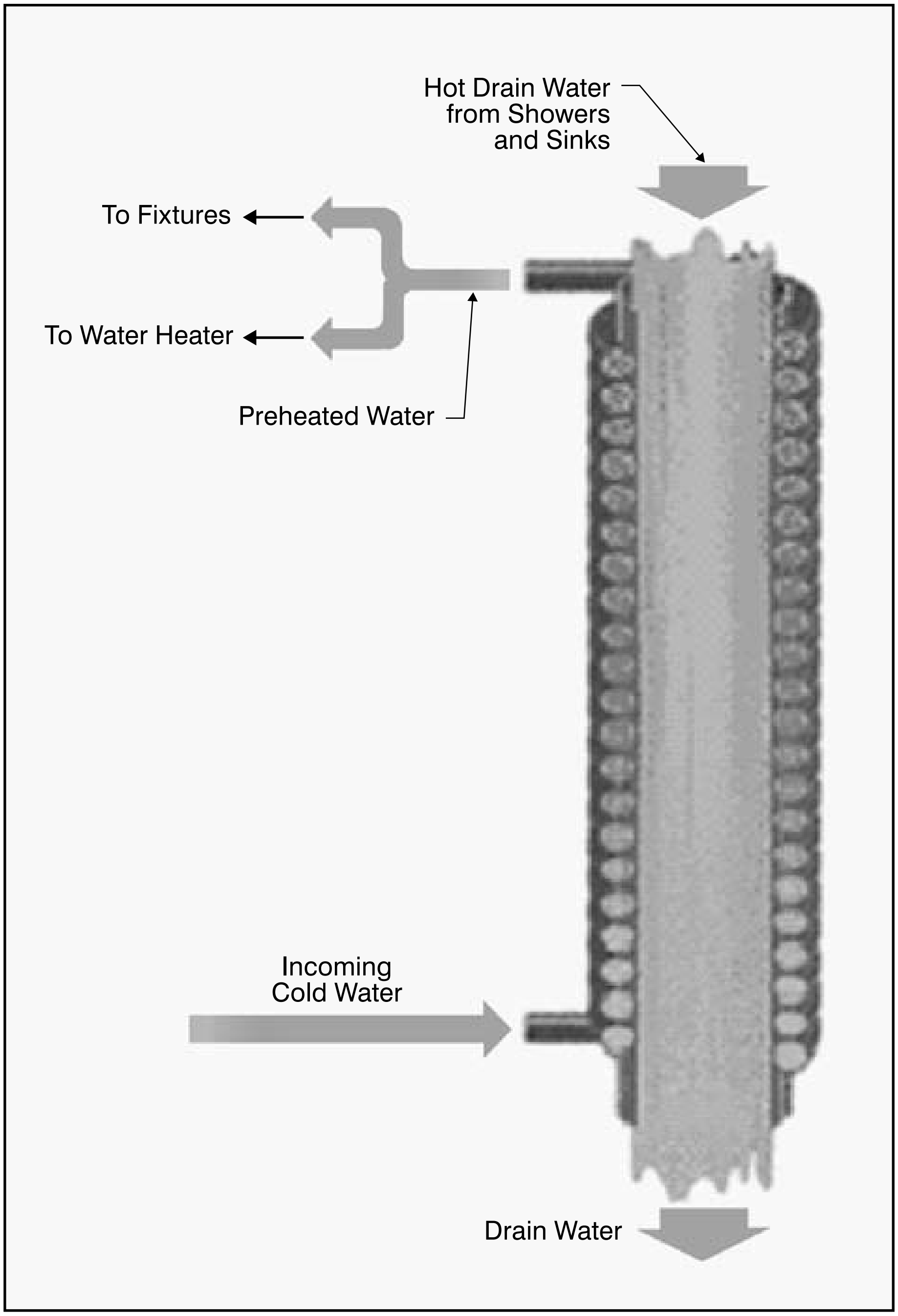

Figure C1
GRAVITY FILM HEAT EXCHANGER
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

sj610f9-7897.ai

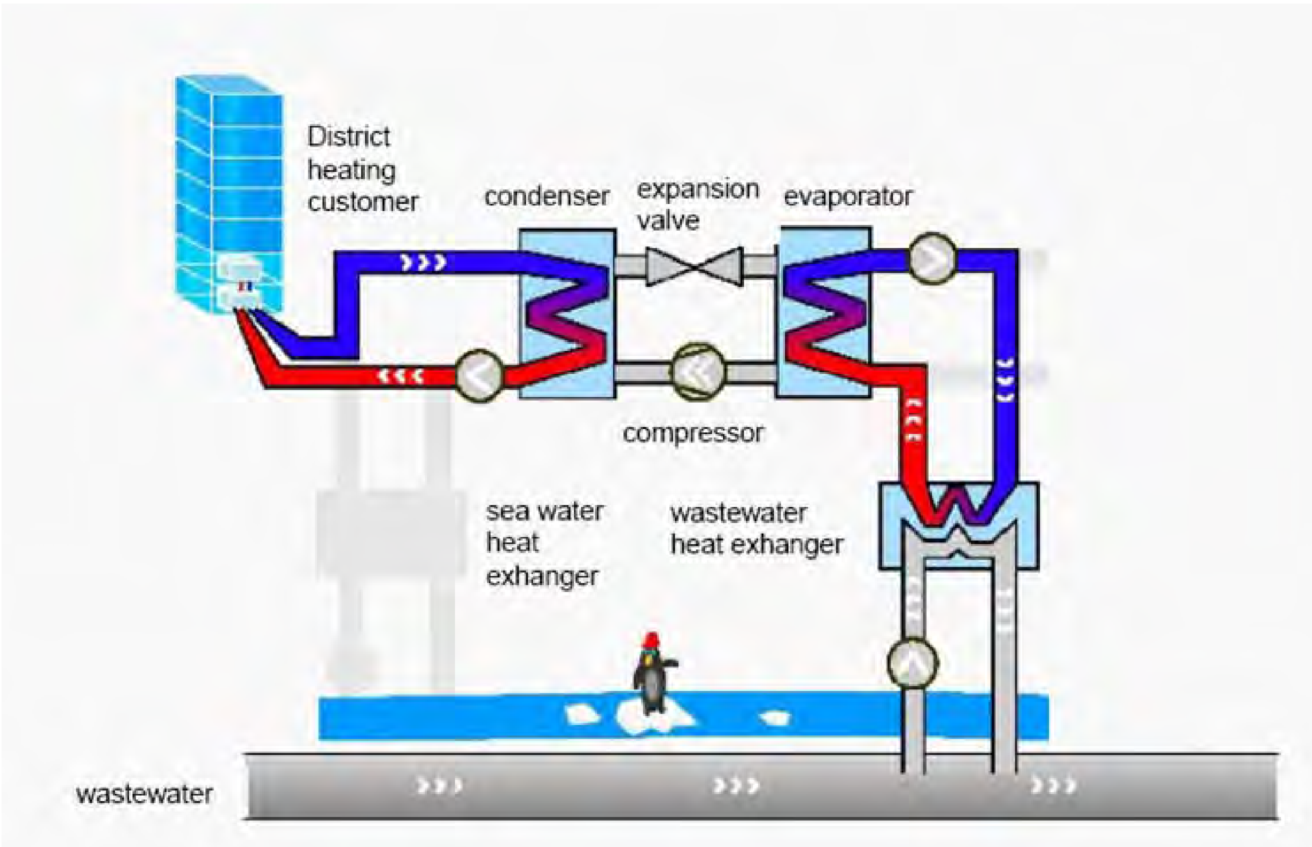

Figure C2
HELSINKI'S HEAT PUMP FOR DISTRICT HOT WATER
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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APPENDIX D – ALTERNATIVE ANALYSIS

APPENDIX D – ALTERNATIVE ANALYSIS

Cogeneration Alternatives

Description

Four alternatives for self-generation were evaluated for future replacement of the Building 40 engine-generators. These alternatives are summarized in Table D1. Alternative 0, the base case alternative, is currently under way. This alternative involves operating two of the existing three engines in Building 40 and purchasing electricity from a fuel cell under a PPA.

Table D1 Alternatives
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Alternative 0 (Base Case)	Two 2,800 kW Building 40 engines One 1,400 kW fuel cell (PPA)(1)
Alternative 1 (Add New High-Efficiency Engines)	Two 2,398 kW high-efficiency engines One 1,400 kW fuel cell (PPA)(1)
Alternative 2 (Add New Gas Turbines)	One 4,600 kW recuperated gas turbine(2) One 1,400 kW fuel cell (PPA)(1)
Alternative 3 (Add Additional Fuel Cells)	One 2,800 kW fuel cell One 1,400 kW fuel cell One 1,400 kW fuel cell (PPA)(1)

Note:
(1) Startup anticipated by the beginning of January, 2012.
(2) Turbines sized based on current product offering for recuperated gas turbines.

Similarly, Alternatives 1 through 3 involve installing new high-efficiency engine-generators, gas turbines, or additional fuel cells.

Criteria and Financial Assumptions

Alternatives were evaluated based on a 30-year life cycle analysis (2011-2040). Only high power scenarios were considered. Average energy demand in 2011 was assumed to be 10.5 MW power and 17.4 MMBTU/hr heat based on the calculated demands from Tables 5 and 6. Average energy demand in 2040 was then assumed to be 16.7 MW power and 16.0 MMBTU/hr heat. Financial assumptions are presented in Table D2.

Table D2	Financial Assumptions San José/Santa Clara Water Pollution Control Plant Master Plan City of San José
Utility price escalation	
Low scenario	1.7% annually(1)
High scenario	4% annually(2)
Escalation	3% annually
Real Interest Rate	2% annually
O&M escalation	3% annually
O&M Rates	
Existing engines	$0.031/kWh
New engines	$0.020/kWh
Gas turbines	$0.020/kWh
Fuel cells	$0.035/kWh
Fuel treatment	$0.010/kWh
Green power credits	$0.03/kWh

Notes:
(1) Annual escalation based on DOE projections.
(2) Annual escalation based on PG&E historical trends.

Project capital costs were generated for each alternative and included costs for selective catalytic reduction (SCR) systems where necessary to ensure that the WPCP could meet tighter air quality requirements in the future. Project capital costs also include credits for grant funding available through the SGIP where applicable. Table D3 provides a summary of these project capital costs.

Table D3 Cogeneration Project Capital Costs
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Alternative	Capital Cost
Alternative 0 (Base Case)	$5,640,000
Alternative 1 (Add New Engines)	$22,090,000
Alternative 2 (Add New Turbines)	$22,510,000
Alternative 3 (Add New Fuel Cells)	$36,230,000(1)

Notes:
(1) Includes grant funding through the SGIP.

Solar PV Generation

Solar PV Generation

The WPCP also has land available for installation of a solar PV facility either as multiple blocks throughout the site or as a line arranged around the perimeter of the site just inside the fence line. Budgetary prices for direct purchase were obtained for three equipment representatives and are summarized in Table D4. Prices were obtained for fixed and single axis tracking panels for 1, 5, 10, and 50 MW installations. Prices were not obtained for a concentrator, as this technology is not cost-effective due to low insolation values. Fixed panels require 4 acres per megawatt while single axis trackers require between 5 and 6 acres per megawatt.

Under this direct purchase approach, the calculated cost per kWh in Table D4 is more expensive than what the City is currently paying ($0.09/kWh). The cost per kWh under a solar PPA approach would likely be even more. However, if the City is able to work out an agreement with a third party to take advantage of the 30 percent ITC, the average energy cost for a 1 MW facility could be equal or less to what the City is currently paying. In addition, current industry trends show that solar PV panel costs continue to decrease. Therefore, the City should conduct an evaluation for direct purchase and installation conducted through a third party for a 1-MW solar PV facility in the immediate-term and additional solar PV systems in the future as part of a detailed energy strategic plan.

Energy Storage

Solar generation technologies can only provide power when the sun is shining. Therefore, it is recommended that the WPCP further investigate how solar power could be best integrated into the overall energy management plan. The options include:

- Using the power as it is delivered (i.e. during the day when the sun is shining)
- Limiting the size to 1 MW and net metering
- Installing an energy storage system to enable discharge of energy during the night when solar generation is not available
- Commercially available battery storage technologies are not economically feasible at this time, but may warrant future consideration once prices come down. SGIP funding is available for advanced energy storage (AES) systems when coupled with an SGIP eligible fuel cell or wind project. Since the City is planning to install a 1.4-MW fuel cell and may find a wind project to be potentially attractive, it may be possible to build storage in the overall system through using the SGIP AES funding opportunity.

Table D4 Summary of Solar PV Prices
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Supplier/ Manufacturer	Panel type	Size (MW)	Estimated Installed Cost	Estimated Project Costs (1)	Energy Generated (kWh/year)	Average Energy Cost – Low (2)(4) ($/kWh)	Average Energy Cost – High (3)(4) ($/kWh)
Solar City (First Solar Panels)	Thin film, fixed	1	$5,500,000	$6,325,000	1,575,000	$0.15	$0.16
		5	$25,000,000	$28,750,000	7,875,000	$0.14	$0.15
		10	$50,000,000	$57,500,000	15,750,000	$0.15	$0.15
		50	$250,000,000	$287,500,000	78,750,000	$0.15	$0.15
Conergy (First Solar Panels)	Thin film, fixed	1	$3,800,000	$4,370,000	1,575,000	$0.10	$0.11
		5	$21,800,000	$25,070,000	7,875,000	$0.13	$0.13
		10	$41,250,000	$47,437,500	15,750,000	$0.12	$0.12
		50	$200,000,000	$230,000,000	78,750,000	$0.12	$0.12
Sunpower	Mono-crystalline, single axis	1	$5,960,000	$6,854,000	1,800,000	$0.14	$0.15
		5	$32,600,000	$37,490,000	9,000,000	$0.17	$0.17
		10	$60,000,000	$69,000,000	18,000,000	$0.15	$0.15
		50	$288,000,000	$331,200,000	90,000,000	$0.15	$0.15

Notes:

(1) Estimated cost is vendor installed cost plus 15% for design and administration.

(2) Low scenario includes CSI PBI funding at current PG&E Step 7 rate and is applied to the first 5 years of generation.

(3) High scenario includes CSI PBI funding at future PG&E Step 10 rate and is applied to the first 5 years of generation.

(4) Average energy cost over 25 years. Costs may decrease if the project is done by a private third party who can make use of a 30% ITC and depreciation.

In addition, the California Independent System Operator (CAISO) offers incentives to owners of AES systems who agree to participate in their frequency regulation market. Specifically, CAISO must continuously balance the electricity supply with load to maintain the frequency at 60 Hz. This is done by decreasing or increasing generator power output in response to frequency deviations. AES systems have the ability to balance generation (discharge state) and load (charge state) to maintain frequency. Thus, CAISO has significant interest in working with AES system owners to utilize these capabilities of AES systems. For the 2008 year, CAISO provided average rates of $15.67/MW and $18.94/MW for frequency regulation up and frequency regulation down respectively. Participation in these markets could offset much of the high capital cost for installing an AES system. Therefore, further consideration of AES technologies is warranted and should be included as part of a detailed energy strategic plan.

Another energy storage option is through high-pressure DG storage. With this system, the WPCP could meet their demand during the day with the solar facility and store the DG generated. This stored gas could then be utilized in cogeneration equipment at night when the solar facility is not able to generate power. This system will provide the added benefit of helping with seasonal and diurnal variability in DG production by enabling storage of gas during high production periods and use during low production periods.

Wind Generation

Wind velocity data for about the last two years was obtained from the monitoring station on top of the Secondary Blower Building. Average wind speed for the plant was 4.4 mph with a standard deviation of 3 mph. Average wind speed only tells part of the story. To give a better idea of wind speed, a wind speed distribution chart was created, (see Figure D1).

The wind speed distribution chart shows what percentage of time the plant receives each wind speed. It shows that 25 percent of the time the wind speed is above the cut-in speed, the speed at which a turbine starts generating electricity. Therefore, 75 percent of the time the turbine will not be generating electricity. Despite this, the WPCP may still be able to install wind generation through an alternate ownership arrangement. Table D5 provides the comparative costs of a 1-MW wind turbine under three scenarios.

While the private partner may not be willing to allocate all of the benefits it is eligible for to offset project costs, a properly structured competition usually results in the private companies offering to share the majority of the benefits with the City.

Thus, wind energy developed in a PPP mode could still be a feasible part of the City's energy management strategy even though the WPCP's available wind resource is lower than the wind speed that is considered ideal. However, careful evaluation of the wind turbines effect on the bird population at the WPCP must be conducted before a firm decision to implement wind energy is made. In addition, further consideration is warranted should future advancements in wind turbine technology allow for power generation at lower cut-in speeds.

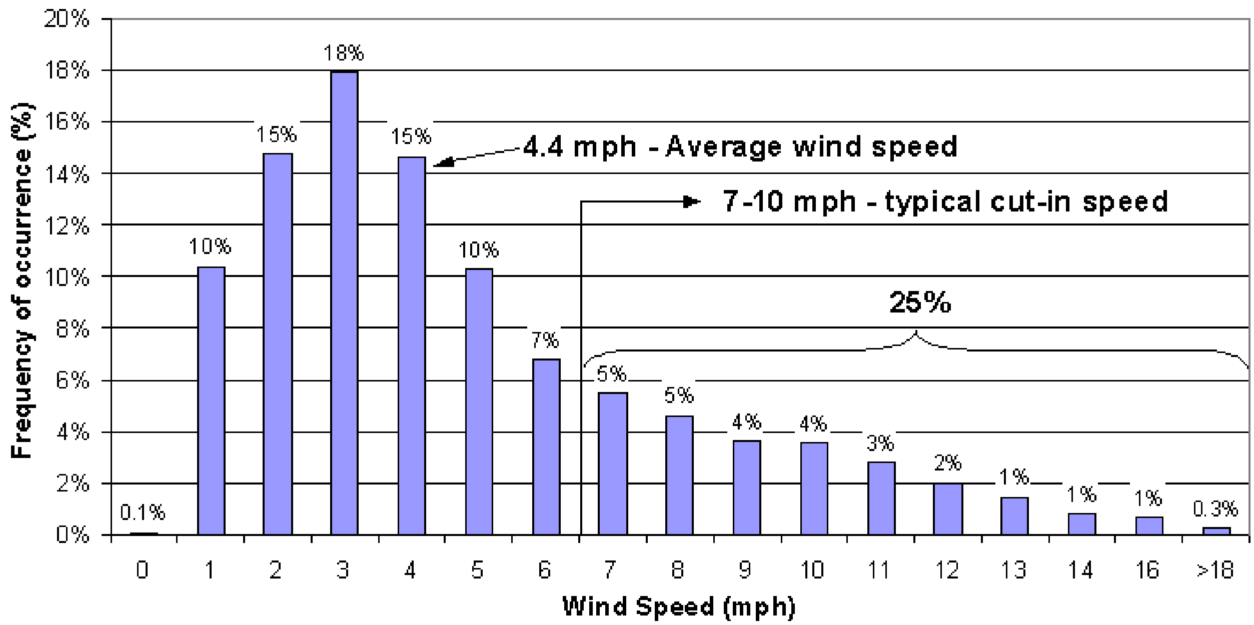

Figure D1
WIND SPEED DISTRIBUTION
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ

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Table D5	**Onsite Electrical Power Generation Capacity San José/Santa Clara Water Pollution Control Plant Master Plan City of San José**		
	Alternative		
Description	**City Owned**	**City Owned with SGIP Grant Funding**	**Public/Private Partnership**
Wind Turbine Project Cost	$3,600,000	$3,600,000	$3,600,000
Private Company Fee	$0	$0	$400,000
Total Installed Cost	$3,600,000	$3,600,000	$4,000,000
SGIP Grant	$0	<$575,000	<$575,000
ITC	$0	$0	<$1,200,000
Accelerated Depreciation	$0	$0	<$400,000
Net Project Cost	$3,600,000	$3,025,000	$1,425,000

Note:

(1) Assumes the 1.4 MW fuel cell PPA will proceed as planned, the SGIP grant would be increased to $1.5 million if the 1.4 MW fuel cell PPA project does not move forward.

Heat Pump

As previously noted, a wastewater treatment plant in Helsinki, Finland has been successful in supplementing a district chilled/hot water system with a heat pump. Helsinki's heat pump has a heating capacity of 307 MMBTUh (90MW) and delivers hot water at 190°F. The coefficient of performance (COP) of the system is 3. In 2006, the system cost between $36 and $42 million (30-35 million Euros) to install. It is manufactured by Friotherm, a European company specializing in industrial chillers and heat pumps. Based on the COP above, energy input to the unit is 45 MW. Assuming district heating for 3 months per year and an electricity rate of $0.0922/kWh, the cost to operate the unit is $9 million. The cost to operate a NG fired condensing boiler and produce hot water at the same rate would be $7.3 million.

Although Helsinki used raw sewage, the WPCP could use secondary or tertiary effluent. By using higher quality wastewater effluent, the screening system and its associated maintenance can be eliminated, saving first costs and operating costs. For the WPCP, using 110 mgd average flow, about 600 MMBTUH can be recovered with an energy input of about 90 MW. To recover 60 MMBTUh at about 180°F, 9 MW of electric power would be needed. The power cost for 9 MW of electricity at 12 cents/kWh would be $9.46 million per year. If 60 MMBTUh of heat is produced in a condensing boiler by using NG, the NG cost at $0.75 per therm would be $3.94 million per year. Therefore, implementation of a heat pump system at the WPCP is not economically viable and was not evaluated further.

APPENDIX E – FUNDING SOURCES

APPENDIX E – FUNDING SOURCES

City Owned Projects

Small capital energy projects such as installation of low cost energy efficient pumps, motors and lights and projects such as the digester improvements which do not directly generate electricity and therefore may not be eligible for renewable energy related tax credits are best financed, owned, and operated directly by the City. These projects can be financed either as part of the overall WPCP CIP programs, or through special energy financing vehicles such as the California Energy Commission loan program, PG&E's anticipated on-bill financing program or Qualified Energy Conservation Bonds.

**Table E1 Funding Sources for Energy Projects
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José**

Funding Source	Description	Recommended Use of Funding
CEC Low Interest Loans	CEC offers 1% and 3% interest loans that must be paid back within a maximum timeframe (~15 years)	Use for small and medium-sized cost-effective projects. These loans have a low interest rate but require upfront capital and have a maximum payback period
Energy Efficiency Conservation Block Grant (EECBG)	ARRA sponsored grants available to local governments to implement energy saving programs	Use for planning and implementing programs that may not result directly in cost savings. There is no minimum efficiency or payback period requirement. Also use for capitalizing and/or securing revolving loan funds or finance district funds. Due to typically longer payback period of renewable energy projects, this is also an alternative funding source for renewable energy projects if a PPA isn't feasible
Energy Service Company (ESCO) Financing	ESCOs offer financing services where they pay the capital cost of an efficiency upgrade and the cities then pays the ESCO a fixed rate for energy for a negotiated period of time	Use for financing a large number of energy efficiency projects, when no other source of capital is available. These tend to be more difficult contractual arrangements – similar to the PV PPA projects, ESCOs require access to equipment in order to ensure maintenance and operations are optimized to maximize ESCO's profits. ESCOs often own the equipment for a period of time
Finance Districts (backed by	Allows property owners to finance investments in energy efficiency or renewable energy projects	Use for supporting community-wide equipment financing programs. Third party program financier typically assumes the majority of the program planning and

Table E1	Funding Sources for Energy Projects San José/Santa Clara Water Pollution Control Plant Master Plan City of San José	
Funding Source	**Description**	**Recommended Use of Funding**
3rd party financiers)	and make payments through a line item on their property tax bill. Financial obligation is tied to the property itself if the property ownership changes	design, marketing, and implementation responsibilities; reducing the agency's in-house program staffing requirements
Build America Bonds	These are taxable bonds that can be issued by the City. The Federal government subsidizes 35% of the interest cost	Since these bonds are not limited solely to energy projects and are authorized for wastewater treatment facilities, they may be an appropriate financing vehicle for the entire project
Municipal Revolving Loans	Cities develop a fund that can be used to finance energy projects at municipal facilities. The fund is replenished through savings on energy bills	Use for small and medium-sized projects that have long payback periods or would otherwise not be attractive to outside financing programs. Requires the development of a payment process and payment tracking system
On-bill Financing (PG&E pilot OBF program expected in summer of 2010)	Utility finances capital expenditure, and building owner repays the utility through a line item on the utility bill	Depending on interest rate, use for a range of projects. If interest rate is high, use for relatively small projects because repayment process easy and small projects may not justify administrative burden of maintaining stand-alone loans. Depending on interest rates, may also be a good fit for larger projects
Power Purchase Agreements (PPAs)	PPA provider finances the installation of energy efficiency and renewable energy systems and building owner purchases electricity from the PPA provider at a fixed price for a negotiated length of time	Use if agency has renewable energy projects and/or projects that can bundle an energy efficiency portfolio with renewable electricity project installations
Qualified Energy Conservation Bonds (QECBs)	Low interest bonds available to large local governments for qualified projects including projects that save energy	Use for large, expensive projects. These have a low interest rate and do not require upfront capital

Public-Private Partnerships (PPP) Projects

Large capital energy projects such as wind, solar, and fuel cells that produce power for onsite use are often best financed in conjunction with a private sector partner to incorporate the tax benefits available to a private company into the project financing. These type of projects (such as the planned Fuel Cell PPA project) may also be eligible for additional grant funding through California's SGIP and CSI programs. The SGIP program allows the use of both tax credits and the SGIP grant providing a significant offset to the initial project cost.

Private Sector Owned Projects on City Property

Large capital energy projects that produce power for sale are best financed, owned, and operated by the private sector. This type of arrangement would enable the City to make beneficial use of the renewable energy field included as part of the land use plan for the area surrounding the WPCP without having to make a capital investment. Instead, if such a project could be located on the designated property, developers would be willing to pay the City for use of the property. For every 100 acres of property made available, 20 to 25 MW of solar PV or 15 to 20 MW of wind power could be developed. Based on our experience in other California projects, this could bring $50,000 to $200,000 or more in annual lease payments (typically paid as a base, ground lease payment plus a percentage of power sales revenues) to the City.

Pilot Projects

There are also some advanced energy technologies such as algae use for digestion or bio-fuels production that may show promise, but are not yet commercially proven. Currently there is a significant amount of demonstration grant funding available and it is projected that this funding will continue to be available for the next few years. However, since there are many entities interested in securing funding for their projects, the City should carefully monitor and consider these demonstration grant opportunities and be prepared to act as they tend to disappear just as quickly as they arise.

APPENDIX F – FOG, SCUM AND GREASE LOADING AND GAS PROJECTIONS

APPENDIX F – FOG, SCUM AND GREASE LOADING AND GAS PROJECTIONS

The FOG, scum and grease estimates are based on Brown and Caldwell projections as outlined in TM 3.3 – Design Criteria for Digester Modifications and Gas System Improvements. The projections for 2030 were based on:

- FOG average design value of 80 percent of the 30-year FOG market per Environmental, Engineering and Contracting Inc. (EEC) report.
- Plant scum and grease average design value of 29% more than the current plant scum and grease of 153,000 gallons per year

The 2030 projections were prorated linearly from 2012 to 2030. After 2030 and through 2040, it was assumed that the volumes of FOG, scum and grease did not increase i.e. FOG, scum and grease build-out flows occur in 2030.

Table F1 FOG, Scum and Grease Design Flow and Gas Production Projections
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Year	FOG, Scum and Grease Loading (lbVS/day)	FOG, Scum and Grease Gas Production (kscf/day)(1)
2009	0	-
2010	0	-
2011	0	-
2012	4,147	81
2013	8,295	162
2014	12,442	243
2015	16,589	324
2016	20,737	405
2017	24,884	486
2018	29,032	568
2019	33,179	649
2020	37,326	730
2021	41,474	811

Table F1	FOG, Scum and Grease Design Flow and Gas Production Projections San José/Santa Clara Water Pollution Control Plant Master Plan City of San José	
Year	**FOG, Scum and Grease Loading (lbVS/day)**	**FOG, Scum and Grease Gas Production (kscf/day)(1)**
2022	45,621	892
2023	49,768	973
2024	53,916	1,054
2025	58,063	1,135
2026	62,211	1,216
2027	66,358	1,297
2028	70,505	1,378
2029	74,653	1,459
2030	78,800	1,541
2031	78,800	1,541
2032	78,800	1,541
2033	78,800	1,541
2034	78,800	1,541
2035	78,800	1,541
2036	78,800	1,541
2037	78,800	1,541
2038	78,800	1,541
2039	78,800	1,541
2040	78,800	1,541

Notes:

(1) – Based on a FOG gas production rate of 19.6 scf/lb VS destroyed per Brown and Caldwell assumptions.

APPENDIX G – HEAT DEMAND ANALYSIS

APPENDIX G – HEAT DEMAND ANALYSIS

Solids Heat Drying Demand

The following heat demand for solids drying (Table G1) was determined based on the solids projections as well as assumptions for solids characterization (%TSS, %VSS and volatile solids reduction) provided by Brown and Caldwell . These assumptions were the same assumptions used in the Master Plan PM 5.2.

Table G1 Heat Demand Calculations for 20% Solids to heat Drying for 2040
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

		Projected Solids			
Description	**Year**	**Annual Average (lbs/day)**	**Peak Month (lbs/day)**	**Units**	**Notes**
TO DIGESTER	2040	412,000	548,000		% TSS = 5.5%
					%VSS = 81 %
	Flow =	0.90	1.19	mgd	VSD = 54%
	Volatile Solids =	333,720	443,880	lbs/day	
	Fixed Solids =	78,280	104,120	lbs/day	
	VS destroyed =	180,209	239,695	lbs/day	
	VS remaining =	153,511	204,185	lbs/day	
	Total Solids remaining =	231,791	308,305	lbs/day	(to lagoons)
FROM DIGESTER TO LAGOON	% solids in digester effluent =	3.1	3.1	%	
	Fixed Solids =	78,280	104,120	lbs/day	VSD = 30%
	VS destroyed =	46,053	61,255	lbs/day	
	VS remaining =	107,458	142,929	lbs/day	
	Total Solids remaining =	185,738	247,049	lbs/day	(to dewatering)
	% solids in digester effluent [1] =	2.5	2.5	%	
DEWATERING	Dewatered solids =	25%	25%		
	Dewatered solids to drying =	0.11	0.15	mgd	
	Recycle to head works =	0.79	1.05	mgd	
	% of total solids flow to heat drying =	20%	20%		

Table G1 Heat Demand Calculations for 20% Solids to heat Drying for 2040
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

		Projected Solids			
Description	**Year**	**Annual Average (lbs/day)**	**Peak Month (lbs/day)**	**Units**	**Notes**
TO HEAT DRYING	Heat drying : Solids dried to	80%	80%		
	Final dried solids flow rate =	0.01	0.01	mgd	
	Water evaporated in dryer =	0.02	0.02	mgd	
		16,666	22,168	gpd	
		138,999	184,882	lbs/day	
	BTU required for drying(2) =	236,297,450	314,298,550	BTU/day	
		9.85	**13.10**	**MMBTU/hr**	
	Heating value of NG =	1000	1000	BTU/scf	
		164.10	218.26	scfm	
	Therefore NG savings =	**236,297**	**314,299**	**scfd**	

Notes:
(1) Assumes that flow from the lagoons equals the flow into the lagoons
(2) Assumes 1,700 BTU per lb water

Seasonal Heat Demand

Based on the average heat demand and seasonal heat demand established in the heat balance developed by CDM, monthly heat demand factors were established (Table G2 below). These monthly heat demand factors were used to project seasonal heat demand for 2040 (build-out) without heat drying. The seasonal heat demand for 2040 is also shown in Table G2 below. The monthly average heat drying demand was then superimposed on the 2040 projected seasonal heat demand and compared to the average supply available in 2040. Figure G1 shows a plot of the 2040 average and seasonal heat demand, both with and without heat drying, as well as the 2040 heat supply projection. The figure indicates that the heat supplied will always be able to meet the average heat demand required for drying of 20% of the dewatered solids. As a result natural gas will not be required even during the colder months of the year.

Table G2 Seasonal Heat Demand Projections for 2040
San José/Santa Clara Water Pollution Control Plant Master Plan
City of San José

Month	2010 Seasonal Heat Demand			2040 Seasonal Heat Demand[2]		2040 20% Heat Drying Average Month	2040 Total Heat Demand including 20% Heat Drying
	MW	MMBTU/hr	Monthly Factor[1]	MW	MMBTU/hr	MMBTU/hr	MMBTU/hr
Jan	6.40	21.8	1.25	7.02	23.9	9.9	33.8
Feb	6.52	22.2	1.27	7.15	24.4	9.9	34.2
Mar	6.73	23.0	1.31	7.38	25.2	9.9	35.0
Apr	5.93	20.2	1.16	6.50	22.2	9.9	32.0
May	4.94	16.9	0.96	5.42	18.5	9.9	28.3
Jun	4.23	14.4	0.82	4.64	15.8	9.9	25.7
Jul	3.85	13.1	0.75	4.22	14.4	9.9	24.3
Aug	3.86	13.2	0.75	4.23	14.4	9.9	24.3
Sep	3.90	13.3	0.76	4.28	14.6	9.9	24.4
Oct	4.27	14.6	0.83	4.68	16.0	9.9	25.8
Nov	4.89	16.7	0.95	5.36	18.3	9.9	28.1
Dec	6.05	20.6	1.18	6.64	22.6	9.9	32.5

Notes:

1. The monthly factors were derived from the ratio of the seasonal heating demand to the monthly average heat demand in the WPCP heating data from Appendix A of the Heat Balance Study for 2010.
2. Determined based on the monthly factor multiplied by the 2040 average heat demand of 19.2 MMBTU/hr.

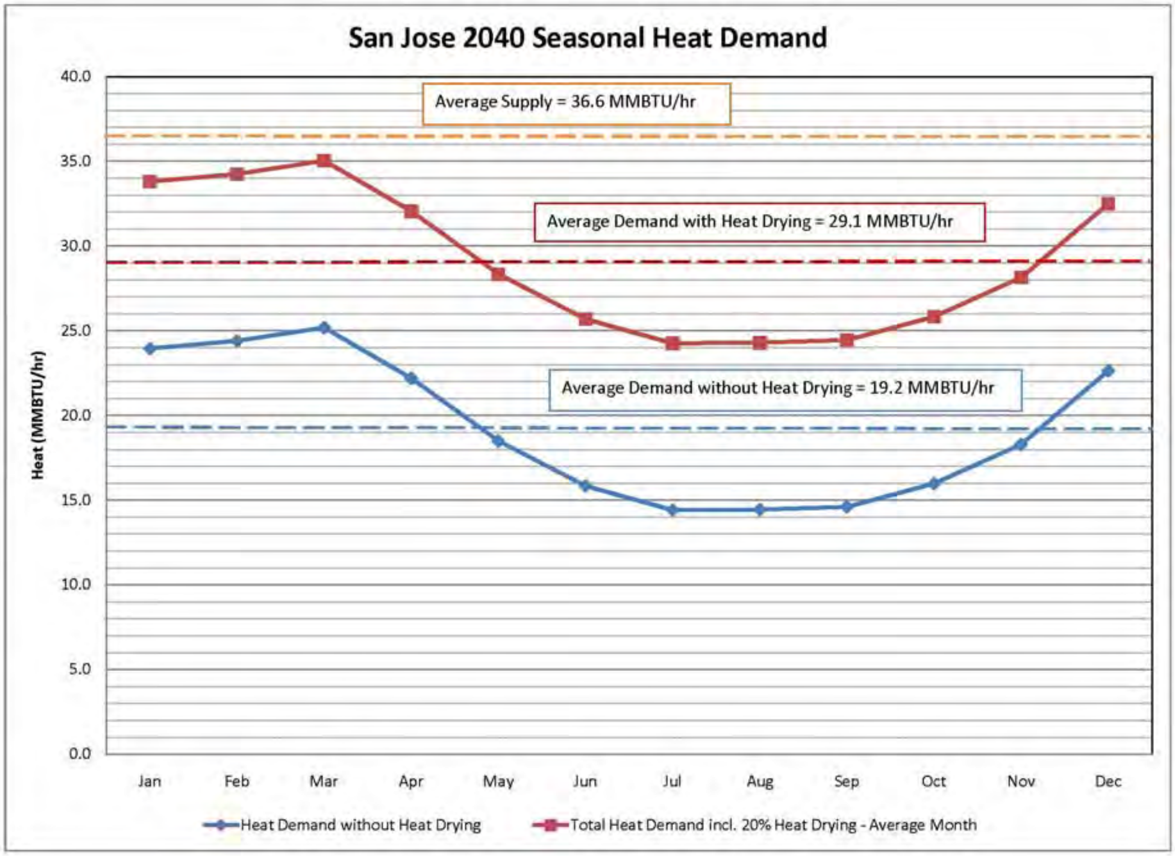

Figure G1
2040 SEASONAL HEAT DEMAND
SAN JOSÉ/SANTA CLARA WPCP MASTER PLAN
CITY OF SAN JOSÉ