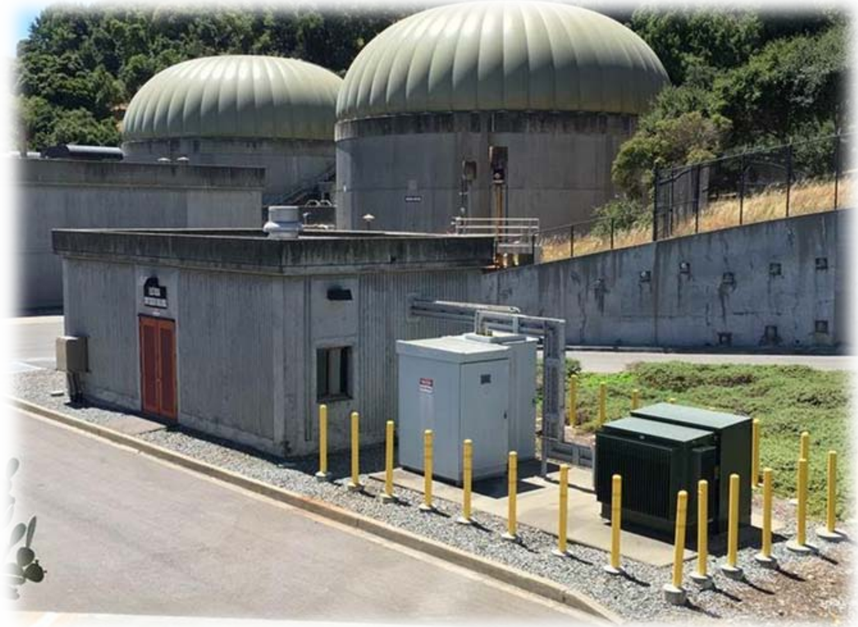
Interconnection Agreement Study



PREPARED FOR:
CENTRAL MARIN SANITARY AGENCY
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Study Summary

The Central Marin Sanitation Agency has excess digester capacity that could accept more high strength organic wastes to produce more biogas and in turn generate additional renewable electricity on-site. This power could be used to offset current purchases of electricity from Marin Clean Energy (MCE) and excess power would be available for sale.

Additional deliveries of organic feed-stocks in the recent months have significantly increased biogas generation in the anaerobic digesters. CMSA's electrical cogeneration system currently powers the Agency's facilities for an average of 23 hours per day with biogas as its fuel source. CMSA expects there will be sufficient biogas generation in the near future to meet the facility's power demand and regularly export power for sale through the electrical grid. However, PG&E's Interconnection Agreement (IA) currently prohibits CMSA from supplying power to the grid.

In April 2016, CMSA retained MDB Consulting Engineers (MDB) to conduct the PG&E Interconnection Agreement Modification Project (Project). The project includes an analysis phase and then the modification of CMSA's IA based on the findings of the analysis phase. The purpose of this report is to summarize the analyses performed to determine the most beneficial arrangement for CMSA to reduce existing electricity cost and potentially generate additional revenue from the sale of the renewable energy not needed at the treatment facility. Presently, CMSA is unable to export excess electricity due to limitations of its interconnection agreement (IA) with PG&E. The findings of this analysis will provide the framework for CMSA to develop a new IA to allow it to fully utilize the existing cogeneration system capacity, potentially add additional generating capacity, and supply/sell the excess electricity.

MDB's scope of work includes preliminary engineering activities to define CMSA's excess digester capacity and the resulting maximum biogas production, maximum potential power generation based on full utilization of the digester capacity, options to supply excess generated power, and probable equipment upgrades that will be necessary to deliver power and have "islanding" capability, which allows for a seamless flow of power during a PG&E power outage. This preliminary work has been completed and the findings are summarized in this Executive Summary and discussed in detail in the attached Technical Memoranda.

The following is a summary of the preliminary engineering findings as it relates to each task in MDB's scope of work:

<u>Task 1 – Data Review and Kick-off Meeting</u> – CMSA provided plant information including single line electrical diagrams, cogeneration system documentation, biogas production data, PG&E energy usage, and the previous solar power study. At the kick-off meeting, the project

team toured the facility focusing on the PG&E equipment, electrical switchgear, and the cogeneration system.

Details of this activity are provided in the attached Technical Memorandum #1.

Task 2 – Evaluation of Existing Cogeneration System – The existing cogeneration system has a maximum capacity of 750 kW and the current average output is 625 kW. The current digester capacity utilization is just under 50 percent. In order to fully utilize the maximum cogeneration system capacity, the biogas production needs to increase by 17 percent by adding additional organic feedstocks such as fats, oils and grease (FOG) and food waste (FW). This will increase the digester capacity utilization to approximately 59 percent.

Task 3 – Evaluation of Opportunities to Maximize the Use of the Existing Digesters – Biogas production can be significantly increased by fully using the available digester capacity by accepting additional organic feedstocks deliveries. The additional biogas produced could support a second engine generator in the 600 to 950 kW range. The estimated cost for a 600 kW system is $6,000,000 and a 950 kW system is $8,000,000. These cost estimates include site electrical upgrades, but not expansion of the FOG/FW facility.

Details of Tasks 2 and 3 are provided in the attached Technical Memorandum #2/3.

Task 4 – Evaluation of Solar Power Opportunities – It is currently estimated that CMSA could install 200 kW of solar facilities. While there is less space available for solar facilities then was identified in the 2002 solar study, the efficiency improvements made to the solar technology since then offset this to a large degree.

Details of this activity are provided in the attached Technical Memorandum #4.

Task 5 – Assessment of the Existing Switchgear – The existing switchgear components do not require significant upgrades. However, it is estimated that $600,000 of communications improvements between CMSA and PG&E facilities are necessary to allow for power supply to the grid. The true facility upgrade requirements will be determined during the IA modification process since PG&E makes the final determination of the required infrastructure.

Details of this activity are provided in the attached Technical Memorandum #5.

Task 6 – Electrical System Islanding – Approximately $135,000 in electrical system upgrades are necessary to allow for “islanding”. The recommended improvements are the same for the existing cogeneration engine and if a second engine generator is installed in the future.

Details of this activity are provided in the attached Technical Memorandum #6.

Task 7 – Identification of Power Sales Options – Several power sale options have been identified. The most attractive options are PG&E’s E-BioMAT at $0.128/kWh and Marin Clean Energy’s (MCE) Feed-In Tariff program at $0.10/kWh. Other power sale options include net metering with PG&E or MCE and a power sale/supply agreement with MCE.

Details of this activity are provided in the attached Technical Memorandum #7.

Task 8 – Economic Comparison of the Alternatives – The Clean Water State Revolving Fund has a Green Project Reserve program that offers planning and design/construction funding with 50 percent of the capital cost "forgiven" and a 1.7 percent interest rate for a 20-year loan. There are other grant programs available through the California Energy Commission and CalRecycle. Assuming projects are funded through the Green Project Reserve, a 600 kW project would cover all of its costs over a 20-year period and return an estimated net income of $260,000 in Year 1. A 950 kW project would cover all of its costs and return an estimated net income of $520,000 in Year 1.

Details of this activity are provided in the attached Technical Memorandum #8.

Findings and Conclusions

The analysis considered two phases of power generation within the treatment facility. Phase I capacity is limited by the existing cogeneration engine output capacity. Phase II is limited by the available excess capacity of the digesters.

Phase I of the analysis focused on optimizing the output of the existing 750 kW generator by providing it the necessary biogas to run it close to 100 percent capacity. Presently the digester capacity utilization is just under 50 percent of the total capacity with the average output of the generator at 625 kW. To produce an average gross output of 735 kW, which accounts for minimal cogeneration system downtime, the digesters would need to produce 17 percent more biogas which increases digester capacity utilization to about 60 percent of their total capacity. In this scenario, CMSA would generate an excess 670,000 kWh annually of renewable electricity for sale and reduce its annual purchase of electricity from MCE to under 150,000 kWh.

Both PG&E and Marin Clean Energy (MCE) have relatively new programs to buy renewable power. Their programs offer limited time, attractive rates that are guaranteed over a 20-year period. The rates that are offered decrease over time and then disappear entirely when specified amounts of renewable power are secured. PG&E's Bioenergy Market Adjusting Tariff (E-BioMAT) is currently $0.128/kWh. MCE's local, renewable program is currently at $0.10/kWh and MCE is willing to work with CMSA to improve this standard offering. Selling CMSA's excess power from the existing generator operating at full load under PG&E's E-BioMAT Feed In Tariff (FIT) would result in net annual revenue of approximately $131,000. Utilizing the MCE FIT, the resulting net revenue is $112,000.

Another option is to Net Meter with PG&E or MCE wherein excess power is "banked" within the grid and extracted when facility power demand exceeds the cogeneration system capacity. Net Metering would result in a zeroed out electricity bill with the excess power being compensated at approximately $0.04/kWh. This results in approximately $81,000 in net revenue.

A third possibility is an arrangement where MCE buys all of the existing cogeneration system output (750kW) and in turn CMSA purchases all of its power from MCE. Based on standard rates and tariffs, this is not the most economic arrangement for CMSA. However, further discussions with MCE may make this arrangement comparable or even more attractive than the other power sale options.

A preliminary evaluation of CMSA's existing electrical system identified approximately $600,000 of potential improvements to supply power to the grid. These improvements provide communication between CMSA and a utility substation located approximately 15,000 feet from CMSA.

"Islanding" is a mode of operation where power flows seamlessly from the cogeneration system or back-up power generator in the event of a PG&E power failure. A preliminary evaluation of the cogeneration system determined that "islanding" is possible with approximately $135,000 in electrical improvements and when the plant power demand closely matches the cogeneration power output. The cogeneration system is not typically capable of handling a large, abrupt power swing. As a result, additional work is necessary to determine if the seamless flow can be maintained when a significant amount of power is being received from or supplied to the grid during a power failure.

Phase II assesses maximizing biogas production and construction of additional power generation capacity to utilize the resultant biogas. The existing digesters could accommodate an additional input of 15,000 pounds per day of volatile solids (VS) to maximize digester gas production. Assuming a 50/50 blend of food waste and fats, oils and grease (FOG), this equates to an additional 14 tons of food waste and 12,000 gal of FOG per day. The existing FOG/F2E station would most likely need to be expanded as the organic feedstock volumes would exceed the original design capacity of the facility. The capital cost to increase the capacity the FOG/F2E station is not included in this analysis because the system improvements are currently undefined.

The additional biogas produced from the increased digester loading would support a second generator in the 600 to 950 kW range. The 600 kW system would cost approximately $6 million, including switchgear upgrade costs. The 950 kW system would require a system to thicken the feedstock to approximately 5 percent solids prior to introduction to the digester. The estimated cost for a 950 kW system is $8 million, including switchgear upgrade costs, not including a feedstock thickening system.

Neither of the cost estimates includes capital improvement costs that PG&E may assess to resolve congestion problems in the grid created by accepting this new power supply. These costs will be determined by PG&E and included in the Interconnection Study that will prepare as part of the IA modification process. While these costs are unknown at this time, a pre-application study prepared by PG&E specifically for this project confirmed the adequacy of the nearest PG&E substation to accept both Phase I and Phase II power amounts and did not reveal any known congestion problems.

Several grant and low interest loan programs are available to reduce the capital cost of an interest rate for the facility upgrades. One of the most attractive is the Green Project Reserve program from the Clean Water State Revolving Fund that provides both planning and design/construction funds on a loan with "principle forgiveness" basis. For planning activities, such as feasibility analyses, energy marketing, CEQA and permits, the GPR can forgive 75 percent of the required budget up to a maximum of $500,000. For design and construction, 50 percent of the cost can be forgiven, up to $4 million. In either case, the remaining funds can be directly provided by the sponsoring agency or borrowed from CWSRF on a low interest, long-term basis. Current rates are a 1.7 percent, up to 30-year loan for the balance.

Other grant programs from the California Energy Commission and CalRecycle are also available. Both of these grant programs have funding reserved specifically for projects that generate electricity from biogas that uses food waste as a feedstock. It may be possible to combine grant funding from multiple programs to improve the project financing.

Assuming power sales at a rate comparable to PG&E's E-BioMAT, and financing through the Clean Water State Revolving Fund's Green Project Reserve Program without any additional grants (1.7 percent, 20-year loan with $4 million principle reduction), the 600 kW project would cover its costs and return an estimated $260,000 in Year 1 ($3.4 million on an NPV basis) over the 20-year analysis period. The 950 kW project would cover its costs and return an estimated $520,000 in Year 1 ($7.3 million on an NPV basis).

Assuming the necessary electrical improvements for "islanding" are made as part of Phase I, the Phase 2 system would not require any additional capital improvements for "islanding" the expanded system.

The analysis also reviewed the potential for solar power based on a prior study completed in 2002. Compared to the information in the study, CMSA has less available space for solar facilities and the efficiency of solar PV has improved. The approximate capacity of solar PV system is now 200 kW. Provided this solar power is used on-site and not sold, implementing solar at a later date would not affect the IA modification process. With similar projects in this size range and the rate currently offered by MCE, a 200 kW solar project could be economically attractive for CMSA.

Recommendations

Based on the findings of the analysis, the study recommends that CMSA follow the next steps:

1. Begin the Interconnection Agreement (IA) process with PG&E for the existing engine operating at full load plus up to a 950 kW new generator.
2. Consider including Islanding as part of the project description.
3. Apply for the a power purchase agreement (PPA) and/or net metering agreement with MCE to reserve the currently available high pricing and conduct further discussions with MCE to determine if their preferred "buy all/supply all" arrangement for Phase 1 and PPA pricing for Phase 2 can be made more attractive than a Phase 1-Net Metering and Phase 2-sale to PG&E under their higher priced Biomass power purchase program.

4. In parallel, apply for an E-BioMAT PPA with PG&E to get into the supplier queue and secure the highest payment level available, in case discussions with MCE don't work out.
5. Begin the renewable energy certification process with the California Energy Commission as it is required to net meter with MCE and PG&E as well as to sell renewable power to PG&E and MCE
6. Complete CEQA for the Phase 2 additional generator as this is required to obtain a PPA with either PG&E or MCE
7. Monitor grant and low interest funding opportunities and apply for attractive funding as appropriate.
8. Enter into a Power Purchase Agreement with MCE for the Phase 2 power provided they make it more attractive than PG&E's Bio-MAT FIT program.

These analyses are based on various preliminary assumptions as to the characterization and quantities of future deliveries of additional food waste and FOG. Because the projection of the types, quantities, and gas generation capabilities of these organic waste sources significantly affects the performance of the existing digesters and the project's economics, we also recommend that a more in-depth evaluation of this topic be performed in the next phase of work on this project.

Opinion of Probable Construction Costs

The cost estimates provided is this report are high level and preliminary.

The Team has no control over costs of labor, materials, competitive bidding environments and procedures, unidentified field conditions, financial and/or market conditions, or other factors likely to affect the probable cost of the construction of the facilities, all of which are in a state of change, in light of the high volatility of the market. The Opinion of Probable Construction Cost (OPCC) will be a "snapshot in time" and the reliability of this engineering opinion of probable construction cost will inherently degrade over time. The Team cannot and does not make any warranty, promise, guarantee, or representation, either express or implied, that proposals, bids, project construction costs, or cost of operation or maintenance will not vary substantially from its good faith OPCC.

CMSA acknowledges that the scope of the task is limited. This estimate will not relieve the engineer of record, or his employer, of any aspect of their responsibility for the design. In addition, this estimate will not guarantee or warrant the sufficiency of the design or project documents. CMSA acknowledges that the estimate will not encompass construction safety or environmental impacts.

This Agreement is intended for the sole benefit of the signatories to this Agreement and is binding on their respective successors and assigns. Nothing in this Agreement is intended or may be construed to give any person, firm, corporation or other entity, other than the signatories hereto, any legal or equitable right, cause of action, remedy or claim under this Agreement.

Purpose

Purpose of this technical memorandum is to summarize the activities that took place in April 2016 in support of the CMSA Interconnection Agreement Modification including the kick-off meeting, data request, and initial electrical system assessment.

Kick-Off Meeting

MDB Engineers Team completed the kick-off meeting on April 13th, 2016 with CMSA staff to discuss and finalize the scope of work as well as develop the schedule for completing it. The meeting was attended by Brian Thomas, Tuomas Groves, Kevin Lewis, and Kit Groves of CMSA as well as the MDB Team, which consisted of Michael Brown, Sarwan Wason, Steve Robinson, and Ryan Ramos. At the meeting, the group agreed to focus the study on enhancing the biogas production to determine the amount of additional electricity that could be produced by the co-generation system. The additional electricity production calculated in this study, which was initially estimated to be < 2 MW and will be updated in later Technical Memos, would be used as the basis for the Interconnection Agreement (IA) modification process. The group agreed that the IA modification would attempt to follow the PG&E "fast-track" process to limit the cost and duration of the effort. In addition, the study would evaluate the potential for islanding the plant to minimize disruptions during PG&E outages. The timeline for completing the report is seven weeks from receipt of all items from our data request.

Following the meeting, the group toured the CMSA facility including the electrical room, the co-generation building, and the fats, oils, and grease/organic material drop off station near the anaerobic digesters.

Data Request

At the Kick-off meeting, the MDB team provided CMSA a detailed request for information that included plant information and data such as single line diagrams, co-generation system, PG&E data, bio-gas production, food waste and FOG data, digester capacity, prior solar PV study, and electrical system information.

CMSA provided the requested information on April 28th, 2016 via CD to MWH Global during their site visit as well as an upload to a shared DropBox account. Relevant PG&E data was obtained through CMSA's PG&E online account.

Assessment of Electrical Facilities

On April 28th, MWH Global (Jeff Mohr and Joshua Dela Cruz) conducted an on-site assessment of CMSA's electrical facilities. They met with Brian Thomas and toured the site, focusing on the PG&E transformer, electrical switchgear and co-generation building. The findings of this site assessment will be used to support Technical Memorandums 5 and 6 regarding the electrical switchgear and system islanding.

Findings and Conclusions

The kick-off meeting, data request, and electrical facilities assessment lay the groundwork for remaining technical memos and provide direction for the overall study of the CMSA's potential for supplying power to the local utility grid.

Purpose

The purpose of this technical memorandum (TM) is to estimate future digester gas (DG) and power generation (kW) potential using the full capacity of the two existing digesters at the Central Marin Sanitation Agency (CMSA) Wastewater Treatment Plant (WWTP) from projected future increases in fat, oil and grease (FOG), liquid organic wastes and food wastes collection.

Existing Plant Operation and Data

CMSA WWTP has two digesters which are 80 feet in diameter and 26 feet side water depth providing a volume of 261,381 cf (cubic feet). In addition to sewage sludge, the digesters are also fed FOG, liquid organic wastes, and food wastes from businesses. Available 2015 operating data provided by CMSA was reviewed and the following findings are made based on one full year of data. Last 12 month of power information is based on the 3/23/2015 to 3/22/2016 data provided by CMSA. Current cogeneration (cogen) operation is based on controlling the cogen power output so that the power purchase from utility does not go down below 30 kW to avoid power export.

- Average sewage sludge fed to digesters = 14,682 # volatile suspended solids (VSS) /day.
- Average FOG/food waste fed to digesters = 2,576 # of VSS /day.
- Total VSS fed to digesters = 0.066 # VSS /cf of digester volume (using both digester in service).
- Hydraulic Retention Time (HRT) = 42.5 days.
- Average DG production in 2015 = 222,000 cfd.
- Average DG production in last 12 months = 233,000 cfd.
- Maximum DG production in 2015 = 260,000 cfd.
- Maximum DG production in 2016 = 310,000 cfd.
- Existing engine generator maximum capacity = 750 kW.
- Last 12 month power production = 14,892 kWh/day = 620 kW average.
- Last 12 month power purchased from Pacific Gas and Electric (PG&E) = 1,257 kWh/day = 52.4 kW average.
- Last 12 month total WWTP power usage = 16,149/kWh/day = 672.4 kW average.
- Last 12 month power production = 92.2% of total use (average basis).

Future DG Production Estimates

Digester overall loading in 2015 (including sewage sludge and FOG / food waste) was slightly below 0.06 # VSS/cf using both digesters in service. The 2015 digester VSS loading of 0.06 # VSS / cf can be easily doubled to 0.12 # VSS / cf in the future based on industry standards. HRT in 2015 was 42.5 days. By doubling the sludge feed at current concentrations the HRT will be reduced to 21 days which is still higher than the minimum 15 days HRT required. Therefore there is potential for increasing the feed to digesters and increasing the DG production by 100 percent from an average of 222,000 cfd to an average of 444,000 cfd and from a maximum of 260,000 cfd to 520,000 cfd by collecting and feeding additional FOG and food waste in future.

Digester production data for the first four months in 2016 shows higher DG production rates compared to 2015. This is based on higher FOG and food waste fed to the digesters. This data does not effect the overall future DG production because the future DG production calculations are based on prorating from current production and utilizing the full digester capacity.

Future Power Generation Estimates

Future power production can be increased in a similar proportion as increase in the DG production as follows:

Average power production in 2015 = 620 kW

Some of the DG was flared in 2015 during periods when DG production is more than the engine generator (EG) needs at the load it could run at. The load on the generator is limited to keep the production about 30 kW less than the overall power demand for the WWTP. The data on the amount of DG flared was not available. According to CMSA there were only five events in 2015 for less than 24 hours duration when DG was flared. Therefore for this study it is assumed that 0 percent DG was flared in 2015.

Future estimate of power production = 620 X 1.818 = 1,127 kW average based on same efficiency as of the existing engine generator. However newer engines are available with about 20 percent higher efficiency than the existing engine.

Assuming the WWTP keeps the existing engine and installs a newer higher efficiency engine generator, the size of the future engine generator could be calculated as follows:

1,127 - 750 = 377 X 1.20 = 452 kW (use a round number of 450 kW)

Therefore there is a potential for an additional engine generator with a design capacity of 450 kW in future with no change in current operation strategy of handling FOG/food waste and digestion. If existing engine generator is used for standby purpose only then the new generator size will be = 1,127 X 1.2 = 1,352 kW (Use a round number of 1,350 kW).

There is also a potential for increasing the digester loading to 0.15 # VSS/cf if the FOG is thickened from a current average concentration of 3.3 percent to say 5 or 6 percent. Please note that this is not possible with the current FOG/food waste facilities. Construction of additional facilities would be required to achieve this higher loading. The cost of these additional future facilities to achieve this higher concentration is not included in this study. This could potentially increase the DG production by another 25 percent (0.15 / 0.12 = 1.25) and therefore increase the power production as follows:

$$1{,}127 \times 1.25 = 1{,}409 \text{ kW}$$

$$1{,}409 - 750 = 659 \times 1.2 = 791 \text{ kW (use 800 kW)}$$

Total kW = 750 (existing generator) + 800 kW (new generator) = 1,550 kW total potential. If existing engine generator is used for standby purpose only then the new generator size will be = 1,409 X 1.2 = 1,691 kW (use a round number of 1,700 kW).

The cost benefit analysis and payback period of adding another generator depends on the capital costs, operation and maintenance costs and the price of electricity which can be obtained for the excess exported green energy.

Table 1 summarizes the estimated construction costs, current power production and power purchased from PG&E and estimated future power production and power sold to PG&E for various options.

Findings and Conclusions

1. 2015 data shows that the existing digesters were loaded to approximately 0.066 # VSS /cf of digester volume and HRT was 42.5 days. This level of VSS loading can be easily increased to 0.12 # VSS / cf in future resulting in 81.8 increase in DG production by using full capacity of both digesters if adequate quantity of FOG/food waste can be collected in future.
2. A second engine generator of approximately 450 kW size can be installed to utilize this additional future DG production. Most of this energy will be sold as green energy to make the WWTP self- sufficient and an energy exporter.
3. If the FOG/food waste is thickened to a higher concentration (say from current 3.3 percent to future 5 percent) the future DG production and power production can be increased by about 25 percent (0.15 /0.12 =1.25). This could increase the size of the new generator to about 700 kW.
4. Having a second generator will allow approximately 92 percent of WWTP power production even when one of the generator is down for maintenance, thereby eliminating or significantly decreasing the electrical demand charges from PG&E.
5. If the existing engine generator is used for standby purpose only then the new generator size will be larger because of higher efficiency (about 20 percent) of available newer engine generators. This will increase the size of the new engine generator to 1,300 kW with 0.12 # VSS /cf loading and 1,600 kW with 0.15 # VSS /cf

loading. This will also increase the overall kWh produced and kWh sold as presented in Table 1.

6. The cost benefit analysis and payback period of adding another generator depends on the capital costs, operation and maintenance costs and the price of electricity which can be obtained for the excess exported green energy.

Table 1 Power Generation Summary
Interconnection Agreement Modification
Central Marin Sanitation Agency

	Current Operation (2015)	Estimated Future Using 100% Digester Capacity			
		0.12 # VSS/CF Loading		0.15 #VSS/CF Loading(6)	
		Use Existing EG	Existing EG as Standby	Use Existing EG	Existing EG as Standby
EG kW Size	750	750+450	1,300	750 + 700	1,600
kWh Produced/Year(1)	5,435,580	9,460,800	10,249,200	11,445,900	12,614,400
Net kWh/Year(2)	5,435,580(3)	8,987,700	9,736,700	10,873,600	11,983,700
kWh Used/Year	5,894,385	6,000,000	6,000,000	6,000,000	6,000,000
kWh Sold/Year	(458,805)	2,987,700	3,736,700	4,873,600	5,983,700
Estimated Construction Cost(4)	NA	$3,339,000	$8,603,400	$4,821,700	$9,752,200
Estimated Annual O&M Cost(5)	$109,000	$189,200	$205,000	$228,900	$252,100

Notes:
(1) Assuming 95% availability or 5% downtime.
(2) After deducting 5% for parasitic losses.
(3) Parasitic loads are included in kWh used per year
(4) These costs includes digester gas condition system costs and installation, contractor's mark up and bonds but does not include costs for PG&E upgraded interconnection charges.
(5) Estimated annual operations and maintenance (O&M) cost are based on typical values of 1.5 cents/kWh for cogen and 0.5 cents/kWh for gas conditioning system.
(6) The additional costs for constructing future facilities needed to achieve this higher loading are beyond the scope of this study and are not included in this estimate.

Purpose

The purpose of this technical memorandum is to summarize and update the findings from the 2002 Solar Power Feasibility Study completed by Brown and Caldwell.

Solar Power Study

The Solar Power Feasibility Study completed by Brown and Caldwell evaluated the CMSA site for the technical and financial feasibility of installing solar PV at the site. This study also reviewed a 2001 BP Solar report provided as part of a proposal by BP Solar. The BP Solar report proposed 17 solar PV arrays with a capacity of 1,056 kW spread throughout the CMSA site. Brown and Caldwell focused on the most promising locations and reduced their recommended project to eight solar arrays (including three ground mounted systems, four roof top systems, and a parking canopy structure) with a total capacity of 248 kW. The report's system capacity calculations are based on two types of solar PV modules, a 160-watt crystalline silicon module and amorphous silicon (thin film type) laminate, that have since been surpassed in efficacy (power/area) allowing for systems with higher output on a similar or smaller footprint. The estimated cost of the 248 kW system was $2.27 million and the suggested implementation approach was design, bid, build or design-build with CMSA owning and operating the system.

Update to Study

Over the last 14 years since this study was completed, the available space for solar PV arrays on the CMSA site has been reduced, specifically two of the areas (sites A and B of Figure 4-1) designated for ground mounted systems can no longer support them since they have other dedicated uses. However, during the same timeframe, solar PV technology has improved dramatically with the efficiency of solar modules increasing by over 50 percent. In addition, the cost of solar in that timeframe has gone down three to four-fold and third-party financing of solar projects has become a standardized process with dozens of major integrators vying for projects. With these factors in mind, CMSA can still benefit from a solar PV system (even though it is smaller than previously assessed) as well as an implementation arrangement (a power purchase agreement - PPA) that would result in little or no upfront cost. Based on the available area described in the 2002 study and a review of aerial images, the maximum solar PV system size is now estimated to be 200kW. This estimate is limited to existing available information and a more in-depth analysis should take place prior to determining an appropriate system size.

Findings And Conclusions

It is recommended that CMSA explore incorporating solar PV as part of its on-site generating portfolio and study its implications with respect to the Interconnection Agreement modification. The recommended implementation approach is to enter a PPA with a developer that would design, build, own, and operate the system with CMSA buying the power. Next steps include evaluating the impacts of adding solar PV to the site including required electrical infrastructure upgrades (if any) and available compensation for generating solar power.

Provided that the solar power will be fed directly to CMSA's motor control centers on site, implementing this additional 200 kW of solar would not affect the interconnection requirements. This would enable the solar power to offset some of the power that would otherwise be derived from the cogeneration system, allowing more biogas generated power to be sold. If the solar power was to be sold, PG&E's Rule 21 has additional requirements and studies for solar generators exporting renewable power that would need to be addressed at the time the decision to implement solar was made.

Purpose

The purpose of this technical memo is to evaluate options associated with selling power generated from the digester gas system and a potential solar photovoltaic (PV) system at the Central Marin Sanitary Agency Facility (Facility) and provide recommendations for the modification of the existing electrical equipment. The Main Switchgear was evaluated based on the following proposed power generation scenarios, 1) maximize power generation from the existing cogeneration plant, 2) maximize power generation by expanding the existing co-generator facilities to utilize fuel at the possible maximum digester output (based on the findings in the preceding Technical Memoranda), and 3) adding 200 kW of solar PV to the above scenarios.

The assumption of this memo is the solar renewable power generation is to be a future addition with all solar power generation being consumed within the facility as a non-export renewable power source. PG&E Rule 21 has additional requirements and studies for solar generators exporting renewable power that this memo does not address. If the assumption does not hold, the impact on the cost of the interconnection system and potential downstream modifications required to PG&E's system is beyond the scope of this current assignment.

Existing Plant Conditions

The existing cogeneration system consists of a 750kW, 480V, 3-phase co-generator (utilizing digester gas generated on-site) and is paralleled with PG&E's 1500kVA transformer through the Main Switchgear. A 750kW diesel generator is available for backup. The cogenerator and diesel generator are located in the Solids Handling Building. The Main Switchgear and PG&E transformer are located at the Electrical Building.

Based on the findings in the Existing Plant Operation and Data section, the average power production from the cogenerator in 2015 was 620kW and power was purchased from PG&E at an average of 52.4kW. The average demand from the treatment plant was 672.4kW for 2015. CMSA's 750kW cogenerator has spare capacity to supply power to the grid based on the reported average demand. However, the existing Interconnection Agreement with PG&E does not permit power to be exported into their system

Recommendations

In order to supply power to PG&E, CMSA will need to apply for a new Interconnection Agreement. During the study, PG&E would determine if the generator system requires modifications and if further supplemental review could be required. The cost of these modifications will be determined after the study has been completed. The study will involve checking the existing protective relays and related settings and to see if they meet the Rule

21 requirements for power exportation. The intent of the studies is to ensure the safety and reliability of the utility's distribution system.

A PG&E Pre-Application Report has provided information on the capacities of their system to the substation from the Facility. The initial assessment is to upgrade the 1500kVA transformer and provide a SCADA Recloser. The assessment is based on a future power generation option of 1900kW. The first phase is to supply power with the existing power generation of 750kW. PG&E will update their assessment based on the first phase power generation.

Rule 21 and Interconnection Handbook requirements include a main disconnect at the utility meter that is lockable in the open position. The existing Main Switchgear meets this requirement. Note that the existing co-generator protection includes redundant GE Multilin SR489 protective relays. Redundant relays are a requirement of Rule 21. The GE Multilin SR489 relay is a PG&E approved multifunction relay, and it was required to be tested for the Cogeneration Engine Replacement Project according to PG&E's Detailed Interconnection Study Final Report conducted in 2003. As such, it is expected that the existing relay could be reused under the new Interconnection Agreement with PG&E. PG&E may require redundant multifunction relays on the utility main breaker.

A direct transfer trip may also be required by PG&E under the new Interconnection Agreement. During a fault in the PG&E distribution system, a PG&E direct transfer trip signal will be sent to the Main Switchgear to initiate the opening of the CMSA utility main breaker. This will prevent the generator system from feeding into a fault condition on the utility side of the service. CMSA currently has a recloser sequence in place. PG&E would determine that a SCADA equipped recloser may be required. When the utility power is restored and before the recloser closes, the stability of the utility voltage and frequency will be checked for a period of time. When the utility's system is verified to be stable, the utility main breaker will close. The Main Switchgear will communicate to PG&E that the utility main breaker has closed. This will prevent the generator system from tripping due to an under-frequency condition. The communication between the substation or recloser and the utility main breaker can be by wire or wireless. Further investigation will be required to determine a proper method of communication which can depend on topology and distance.

Rule 21 states that the paralleling device (the CMSA utility main breaker in this case) is required to be able to withstand 220 percent of the interconnection facility rated voltage. The existing paralleling device has been in use in the current agreement with PG&E, but it is recommended to confirm with PG&E to verify if the device is acceptable.

In order to export power to PG&E and net meter, Rule 21 requires that a bi-directional meter be provided. The existing PG&E meter may not be bi-directional since the current agreement is a non-export agreement.

Additional modifications to the existing system will need to be made including modifying the control settings at the generator control system to limit the output power to match the utility transformer size. Also, the reverse power relay on the utility main breaker will need to be removed or new settings implemented to allow exporting power to the utility.

The Main Switchgear has adequate current-carrying capacity for the average demand as well as the peak demand. The peak demand of 868kW was recorded in January 2015, and PG&E provides power to the facility whenever the plant demand exceeds the 750kW cogenerator's capacity. The peak demand will require approximately 1300 amps at 0.8 power factor (PF) at 480 volts which is well within the Main Switchgear bus rating of 3000A.

Future Power Generation

Based on the findings in the Existing Plant Operation and Data section, the digester gas production is estimated to be capable of producing up to 2050kW of co-generation power. Options available to CMSA for increasing co-generated power capacity with the intent to export/sell power include:

1. Use the existing 750kW cogenerator in parallel with a new 750kW cogenerator (1500 kW total co-gen power capacity)
2. Add a new 1650kW cogenerator and use the existing 750kW as standby (1650 kW total co-gen power capacity)
3. Use the existing 750kW in parallel with a new 1150kW cogenerator (1900 kW total co-gen power capacity)
4. Add a new 2050kW cogenerator and use the existing 750kW as standby (2050 kW total co-gen power capacity)
5. Add 200 kW of solar PV generation to the above scenarios to be evaluated in the future with interconnection agreement modified at that time.
6. For the 2050kW cogenerator unit, an option that is not explored in this technical memorandum is to tie the cogenerator on the utility's primary side. The existing Main Switchgear will not need to be replaced with a larger unit. A new service with PG&E would be required.

With an average WWTP power demand of 672.4kW, CMSA will be able to export up to 1377.6kW of power to PG&E. Solar generation would increase that by a maximum of 200 kW or the maximum Utility transformer rating, whichever limit is hit first.

Recommendations

The Rule 21 and Interconnection Handbook requirements in the Existing Plant Conditions apply to the future power generation systems. In addition, the cogeneration system will require modifications due to the electrical load upsizing.

1. The existing cogenerator set will require relay setting adjustments, and the reverse power relay will need to be removed or new settings implemented to allow exporting of power.

2. Additional redundant protective relays for the new cogenerator and the utility main breaker will be needed to meet PG&E's Rule 21 and Interconnection Handbook.
3. A new Interconnection Detailed Study by PG&E may need to be performed depending on the outcome of the various screens listed under PG&E Rule 21. The study and task costs will be determined after negotiations with PG&E.
4. For the 2050kW cogeneration system option, the Main Switchgear would require a replacement as the running amps would be above the switchgear bus rating of 3000A. In addition, the utility main, generator main and tie breakers will require upsizing. The Main Switchgear main and tie breakers will be sized accordingly for the 2050 kW system. Table 1 shows the possible transformer and circuit breaker size upgrades and the export power values. The existing Main Switchgear tie breaker is rated for 1600A, less than the 2000A utility and generator main breakers. The assumption is at least 400A is consumed from the electrical load on either side of the switchgear. This assumption is carried over to sizing the tie breaker for the 2050kW system.
5. With a larger cogenerator unit, a larger fault current can travel through the Main Switchgear bus. The Main Switchgear bus bracing rating is 100,000 amps. For the largest option, a 2050kW cogenerator, a simplified short circuit calculation during a fault on the Main Switchgear bus assumes that the subtransient reactance is the same value as the existing 750 kW unit at 0.1262[1]. The cogenerator short circuit contribution will be 24,423 amps. A 2000 kVA utility transformer will be needed as shown on Table 1. The transformer fault contribution will be 41,837 amps. Lastly, assuming the 672.4 kW average demand load on the Main Switchgear is all motor loads for simplification, the load short circuit contribution will be 4,044 amps. The total short circuit fault through the Main Switchgear bus will be 70,304 amps. This is within the 100,000 amps bus bracing limit. The smaller power generation options will have lower fault contributions as the cogenerator and transformer sizes will be smaller. The Main Switchgear has adequate bus bracing capacity for the future power generation options.
    a. The utility main breaker, tie breaker and generator breaker each have interrupting ratings of 100,000 amps. These breakers have adequate capacity for the future power generation options.

[1] "Short Circuit, Overcurrent Protection Device Coordination and Arc Flash Study prepared by Banaban Diversified Services LLC on July 2012.

Table 1: Required Upgrades Summary

	Future Power Generation Options and Required Upgrades			
	Use Existing EG	Existing EG as Standby	Use Existing EG	Existing EG as Standby
New EG kW Size	750	1650	1150	2050
System Amps on Main Switchgear (Assuming 0.8PF)	2255.3	1984.7	2480.9	3082.3
Export Power (New System, kW – demand)	827.6	977.6	1227.6	1377.6
Export Power in kVA (Assuming 0.8PF)	1034.5	1222	1534.6	1722
Utility Transformer Size kVA Size	N/A	N/A	N/A	2000
Utility Main Breaker (Amps)	N/A	N/A	N/A	3000
Generator Main Breaker (Amps)	N/A	N/A	N/A	4000
Tie Breaker (Amps)	N/A	N/A	N/A	3000
Bi-directional Meter	Required	Required	Required	Required
Communication between Recloser and Main Switchgear Utility Main Breaker	TBD	TBD	TBD	TBD
Communication between Substation and Main Switchgear Utility Main Breaker for Direct Transfer Tripping	TBD	TBD	TBD	TBD

Communication

Rule 21 may require communications between the utility and the Facility. A direct transfer trip sent from the utility substation to the Main Switchgear will initiate opening the utility main breaker. PG&E would determine if a SCADA equipped recloser is required. When the utility power is restored and before the recloser closes, the stability of the utility voltage and frequency will be checked for a period of time. When the utility's system is verified to be stable, the utility main breaker will close. The Main Switchgear will communicate to PG&E that the utility main breaker has closed. The communication between the substation and the utility main breaker can be by wire or wireless. Further investigation will be required to determine an acceptable option.

Summary

The existing cogeneration system is capable of supplying power to the PG&E grid based on current average demand. The Main Switchgear currently has capacity to support the daily and peak demands of the treatment plant, and export the excess power during average demands.

The Main Switchgear has capacity to accommodate 3 of the 4 future cogeneration upgrade options. The 2050kW option requires replacement of the Main Switchgear as the system amps will be above the switchgear bus rating. The 2050kW system also runs the risk of overloading the 1500kVA PG&E transformer and a larger transformer will be needed.

Other modification costs to the generation system and Utility may be required depending on the assessment of PG&E. Table 2 summarizes the main electrical requirement cost estimates.

Table 2: Exporting Upgrade Cost Summary

	Existing Generation Summary Cost	Future Power Generation Summary Costs			
	Use Existing EG	Use Existing EG	Existing EG as Standby	Use Existing EG	Existing EG as Standby
kW Size		750	1650	1150	2050
Reverse Power Relay Removal or Settings Modification	$250	$250	$250	$250	$250
Transformer (2000 kVA)	N/A	N/A	N/A	N/A	$159,250
Utility Main Breaker	N/A	N/A	N/A	N/A	$40,000
Generator Main Breaker	N/A	N/A	N/A	N/A	62,650
Tie Breaker	N/A	N/A	N/A	N/A	$40,000
Main Switchgear (4000A Bus)	N/A	N/A	N/A	N/A	$2,100,000
Redundant Protective Relays	N/A	$310,000	$310,000	$310,000	$310,000
Communication between Recloser and Main Switchgear Utility Main Breaker	$260,000	$260,000	$260,000	$260,000	$260,000
Communication between Substation and Main Switchgear Utility Main Breaker for Direct Transfer Tripping	$260,000	$260,000	$260,000	$260,000	$260,000
Other Interconnection Study Modifications	TBD	TBD	TBD	TBD	TBD
Bi-directional Meter	$2,625	$2,625	$2,625	$2,625	$2,625
Labor and Equipment for Install/ Commission	$70,500	$97,000	$124,000	$108,000	$327,500
Total	**$593,375**	**$929,875**	**$956,875**	**$940,875**	**$3,562,275**

Note: Cogeneration system not included

Purpose

The purpose of this technical memorandum is to examine operation of CMSA co-generation Facility in an “island mode” by utilizing the cogeneration plant and/or the standby diesel generator disconnected from the utility power source in the event of a PG&E power failure.

Existing Power Generation Islanding Scenarios

There are different islanding scenarios for the existing generation system during a PG&E power failure. These include:

1. The cogenerator is running in parallel with PG&E and PG&E has a power failure.
    a. A coordination study is recommended to allow Islanding of the Facility. During a fault with the PG&E distribution system, the cogenerator and diesel generator can handle a fault for a short duration. The Main Switchgear’s utility main breaker relays will need to detect and clear the fault and open the breaker before the tie and generation main breaker can open. New relays and circuit breakers may need to be provided depending on the coordination study.
    b. The demand of the Facility occasionally goes above the cogenerators rating of 750kW. The utility may have a power failure during these times. The load shedding scheme does not load shed fast enough before the cogenerator shuts down due to overloading. There are options to prevent the cogenerator from shutting down:
        i. The standy diesel generator can start when the Facility demand approaches approximately 90 percent (675 kW) of the cogenerator rating. This allows the standby generator to supply power during peak demands and keeps the generation system running during a power failure.
        ii. During the coordination study, the tie breaker can be set to open at the same time as the utility main breaker to shed load and keep the cogenerator running. A good portion of the Facility will shut down and require starting up.
2. The cogenerator is not running and there is a PG&E power failure.
    a. The generation system needs time to start up and all power to the Facility will be lost. An existing load stepping scheme is in place and it prevents the generation system from overloading if too much load is started simultaneously. The diesel standby generator starts first and acts as a swing

bus and the cogenerator starts next. The purpose of a swing bus is to accommodate large power changes (additional and removal) to the system to result in steady power on the bus. The voltage/frequency and trip time settings of the relays due to Rule 21 and Interconnection Handbook may be stringent and require the diesel generator to act as a swing bus. Gas generators do not act as quickly to step load changes compared to similarly sized diesel engine generators. When a generator is running in parallel with the utility, the utility distribution system acts as a robust swing bus and allows the generator frequency and voltage dips to be at a minimum and stabilize quickly. When the generation system is islanding, the utility is not available to act as a swing bus and larger voltage/frequency swings can be expected.

The coordination study should also be performed when there is a fault within the Facility. Breakers local to the fault will be coordinated to prevent the fault from opening the generator main breaker and tie breaker.

Recommendations

Since the existing cogeneration system has adequate capacity to provide power for average demand of the treatment plant, the first case described in the above Existing Power Islanding Scenarios section is the most seamless option to keep the treatment plant running. The standby diesel generator will start to run when demand starts to rise to supply power during peak demands and no major interruptions to the operation are expected to occur. The second case has the risk of losing all electrical loads and causing a downtime at the Facility, until the generators can be brought on line and CMSA staff restarts the plant. Note that the standby generator status may change from emergency to non-emergency. The air system may require some additional after treatment of the exhaust system for the diesel and gas generators based on the interpretation of the Bay Area Management District. Re-permitting may be required for the generators.

Communications

CMSA currently has a recloser sequence in place. PG&E may determine that a SCADA controlled recloser may be required. When the utility power is restored and before the recloser closes, the stability of the utility voltage and frequency will be checked for a period of time. When the utility's system is verified to be stable, the utility main breaker will close. The Main Switchgear will communicate to PG&E that the utility main breaker has closed and the systems can run in parallel again. The signal to the recloser also prevents exporting power in the case where a non-export agreement is in place.

Future Power Generation

The future cogeneration systems being considered each will have adequate capacity to provide power for the average demand of the treatment plant as well as the peak demand of 868kW and island the Facility (assuming the plant demand remains approximately the same in the future).

Recommendations

A coordination study is recommended to allow Islanding of the Facility for all future power generation options. The Main Switchgear's utility main breaker relays will need to detect and clear a utility fault and open the breaker before the tie and generation main breaker can open. New relays and circuit breakers may need to be provided depending on the coordination study. Adding a new 750kW cogenerator with the existing 750kW cogeneration will have the same scenarios as in the Existing Plant Conditions section. If this alternative is selected, it is recommended that the new cogenerator be operated in parallel with PG&E and retain the existing cogenerator as a backup unit as demand loads start to increase.

For the larger cogeneration system alternatives from 1650 to 2050kW, the systems will be capable of handling the treatment plant's peak demands without the use of load shedding during a PG&E power failure. In the event that the power generation system is not exporting power, gas generators typically are not recommended to run below 30 percent of its rated power. The generator's durability will be reduced. The current Facility average demand is at about 41 percent for a 1650kW cogenerator, 58 percent for an 1150kW cogenerator and 33 percent for a 2050kW cogenerator. In the case for the 2050kW unit, the existing 750kW cogenerator can be used during these times to prevent underloading the 2050kW cogenerator. A load shedding scheme can be implemented at a future time in the event that plant electrical power demand grows beyond the cogeneration system's power production capacity.

As previously stated, PG&E's Detailed Interconnection Study Final Report was conducted in 2003 and it demonstrated that the cogeneration system was acceptable according to Rule 21 and the PG&E Interconnection Handbook. A non-exporting interconnection agreement with PG&E was finalized in September 2004. The existing generation control equipment is over 10 years old and with a new cogenerator addition to the system, a new generator control system would be required. A new PG&E interconnection study will be required for any new, larger cogenerators to meet Rule 21 and the Interconnection requirements.

Similar to the existing plant conditions, the diesel generator may need to act as a swing bus to successfully accommodate voltage and frequency swings without shutdown and further study will be needed to determine if this will be required and an acceptable option.

Additional modifications to the existing system will be required to modify the control settings at the generator control system to limit the output power to match the utility transformer size. Also, the reverse power relay on the utility main breaker will need to be removed or settings adjusted to allow exporting power to the utility or the relay setting may need adjustment if a non-exporting agreement is made.

As the case with the existing power generation system, the standby generator status may change from emergency to non-emergency. The air system may require some additional after treatment of the exhaust system for the diesel and gas generators based on the interpretation of the Bay Area Management District. Re-permitting may be required for the generators.

Communications

Similar to the existing system, PG&E may determine that a SCADA controlled recloser may be required.

Summary

The existing cogenerator is capable of powering the treatment plant during a PG&E power failure and the standby diesel generator can be used as Facility demand rises.

For future cogeneration power production, each system proposed has the minimum capacity to accommodate the average and peak demands of the treatment plant.

The cogeneration system will require the following items to Island the Facility.

1. Communication is required between the utility recloser and the Main Switchgear to ensure a safe and reliable distribution system.
2. In both the existing and future power production options, a coordination study is recommended to ensure the utility main breaker opens before the generation system and tie breakers.

See Table 1 for the estimated costs to upgrade for five islanding options to the treatment plant co-generation system. Please see Table 1 in Technical Memorandum 5 for additional costs. The Main Switchgear is recommended to be upgraded when the power production of the cogeneration system exceeds 2000kW.

Table 1: Islanding Upgrade Cost Summary

	Existing Generation Summary Cost	Future Power Generation Summary Costs			
	Use Existing EG	Use Existing EG	Existing EG as Standby	Use Existing EG	Existing EG as Standby
EG kW Size	750	750+750	1650	750+1150	2050
Coordination Study	$61,250	$61,250	$61,250	$61,250	$61,250
Utility Main Breaker and Protective Relays	$21,000	$21,000	$26,250	$21,000	$30,625
Generator Main Breaker and Protective Relays (Amps)	$26,250	$26,250	$30,625	$26,250	$35,000
Tie Breaker and Protective Relays (Amps)	$17,500	$17,500	$26,250	$17,500	$30,625
Labor and Equipment for Install/Commission	$5,500	$5,500	$7,125	$5,500	$8,250
Total	**$131,500**	**$131,500**	**$151,500**	**$131,500**	**$165,750**

Purpose

The purpose of this technical memorandum is to identify alternatives to sell excess renewable power generated at the CMSA WWTP. This memorandum covers available options including sales to Marin Clean Energy (MCE), PG&E, using the RES-BCT Program to offset energy use at CMSA Member Agencies, and direct sales to nearby entities.

Marin Clean Energy

Marin Clean Energy (MCE) is a community choice aggregation (CCA) program that provides electric power to Marin County and surrounding communities. As a CCA provider, MCE serves as an alternative to the local investor owned utility (IOU) and offers higher renewable content electricity to its customers at comparable rates. Since one of the goals of the CCA is providing locally generated renewable power, MCE is procuring up to 15 MW of local, renewable energy through a feed-in-tariff (FIT) for distributed renewable generation up to 1 MW per metered project. Under this FIT, MCE pays generators a price per MWh generated based on the source and delivery characteristics of the power and the amount of renewable power MCE has already contracted for. This is a very attractive pricing schedule, significantly higher than its typical wholesale power purchasing.

Presently, MCE is purchasing renewable power under what they call Condition 3 wherein they have purchased at least 4 MW and no more than 6 MW. At this level, MCE pays a twenty-year levelized price of $0.115/kWh for peak energy (e.g. solar) and $0.10/kWh for baseload (e.g. bio-gas fueled) fixed over a 20-year term. The baseload rate applicable to the biogas project is scheduled to reduce to $0.095/kWh when MCE reaches Condition 4 (6 to 8 MW under contract) and remains at this price until the full 15 MW program goal has been reached. The solar rate reduces by $0.005 per kWh each time MCE procured another 2 MW of renewable power up to the full 15 MW program limit.

If more than two percent of the power generated by the biogas system was produced from natural gas, it would have to be sold to MCE as “brown” power. Current pricing for “brown” power is approximately $0.037/kWh.

Based on a meeting between MDB Engineers and MCE representatives, an early phase option discussed is for MCE to buy all the power generated from CMSA’s fully utilized, existing co-gen facility (750 kW, both “brown” and “green” power) and have CMSA buy back the necessary power (at a lower rate) to satisfy its needs. The power generated from natural gas and biogas will have to be separately measured and will be compensated based on their respective FIT rates. This arrangement would allow CMSA to generate revenue from the sale of the electricity and buy power at a lower rate than the sale price. MCE is able to do this as they purchase power for resale from a variety of sources with varying prices. The CMSA project benefits because this FIT purchase program has a special pricing program that is higher than their other sources as it is a limited program designed to encourage small renewable energy project development within the communities MCE serves.

MCE staff mentioned that additional payment could be made, perhaps in the $2,000 to $4,000/month range if MCE was granted some level of rights to control the timing and amounts of renewable power delivery, This option is definitely worth exploring, if MCE is selected as the preferred power purchaser.

The FIT application process is relatively simple. The application requires:

1. Summary of results from the PG&E interconnection pre-planning meeting;
2. Signed Feed-In Tariff Application;
3. Evidence of site control (Lease, direct ownership or other);
4. Financial statements for project participants (developer and financier, in particular);
5. PG&E Generating Facility Interconnection Application and PG&E notice of complete application;
6. Copy of application for Renewable Portfolio Standard (RPS)certification from the California Energy Commission) and assigned pre-certification number, if available;
7. Evidence of environmental compliance review/notice of determination receipt.

For the initial project involving maximizing the utilization of the existing engine, the MCE application can be submitted as soon as the Interconnection Agreement application with PG&E is submitted and the PG&E preplanning meeting held. In addition, an application for California Energy Commission (CEC) RPS certification would also need to be submitted.

Additional on-site distributed renewable generation including enhanced co-generation and solar PV would also be eligible for the distributed renewable generation FIT. Each generation type (peak, baseload, intermittent) can provide up to 1MW of capacity with separate metering required. Each generation system requires separate applications and would need completed CEQA assessment as well prior to submitting the application.

MCE also can enter into Power Purchase Agreements (PPA) for amounts of power greater than 1 MW per metered project, through bilateral negotiations. According to MCE staff, this would likely result in a significantly lower price, perhaps in the $0.065/kWh range. Accordingly, it would be advantageous to CMSA to utilize the FIT program, if MCE is the preferred power off-taker.

PG&E

Pacific Gas and Electric (PG&E) is the local IOU and it provides transmission and distribution service for all customers in Marin County as well as electricity to those customers that opt out of the MCE CCA program. PG&E offers two FIT programs available for small renewable generators, the Renewable Energy Market Adjusting Tariff (E-ReMAT) and the Bioenergy Market Adjusting Tariff E-BioMAT. E-ReMAT is open to eligible renewable resources (e.g. solar, wind, small hydro) sized up to 3 MW. E-BioMAT is open to electricity generated from bio-gas sources such as wastewater treatment plants, dairy and agricultural wastes, and forest management byproducts. Both programs have contract prices (that are fixed over the term of the agreement) for the electricity that adjusts based on market acceptance and market depth and offer PPA terms over 10, 15 and 20 years. Procurement windows are offered every two months ("Program Period") in which eligible projects, placed in a queue based on the application submittal date, are offered to accept the contract price and sign a PPA. The contract price adjusts based on the subscription rate with downward adjustments applied to technologies that are over-subscribed and upward adjustments applied in cases of under-subscription. Projects that are not offered contracts or have declined the contract price remain in the queue until the next Program Period.

Solar electricity generated at CMSA would fall under the E-ReMAT FIT which presently pays a current contract price of $0.06123/kWh for the "as-available peaking" product (contract price at the start of the program was $0.08923/kWh). The relatively low price for solar electricity indicates the high number of projects applying for E-ReMAT FIT .

Electricity from the co-generation system would be compensated through the E-BioMAT FIT which presently pays a contract price $0.12772/kWh. The E-BioMAT FIT began accepting offers as of February 1, 2016. Since the program has only recently started the contract prices have not changed. The E-ReMAT and E-BioMAT FIT have similar application processes. The application requires:

1. The applicant shall have completed one of the following: passed Fast Track screens, passed Supplemental Review, completed a System Impact Study in the Independent Study Process, completed a Distribution Group Study Phase 1 Interconnection Study in the Distribution Group Study Process, or completed a Phase 1 Study in the Cluster Study Process for its Project (Interconnection Study);
2. Evidence of site control (Lease, direct ownership or other);
3. Attestation that developer has experience with generating technology
4. Submit a program participation request (PPR) form as well as provide supporting documents including a table of components, facility layout drawing, site map drawing, single line diagram, fuel resource attestation, and forecast and use of thermal output.

The project enrolling in the E-ReMAT or E-BioMAT FIT must be the only exporting project being developed, owned, or controlled by the Applicant on any single or contiguous pieces of property. This limits CMSA's flexibility with respect to developing additional on-site generation dedicated to exporting power including additional bio-gas fuel generation. This requirement also potentially impacts CMSA's ability to contract with MCE or other off-takers. In addition, facilities 500 kW and over must be a California Independent System Operator (CAISO) market participant including the following requirements: obtain an CAISO meter, participating generator agreement (PGA), and meter service agreement (MSA); and be in compliance with the CAISO Tariff. This requirement places additional costs on the project, which may impact its cost-effectiveness.

RES-BCT Program

Local government agencies benefit from an additional program available from the California IOUs that in essence extends net metering to cover electricity consumption at other agency-owned sites. The Renewable Energy Self Generation – Bill Credit Transfer (RES-BCT) Program allows excess renewable power produced at the generating facility site (generating account) to be used to offset utility bills at other sites owned by the same agency (benefitting account). Presently, joint powers authority (JPA) entities such as CMSA are not eligible to participate in RES-BCT although there are efforts underway to change the legislation to allow JPAs to participate. If this goes through, the bill credit could be shared with any or all of CMSA's member agencies up to a total of 50 individual PG&E meters.

In spite of this prohibition, there may be a somewhat complex way for CMSA to benefit from RES-BCT. This involves setting up an arrangement with an appropriate local government agency that both has sufficient load to absorb the power not needed by the plant and has some level of land-use authority over the project site. In this type of arrangement, CMSA leases the property or otherwise grants controlling rights to a qualifying agency in order for that agency to establish electric service and enroll in RES-BCT.

Since the plant is within the jurisdiction of the City of San Rafael, this would be the appropriate agency to lease to and provide the bill credit advantage. Another possibility might be one of the local sanitation districts Member Agencies if their territory covers the CMSA plant site. Within this arrangement, CMSA and Agency partner would set up a power purchase agreement (PPA) in which CMSA would sell the power to the agency (at a cost lower than the corresponding PG&E bill rate) and the Agency would receive bill credits for the electricity purchased. The bill credits are valued at the time-of-use, generation-only portion of the electric bill. If the generating account is placed on the A6 rate schedule, the bill credit could be worth on average $0.11/kWh for baseload generation (cogeneration) and $0.16/kWh for solar. However, PG&E has placed greater scrutiny on A6 accounts and may move to limit this existing "loophole."

Direct Sales to End Users

End users in Marin County looking to procure renewable energy may serve as an off-taker for CMSA generated renewable power. Entities such as Marin Sanitary Services (MSS), located just west of CMSA, and San Quentin State Prison may serve as partners for CMSA's excess renewable power. MSS has an annual electricity usage of 800,000 kWh, average weekday demand of 120 kW (peak demand of 430 kW), and a relatively uneven load profile (peak demand occurs in the early morning between 3am and 6 am and in the evening between 5pm and 11pm). Their load profile does not match well with the generation profile of CMSA cogeneration or potential solar PV output. However, energy supply profiles can be shaped to accommodate the necessary demand profile of a given customer.

Setting up direct sale of electricity requires following PG&E's Direct Access (DA) program. Under DA, CMSA or its agent will have to register as an electric service provider (ESP) and as an ESP, CMSA could sell power directly to any interested party in the PG&E service area. The party interested in purchasing energy from an ESP would then enroll in DA through a highly competitive lottery process in which entrants are provided a random numerical position on a wait list. Entries are typically submitted six months in advance of the next DA service cycle. Since DA service has reached its load cap, those on the wait list will be granted DA service only if an existing DA customer exits the program freeing up a slot for a new DA customer.

The value of CMSA electricity to local end users is determined by the other electricity options available. PG&E and MCE both provide electric service in the area with PG&E providing power at $0.095/kWh and MCE offering power at $0.076/kWh. In order to attract a buyer for their excess power, CMSA would have to sell power at or below the PG&E and MCE rates. Moreover, the PG&E's DA program is currently over-subscribed and is not presently accepting new participants. Given these two limitations, direct sales produce significantly lower revenues to CMSA then the MCE, PG&E and RES-BCT options.

Findings and Conclusions

1. CME's offer to purchase all the electricity generated by the co-gen system and then selling it back to CMSA, perhaps coupled with additional payment for dispatchability, may provide the CMSA the best value depending on the most cost effective configuration of the expanded biogas system (one large (>1 MW) engine with the existing engine as standby vs. adding a second engine and running it in parallel with the existing engine), and final purchase and selling terms.
2. PG&E offers the highest FIT for electricity from the co-generation system through its E-BioMAT Program at $0.12772/kWh.
3. RES-BCT might provide a methodology for beneficial use of the power. Since CMSA has no off-site meters, the available users would be limited to the City of San Rafael and possibly one if the Sanitation District Member Agencies if they have some level of land-use authority over the project site. Unless the current prohibition of JPA eligibility is lifted, this method would require the most involved process which includes a complicated leasing arrangement with an appropriate and interested agency and an uncertain future value. Accordingly, this methodology is not recommended at this time.
4. Direct Access sales to nearby agencies is the most challenging arrangement since the DA program is capped at its maximum enrollment and there is a waiting list of customers attempting to enroll. Further, since it would be offsetting lower cost power currently purchased by the users ($0.076 to $0.095/kWh) which would likely need to

be further discounted to convince the user to purchase the power, the Direct Access sales option would produce significantly lower revenues to CMSA then the MCE, PG&E and RES-BCT options. Accordingly, we do not recommend any further investigation of this option.

5. The comparison of these two remaining power sales options (MCE and PG&E) will be included in the economic analysis technical memorandum and a final recommendation will be provided in the final report.

Purpose

The purpose of this technical memorandum is to utilize the cost and revenue estimates developed in the previous Technical Memoranda to present a preliminary level, lifecycle cost comparison of the electric power generation options.

Assumptions

The economic analysis uses a cash flow model to determine the net present value (NPV) or net present cost of the selected electric power options. The following table shows cost and power generator assumptions that are utilized in the cash flow analysis.

	Current Operation (2015)	Optimized Existing Engine	Use Existing Engine Plus New Engine	Use Existing Engine Plus New Engine	New Engine (Existing as Standby)
Generator Size (kW)	750	750	750+600	750+950	1,500
kWh Produced/Year	5,435,580	6,440,000	10,643,400 (1)	13,261,400 (1)	11,826,000 (1)
Net KWh/Year (2)	5,435,580 (3)	6,440,000 (3)	10,111,200	12,582,800	11,234,700
kWh Used/Year	5,894,385	5,894,385	6,000,000	6,000,000	6,000,000
kWh Sold/Year	-458,805	531,000 (4)	4,111,200	6,582,800	5,234,700
Estimated Construction Cost (4)	NA	N/A	$ 4,452,000	$ 6,406,000	$ 9,927,000
Electrical System Upgrade Costs (for export scenarios)	$ -	$ 593,125	$ 1,166,025	$ 1,310,175	$ 1,439,375
Estimated Annual O&M Cost (5)	$ 109,000	$ 128,800	$ 213,300	$ 265,300	$ 236,400

(1) -- Assuming 95 % availability or 5 % downtime.
(2) -- After deducting 5 % for parasitic losses
(3) -- Parasitic loads are included in KWh used per year
(4) -- Net sales (includes selling during excess generation and buying when demand > supply.
(5) -- These costs includes digester gas condition system costs and installation, contractor's mark up and bonds but does not include costs for PG&E upgraded interconnection charges
(6) -- Estimated annual O& M cost are based on 1.5 Cents/KWh for cogen and 0.5 Cents/KWh for gas conditioning system

Other assumptions include:

- Analysis period: 20 years;
- Discount rate: 2.5 percent;
- Clean Water State Revolving Fund (CWSRF) interest rate: 1.7 percent;
- CWSRF Green Fund Reserve loan forgiveness: 50 percent of project cost to a maximum $4 million;
- O&M annual escalation rate: 2 percent;
- Utility rate annual escalation: 3 percent;
- MCE FIT: $0.10/kWh;
- PG&E E-BioMAT FIT: $0.12772/kWh;

- Additional volatile solids (VS) to maximize digester gas production is 15,000 lbs/day;
- Food waste makes up 50 percent of additional VS – 14 tons of food waste per day (calculation assumes 30 percent solid and 88 percent of the solids are volatile - Source: http://www.nrel.gov/docs/fy13osti/57082.pdf)[2];
- FOG makes up the other 50% of additional VS – 12,000 gal FOG/day (calculation assumes that FOG contains 8 percent solids of which 95 percent is volatile and the specific gravity of FOG is 1; Source:http://www.njcleanenergy.com/files/file/Renewable_Programs/REIP/BergenCountyUtil%20AuthFeasStudy413.pdf)[1];
- Tipping fee is $400 per day[3];and does not escalate over time;
- The cost of required interconnection upgrades on PG&E's side of the distribution network is not included in this analysis;
- The existing 750 kW plus 950 kW scenario and the new 1,500 kW generator scenario requires equipment to thicken the feedstock. The cost of this equipment and improvements necessary to accommodate additional organic waste at the existing receiving station are not included in this analysis.

Options Evaluated

Marin Clean Energy (MCE)

MCE, the community choice aggregation (CCA) program that provides electric power to Marin County and surrounding communities, procures locally produced, distributed renewable generation through a feed-in-tariff (FIT) for up to 1 MW of capacity. The MCE FIT currently pays $0.10/kWh over a 20-year term for electricity generated from baseload generators like co-generation engines. Three scenarios under MCE are analyzed; one involves optimizing the existing 750 kW co-generation engine to operate near full capacity, the second scenario involves adding an additional 600 kW engine to run in parallel with the existing 750 kW generator, and the third involves adding an additional 950 kW engine to the existing 750 kW generator.

When fully powered, there are times when the existing generator will produce more power than is required by the plant and there will be other times when the plant demand is greater than the generator production. So within the optimized existing 750 kW generator scenario, we analyzed three approaches. The first approach is to utilize all of the output of the existing generator operating at full load on-site, through a "net metering" arrangement with MCE in which the excess site power is exported to the grid and the additional site power needs are

[2] CMSA'S historical volatile solid composition of food waste (21% solid and 91% of the solids are volatile) and FOG (3% solids of which 90% is volatile) differs from what is assumed in this calculation. A thorough analysis of the assumed feedstock composition should be completed in the next phase of study to determine the appropriate sizing of future food waste/FOG handling facility improvements.

[3] Assumes tipping fee of $21.61/ton food waste and $0.01/gal FOG

supplied by MCE under the applicable net metering tariff (“Net Metering with MCE”). Under net metering, the value of excess electricity is “banked” when generation is greater than demand and “withdrawn” when generation is less than demand. The second approach is for CMSA to utilize all of the output of the existing generator operating at full load on-site and sell the excess power to MCE while buying remaining electricity needs from MCE (“offset, sell, and MCE purchases”). The third approach is for CMSA to sell all the production from the generator to MCE and re-purchase the power required for site operations from MCE under their appropriate tariff (“sell all, supply all from MCE”). In all three approaches, the electrical upgrade costs are assumed to be incorporated into the generator expansion scenario and not included in this analysis.

PG&E

Pacific Gas and Electric (PG&E) offers a Feed-In Tariff (FIT) for bio-gas powered generators, the Bioenergy Market Adjusting Tariff (E-BioMAT). The FIT is a fixed price over the term of the agreement which adjusts based on market acceptance and market depth and also offers power purchase agreement (PPA) terms over 10, 15, and 20 years. The E-BioMAT FIT presently pays a contract price of $0.128/kWh for a twenty-year term arrangement. The E-BioMAT FIT began accepting offers as of February 1, 2016. Since the program has only recently begun, the contract prices have not yet changed.

Four scenarios using PG&E are analyzed; the first involves optimizing the existing 750 kW generator, using as much of the generated power on-site and selling excess electricity to PG&E. In this case, the electrical upgrade costs are assumed to be incorporated into the generator expansion scenario and are not included in this analysis. Net metering with PG&E was not analyzed as CMSA is currently a Marin Clean Energy Customer that provides power at a lower rate.

The other three scenarios analyzed were the addition of a 600 and 950 W generator and installing a 1500 new kW system as the prime generator while utilizing the existing generator as back-up.

Results of the Economic Analysis

Phase 1- Maximizing the Existing Engine

The analysis shows that for optimizing the existing 750 kW generator, the best option for CMSA is to maintain on-site use of as much of the co-generator output operating at full load as possible and selling excess power to PG&E during periods when supply is greater than demand. This scenario includes continuing to purchase power needs from MCE when demand is greater than supply. This case is projected to save CMSA approximately $131,000 in the first year and $1.828 million net present value over the twenty-year period.This is roughly equivalent to the selling to MCE option with a first year saving of $112,000 and a twenty year NPV of $1.88 million.

The table below summarizes the comparative Year 1 cost and 20-year NPV relative to the "do nothing" base case for each of the options.

Table 8-1 Existing System At Full Output				
MCE Scenarios	First Year Cost [1]	Savings over Basecase	Net Present Value [1]	NPV Savings Over Basecase
Existing 750 kW (offset and MCE purchases) - basecase	$ (181,000)	N/A	$ (3,503,000)	N/A
Optimize Existing 750 kW (sell all, supply all from MCE)	$ (110,000)	$ 71,000	$ (4,090,000)	$ (587,000)
Optimize Existing 750 kW (Net Metering with MCE)	$ (100,000)	$ 81,000	$ (2,041,000)	$ 1,462,000
Optimize Existing 750 kW (offset, sell, and MCE purchases)	$ (69,000)	$ 112,000	$ (1,615,000)	$ 1,888,000
PG&E Scenarios				
Optimize Existing 750 kW (offset, sell to PG&E)	$ (50,000)	$ 131,000	$ (1,688,000)	$ 1,815,000

Phase 2- Additional Generator

Under the existing 750 kW plus a new 600 kW or 950 kW generator scenario, two approaches are available - selling the output to MCE or PG&E.

The analysis also considered a case in which a new 1500 kW generator was installed and the existing generator used only as a backup. Only the sale to PG&E option was analyzed for this case as MCE caps their FIT program at a maximum 1000 kW project capacity.

Each of these cases is discussed below.

600 kW New Generator

As shown in Table 8-2, selling the output of the new engine to PG&E has the highest level of net income. With the CWSRF grant, the project nets CMSA approximately $260,000 in the first full year of operation and $3.4 million net present value over a twenty year period. Without the grant, the project still is projected to return $100,000 in the first year and $845,000 on a twenty-year NPV basis. Selling to MCE at its current FIT rate reduces the benefit to CMSA to approximately $2.1 million NPV with the grant. However, if the CWSRF grant is unavailable, the NPV becomes negative meaning that the revenues do not cover owning and operating costs of the new system.

Table 8-2 Existing System Plus New 600 kW Engine		
MCE Scenarios	First Year Net Income [1]	Net Present Value [1]
Existing 750 kW plus new 600 kW	$ 170,000	$ 2,070,000
Existing 750 kW plus new 600 kW (no CWSRF grant)	$ 10,000	$ (486,000)
PG&E Scenarios		
Existing 750 kW plus new 600 kW	$ 260,000	$ 3,403,000
Existing 750 kW plus new 600 kW (no CWSRF grant)	$ 100,000	$ 845,000

950 kW New Generator

Provided there is adequate additional organic materials available and the cost to receive and process them isn't too high, the larger 950 kW second generator case improves the Project's economics. This is shown in Table 8-3. Selling to PG&E continues to provide the best return to CMSA. The PG&E cases provide a NPV return of $7.3 million with the CWSRF grant and $3.8 million without the grant. The options related to selling the power to

MCE provide positive, albeit lower results. With the CWSRF grant, the projected NPV is almost $4.5 million and the “no CWSRF grant case” provides a projected return of over $900,000.

Table 8-3 Existing Sysem Plus New 950 kW Engine		
MCE Scenarios	**First Year Net Income [1]**	**Net Present Value [1]**
Existing 750 kW plus new 950 kW	$ 340,000	$ 4,456,000
Existing 750 kW plus new 950 kW (no CWSRF grant)	$ 110,000	$ 943,000
PG&E Scenarios		
Existing 750 kW plus new 950 kW	$ 520,000	$ 7,300,000
Existing 750 kW plus new 950 kW (no CWSRF grant)	$ 290,000	$ 3,787,000

1500 kW New Generator

A new 1,500 kW generator to replace the existing generator and provide additional capacity for power export has an NPV of $1.5 million. However, without the CWSRF grant, the net present value is $2.1 million, indicating that the revenues do not cover the higher cost of installing the larger engine. The summary of these values is shown in the table below.

PG&E Scenarios	First Year Net Income [1]	Net Present Value [1]
New 1500 kW	$ 140,000	$ 1,527,000
New 1500 kW (no CWSRF grant)	$ (90,000)	$ (2,110,000)

Findings and Conclusions

The economic analysis shows that for optimizing the existing 750 kW generator scenarios, maintaining direct on-site use of as much of the output as possible while selling the excess generation to PG&E through the Bio-MAT Program is the most economically beneficial.

As for adding new generation to the CMSA site to allow exporting of additional renewable power, the most beneficial scenario (highest NPV) is adding the 950 kW generator and selling the output to PG&E through the E-BioMAT FIT. The NPV for exporting power to PG&E is significantly higher than the comparable MCE scenario - $7.3 million for PG&E compared to $4.5 million for MCE. If the CWSRF grant is unavailable, the PG&E scenario NPV declines to $3.8 million and the MCE scenario NPV falls to $0.9 million.

Although the PG&E scenario has the highest NPV, there are a number of caveats to exclusively pursuing this path including:

1. The process for selling power to PG&E involves first entering into a project queue in which the seller is not guaranteed to be selected to sell power.
2. Once enrolled in the PG&E FIT, the seller cannot develop an additional power exporting project which may limit future flexibility.

3. Additional costs and requirements such as establishing a California Independent System Operator (CAISO) meter and completing other CAISO related agreements are not included in this analysis.

Based on these caveats and the willingness MCE has shown to work cooperatively with CMSA, we recommend that CMSA hold discussions with MCE to determine if arrangements with economic levels comparable to what would be obtained under the PG&E scenario can be developed. Concurrently, we recommend engaging PG&E to determine the level of interest and participation in E-BioMAT FIT in order to gauge the likelihood of successfully selling power to them at the current rate and as a fall-back, if the MCE negotiations are unsuccessful.

These economic analyses are based on various assumptions as to the characterization and quantities of food waste and FOG, as supplied by CMSA and various published sources. Because the projection of the types, quantities, and gas generation capabilities of these organic waste sources significantly affects the economics, we recommend that a more in-depth evaluation of this topic be performed in the next phase of work on this project.

Appendix A

Life Cycle Cost Analyses

Economic Analysis: Existing Generator (basecase)

Discount Rate	2.50%							
Debt interest rate	1.70%							
Turn-key Plant Cost	$0							
Electrical upgrades								
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Annual Energy Production	0	0	0	0	0	0	0	0
Energy value	$0.110	$0.110	$0.110	$0.110	$0.110	$0.110	$0.110	$0.110
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Generation value	$0	$0	$0	$0	$0	$0	$0	$0
Annual Benefits	$0	$0	$0	$0	$0	$0	$0	$0
Costs								
Finance Payment	$0	$0	$0	$0	$0	$0	$0	$0
Operations and Maintenance	$109,000	$111,180	$113,404	$115,672	$117,985	$120,345	$122,752	$125,207
Insurance	$0	$0	$0	$0	$0	$0	$0	$0
MCE electricity	$72,000	$74,160	$76,385	$78,676	$81,037	$83,468	$85,972	$88,551
PG&E costs (PPP, DWR bond, etc.)								
Annual Costs	$181,000	$185,340	$189,788	$194,348	$199,022	$203,813	$208,723	$213,758
Annual Cash Flows	-$181,000	-$185,340	-$189,788	-$194,348	-$199,022	-$203,813	-$208,723	-$213,758
Cumulative Cash Flows	-$181,000	-$366,340	-$556,128	-$750,476	-$949,498	-$1,153,311	-$1,362,034	-$1,575,792

30-Year Analysis Results

Real Value of Lifecycle Cash Flow ($2017)	$ (4,583,080.3)
NPV of lifecycle cash flow	$ (3,503,022.5)
Average Annual Cash Flow ($2017)	$ (152,769.3)
Years to Cash Flow Positive	
NPV of Costs	$ 3,503,022.5
NPV of kWh	$ -
Levelized Cost of Energy	#DIV/0!
Return on Investment	#DIV/0!
Benefit-Cost Ratio	0.00

9	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**TOTAL 20 YEARS**
0	0	0	0	0	0	0	0	0	0	0	0	0
$0.110	$0.110	$0.110	$0.110	$0.110	$0.110	$0.110	$0.110	$0.110	$0.110	$0.110	$0.110	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$127,711	$130,265	$132,870	$135,528	$138,238	$141,003	$143,823	$146,700	$149,634	$152,626	$155,679	$158,792	$2,648,413
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$91,207	$93,944	$96,762	$99,665	$102,655	$105,734	$108,906	$112,174	$115,539	$119,005	$122,575	$126,252	
$218,918	$224,209	$229,632	$235,193	$240,893	$246,738	$252,730	$258,873	$265,173	$271,631	$278,254	$285,045	$4,583,080
-$218,918	-$224,209	-$229,632	-$235,193	-$240,893	-$246,738	-$252,730	-$258,873	-$265,173	-$271,631	-$278,254	-$285,045	-$4,583,080
-$1,794,710	-$2,018,919	-$2,248,551	-$2,483,744	-$2,724,637	-$2,971,375	-$3,224,104	-$3,482,978	-$3,748,150	-$4,019,781	-$4,298,035	-$4,583,080	#REF!

Economic Analysis: Existing Generator max sell excess to MCE

Discount Rate	2.50%	
Debt interest rate	1.70%	
Turn-key Plant Cost	$0	
Electrical upgrades		The electrical upgrade cost of $593,125 is assumed to be included in the expansion scenario

	1	2	3	4	5	6	7	8
Annual Energy Production	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000
Energy value	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Generation value	$66,900	$66,900	$66,900	$66,900	$66,900	$66,900	$66,900	$66,900
Tipping fee	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820
Annual Benefits	$91,720	$91,720	$91,720	$91,720	$91,720	$91,720	$91,720	$91,720
Costs								
Finance Payment	$0	$0	$0	$0	$0	$0	$0	$0
Operations and Maintenance	$128,000	$130,560	$133,171	$135,835	$138,551	$141,322	$144,149	$147,032
Insurance	$0	$0	$0	$0	$0	$0	$0	$0
MCE electricity	$32,252	$33,219	$34,216	$35,242	$36,300	$37,389	$38,510	$39,666
PG&E costs (PPP, DWR bond, etc.)								
Annual Costs	$160,252	$163,779	$167,387	$171,077	$174,851	$178,711	$182,659	$186,697
Annual Cash Flows	-$68,532	-$72,059	-$75,667	-$79,357	-$83,131	-$86,991	-$90,939	-$94,977
Cumulative Cash Flows	-$68,532	-$140,591	-$216,258	-$295,615	-$378,746	-$465,737	-$556,676	-$651,654

30-Year Analysis Results	
Real Value of Lifecycle Cash Flow ($2017)	$ (2,142,281.3)
NPV of lifecycle cash flow	$ (1,614,638.5)
Average Annual Cash Flow ($2017)	$ (71,409)
Years to Cash Flow Positive	
NPV of Costs	$ 3,044,476.5
NPV of kWh	$ 10,429,149.6
Levelized Cost of Energy	$ 0.29
Return on Investment	#DIV/0!
Benefit-Cost Ratio	0.46

9	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**TOTAL 20 YEARS**
669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	13,380,000
$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$66,900	$66,900	$66,900	$66,900	$66,900	$66,900	$66,900	$66,900	$66,900	$66,900	$66,900	$66,900	$1,338,000
$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	
$91,720	$91,720	$91,720	$91,720	$91,720	$91,720	$91,720	$91,720	$91,720	$91,720	$91,720	$91,720	$1,834,400
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$149,972	$152,972	$156,031	$159,152	$162,335	$165,582	$168,893	$172,271	$175,717	$179,231	$182,816	$186,472	$3,110,063
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$40,856	$42,081	$43,344	$44,644	$45,983	$47,363	$48,784	$50,247	$51,755	$53,307	$54,907	$56,554	
$190,828	$195,053	$199,375	$203,796	$208,318	$212,945	$217,677	$222,518	$227,471	$232,538	$237,722	$243,026	$3,976,681
-$99,108	-$103,333	-$107,655	-$112,076	-$116,598	-$121,225	-$125,957	-$130,798	-$135,751	-$140,818	-$146,002	-$151,306	-$2,142,281
-$750,762	-$854,095	-$961,750	-$1,073,826	-$1,190,424	-$1,311,649	-$1,437,606	-$1,568,404	-$1,704,155	-$1,844,974	-$1,990,976	-$2,142,281	#REF!

Economic Analysis: Existing Generator max - NEM w/ MCE

Discount Rate	2.50%
Debt interest rate	1.70%
Turn-key Plant Cost	$0
Electrical upgrades	The electrical upgrade cost of $593,125 is assumed to be included in the expansion scenario

	1	2	3	4	5	6	7	8
Annual Energy Production	531,000	531,000	531,000	531,000	531,000	531,000	531,000	531,000
Energy value	$0.040	$0.040	$0.040	$0.040	$0.040	$0.040	$0.040	$0.040
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Generation value	$21,240	$21,240	$21,240	$21,240	$21,240	$21,240	$21,240	$21,240
Tipping fee	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820
Annual Benefits	$46,060	$46,060	$46,060	$46,060	$46,060	$46,060	$46,060	$46,060
Costs								
Finance Payment	$0	$0	$0	$0	$0	$0	$0	$0
Operations and Maintenance	$128,000	$130,560	$133,171	$135,835	$138,551	$141,322	$144,149	$147,032
Insurance	$0	$0	$0	$0	$0	$0	$0	$0
MCE electricity	$18,300	$18,849	$19,414	$19,997	$20,597	$21,215	$21,851	$22,507
PG&E costs (PPP, DWR bond, etc.)								
Annual Costs	$146,300	$149,409	$152,586	$155,832	$159,148	$162,537	$166,000	$169,538
Annual Cash Flows	-$100,240	-$103,349	-$106,526	-$109,772	-$113,088	-$116,477	-$119,940	-$123,478
Cumulative Cash Flows	-$100,240	-$203,589	-$310,115	-$419,886	-$532,974	-$649,451	-$769,391	-$892,870

30-Year Analysis Results

Real Value of Lifecycle Cash Flow ($2017)	$ (2,680,591.2)
NPV of lifecycle cash flow	$ (2,041,216.9)
Average Annual Cash Flow ($2017)	$ (89,353)
Years to Cash Flow Positive	
NPV of Costs	$ 2,759,253.7
NPV of kWh	$ 8,277,845.2
Levelized Cost of Energy	$ 0.33
Return on Investment	#DIV/0!
Benefit-Cost Ratio	0.26

9	10	11	12	13	14	15	16	17	18	19	20	TOTAL 20 YEARS
531,000	531,000	531,000	531,000	531,000	531,000	531,000	531,000	531,000	531,000	531,000	531,000	10,620,000
$0.040	$0.040	$0.040	$0.040	$0.040	$0.040	$0.040	$0.040	$0.040	$0.040	$0.040	$0.040	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$21,240	$21,240	$21,240	$21,240	$21,240	$21,240	$21,240	$21,240	$21,240	$21,240	$21,240	$21,240	$424,800
$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	
$46,060	$46,060	$46,060	$46,060	$46,060	$46,060	$46,060	$46,060	$46,060	$46,060	$46,060	$46,060	$921,200
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$149,972	$152,972	$156,031	$159,152	$162,335	$165,582	$168,893	$172,271	$175,717	$179,231	$182,816	$186,472	$3,110,063
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$23,182	$23,877	$24,594	$25,331	$26,091	$26,874	$27,680	$28,511	$29,366	$30,247	$31,155	$32,089	
$173,154	$176,849	$180,625	$184,483	$188,426	$192,456	$196,574	$200,782	$205,083	$209,478	$213,970	$218,561	$3,601,791
-$127,094	-$130,789	-$134,565	-$138,423	-$142,366	-$146,396	-$150,514	-$154,722	-$159,023	-$163,418	-$167,910	-$172,501	-$2,680,591
-$1,019,964	-$1,150,753	-$1,285,318	-$1,423,742	-$1,566,108	-$1,712,504	-$1,863,017	-$2,017,739	-$2,176,762	-$2,340,180	-$2,508,090	-$2,680,591	#REF!

Economic Analysis: Existing Generator max sell all, buy all MCE

Discount Rate	2.50%
Debt interest rate	1.70%
Turn-key Plant Cost	$0
Electrical upgrades	The electrical upgrade cost of $593,125 is assumed to be included in the expansion scenario

	1	2	3	4	5	6	7	8
Annual Energy Production for export	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000
FIT Rate	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Power sales revenue	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000
Tipping fee	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820
Annual Benefits	$668,820	$668,820	$668,820	$668,820	$668,820	$668,820	$668,820	$668,820
Costs								
Finance Payment	$0	$0	$0	$0	$0	$0	$0	$0
Operations and Maintenance	$128,000	$130,560	$133,171	$135,835	$138,551	$141,322	$144,149	$147,032
Insurance	$0	$0	$0	$0	$0	$0	$0	$0
MCE electricity	$651,024	$664,044	$677,325	$690,872	$704,689	$718,783	$733,159	$747,822
PG&E costs (PPP, DWR bond, etc.)								
Annual Costs	$779,024	$794,604	$810,497	$826,707	$843,241	$860,105	$877,308	$894,854
Annual Cash Flows	-$110,204	-$125,784	-$141,677	-$157,887	-$174,421	-$191,285	-$208,488	-$226,034
Cumulative Cash Flows	-$110,204	-$235,988	-$377,665	-$535,552	-$709,972	-$901,258	-$1,109,745	-$1,335,779

30-Year Analysis Results

Real Value of Lifecycle Cash Flow ($2017)	$ (5,551,834)
NPV of lifecycle cash flow	$ (4,089,909)
Average Annual Cash Flow ($2017)	$ (185,061.1)
Years to Cash Flow Positive	
NPV of Costs	$ 14,516,252.4
NPV of kWh	$100,394,205.1
Levelized Cost of Energy	$ 0.14
Return on Investment	#DIV/0!
Benefit-Cost Ratio	0.71

9	10	11	12	13	14	15	16	17	18	19	20	TOTAL 20 YEARS
6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	6,440,000	128,800,000
$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$12,880,000
$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820	
$668,820	$668,820	$668,820	$668,820	$668,820	$668,820	$668,820	$668,820	$668,820	$668,820	$668,820	$668,820	$13,376,400
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$149,972	$152,972	$156,031	$159,152	$162,335	$165,582	$168,893	$172,271	$175,717	$179,231	$182,816	$186,472	$3,110,063
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$762,778	$778,034	$793,595	$809,467	$825,656	$842,169	$859,012	$876,193	$893,716	$911,591	$929,823	$948,419	
$912,751	$931,006	$949,626	$968,618	$987,991	$1,007,751	$1,027,906	$1,048,464	$1,069,433	$1,090,822	$1,112,638	$1,134,891	$18,928,234
-$243,931	-$262,186	-$280,806	-$299,798	-$319,171	-$338,931	-$359,086	-$379,644	-$400,613	-$422,002	-$443,818	-$466,071	-$5,551,834
-$1,579,710	-$1,841,895	-$2,122,701	-$2,422,500	-$2,741,671	-$3,080,601	-$3,439,687	-$3,819,331	-$4,219,944	-$4,641,945	-$5,085,763	-$5,551,834	#REF!

Economic Analysis: Existing Generator plus new 600 kW generator - MCE

Discount Rate	2.50%	-CMSA stated Rate
Debt interest rate	1.70%	-CWSFR loan Rate
Turn-key Plant Cost	$4,452,000	
Electrical upgrades	$1,166,025	
CWSRF Green Project Reserve Loan Forgiveness	$ 2,809,013	

	1	2	3	4	5	6	7	8
Annual Energy Production for export	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200
FIT Rate	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Power sales revenue	$411,120	$411,120	$411,120	$411,120	$411,120	$411,120	$411,120	$411,120
Capacity payment	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000
Tipping fee	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800
Annual Benefits	$551,920	$551,920	$551,920	$551,920	$551,920	$551,920	$551,920	$551,920
Costs								
Finance Payment	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068
Operations and Maintenance	$213,300	$217,566	$221,917	$226,356	$230,883	$235,500	$240,210	$245,015
Insurance		$0	$0	$0	$0	$0	$0	$0
Annual Costs	$377,368	$381,634	$385,985	$390,423	$394,950	$399,568	$404,278	$409,082
Annual Cash Flows	$174,552	$170,286	$165,935	$161,497	$156,970	$152,352	$147,642	$142,838
Cumulative Cash Flows	$174,552	$344,839	$510,774	$672,270	$829,240	$981,592	$1,129,234	$1,272,071

30-Year Analysis Results

Real Value of Lifecycle Cash Flow ($2017)	$ 2,574,417.9
NPV of lifecycle cash flow	$ 2,071,683.0
Average Annual Cash Flow ($2017)	$ 85,813.9
Years to Cash Flow Positive	
NPV of Costs	$ 6,532,287.4
NPV of kWh	$ 64,090,164.0
Levelized Cost of Energy	$ 0.10
Return on Investment	#DIV/0!
Benefit-Cost Ratio	1.30

9	10	11	12	13	14	15	16	17	18	19	20	TOTAL 20 YEARS
4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	82,224,000
$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$411,120	$411,120	$411,120	$411,120	$411,120	$411,120	$411,120	$411,120	$411,120	$411,120	$411,120	$411,120	$8,222,400
$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	
$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	
$551,920	$551,920	$551,920	$551,920	$551,920	$551,920	$551,920	$551,920	$551,920	$551,920	$551,920	$551,920	$11,038,400
$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$3,281,353
$249,915	$254,913	$260,012	$265,212	$270,516	$275,926	$281,445	$287,074	$292,815	$298,671	$304,645	$310,738	$5,182,629
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$413,983	$418,981	$424,079	$429,279	$434,584	$439,994	$445,512	$451,141	$456,883	$462,739	$468,713	$474,805	$8,463,982
$137,937	$132,939	$127,841	$122,641	$117,336	$111,926	$106,408	$100,779	$95,037	$89,181	$83,207	$77,115	$2,574,418
$1,410,009	$1,542,948	$1,670,789	$1,793,429	$1,910,766	$2,022,692	$2,129,099	$2,229,878	$2,324,915	$2,414,096	$2,497,303	$2,574,418	#REF!

Economic Analysis: Existing Generator plus new 950 kW generator - MCE

Discount Rate	2.50%	-CMSA stated Rate
Debt interest rate	1.70%	-CWSFR loan Rate
Turn-key Plant Cost	$6,406,000	
Electrical upgrades	$1,310,175	
CWSRF Green Project Reserve Loan Forgiveness	$ 3,858,088	

	1	2	3	4	5	6	7	8
Annual Energy Production for export	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800
FIT Rate	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Power sales revenue	$658,280	$658,280	$658,280	$658,280	$658,280	$658,280	$658,280	$658,280
Capacity payment	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000
Tipping fee	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000
Annual Benefits	$828,280	$828,280	$828,280	$828,280	$828,280	$828,280	$828,280	$828,280
Costs								
Finance Payment	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342
Operations and Maintenance	$265,300	$270,606	$276,018	$281,538	$287,169	$292,913	$298,771	$304,746
Insurance		$0	$0	$0	$0	$0	$0	$0
Annual Costs	$490,642	$495,948	$501,360	$506,880	$512,511	$518,254	$524,112	$530,088
Annual Cash Flows	$337,638	$332,332	$326,920	$321,400	$315,769	$310,026	$304,168	$298,192
Cumulative Cash Flows	$337,638	$669,971	$996,891	$1,318,291	$1,634,060	$1,944,086	$2,248,253	$2,546,445

30-Year Analysis Results

Real Value of Lifecycle Cash Flow ($2017)	$ 5,612,675.7
NPV of lifecycle cash flow	$ 4,455,731.8
Average Annual Cash Flow ($2017)	$ 187,089.19
Years to Cash Flow Positive	
NPV of Costs	$ 8,456,459.5
NPV of kWh	$102,620,337.5
Levelized Cost of Energy	$ 0.08
Return on Investment	#DIV/0!
Benefit-Cost Ratio	1.51

9	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**TOTAL 20 YEARS**
6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	131,656,000
$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	$0.100	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$658,280	$658,280	$658,280	$658,280	$658,280	$658,280	$658,280	$658,280	$658,280	$658,280	$658,280	$658,280	$13,165,600
$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	
$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	
$828,280	$828,280	$828,280	$828,280	$828,280	$828,280	$828,280	$828,280	$828,280	$828,280	$828,280	$828,280	$16,565,600
$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$4,506,832
$310,841	$317,058	$323,399	$329,867	$336,465	$343,194	$350,058	$357,059	$364,200	$371,484	$378,914	$386,492	$6,446,092
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$536,183	$542,400	$548,741	$555,209	$561,806	$568,535	$575,399	$582,400	$589,542	$596,826	$604,255	$611,834	$10,952,924
$292,097	$285,880	$279,539	$273,071	$266,474	$259,745	$252,881	$245,880	$238,738	$231,454	$224,025	$216,446	$5,612,676
$2,838,543	$3,124,423	$3,403,962	$3,677,033	$3,943,507	$4,203,252	$4,456,132	$4,702,012	$4,940,750	$5,172,205	$5,396,229	$5,612,676	#REF!

Economic Analysis: Existing Generator (sell to PG&E, buy from MCE grid)

Discount Rate	2.50%
Debt interest rate	1.70%
Turn-key Plant Cost	$0
Electrical upgrades	The electrical upgrade cost of $593,125 is assumed to be included in the expansion scenario

	1	2	3	4	5	6	7	8
Annual Energy Production	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000
Energy value	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Generation value	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445
Tipping fee	$24,820							
Annual Benefits	$110,265	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445
Costs								
Finance Payment	$0	$0	$0	$0	$0	$0	$0	$0
Operations and Maintenance	$128,000	$130,560	$133,171	$135,835	$138,551	$141,322	$144,149	$147,032
Insurance	$0	$0	$0	$0	$0	$0	$0	$0
MCE electricity	$32,252	$33,219	$34,216	$35,242	$36,300	$37,389	$38,510	$39,666
PG&E costs (PPP, DWR bond, etc.)								
Annual Costs	$160,252	$163,779	$167,387	$171,077	$174,851	$178,711	$182,659	$186,697
Annual Cash Flows	-$49,987	-$78,335	-$81,942	-$85,632	-$89,406	-$93,266	-$97,214	-$101,253
Cumulative Cash Flows	-$49,987	-$128,322	-$210,264	-$295,897	-$385,303	-$478,569	-$575,784	-$677,036

30-Year Analysis Results

Real Value of Lifecycle Cash Flow ($2017)	$ (2,242,967.7)
NPV of lifecycle cash flow	$ (1,688,250.9)
Average Annual Cash Flow ($2017)	$ (74,766)
Years to Cash Flow Positive	
NPV of Costs	$ 3,044,476.5
NPV of kWh	$ 10,429,149.6
Levelized Cost of Energy	$ 0.29
Return on Investment	#DIV/0!
Benefit-Cost Ratio	0.44

9	10	11	12	13	14	15	16	17	18	19	20	TOTAL 20 YEARS
669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	669,000	13,380,000
$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$1,708,894
$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$85,445	$1,733,714
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$149,972	$152,972	$156,031	$159,152	$162,335	$165,582	$168,893	$172,271	$175,717	$179,231	$182,816	$186,472	$3,110,063
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$40,856	$42,081	$43,344	$44,644	$45,983	$47,363	$48,784	$50,247	$51,755	$53,307	$54,907	$56,554	
$190,828	$195,053	$199,375	$203,796	$208,318	$212,945	$217,677	$222,518	$227,471	$232,538	$237,722	$243,026	$3,976,681
-$105,383	-$109,608	-$113,930	-$118,351	-$122,874	-$127,500	-$132,232	-$137,074	-$142,027	-$147,094	-$152,277	-$157,581	-$2,242,968
-$782,420	-$892,028	-$1,005,959	-$1,124,310	-$1,247,183	-$1,374,683	-$1,506,916	-$1,643,989	-$1,786,016	-$1,933,109	-$2,085,387	-$2,242,968	#REF!

Economic Analysis: Existing Generator plus new 600 kW generator - PG&E

Discount Rate	2.50%
Debt interest rate	1.70%
Turn-key Plant Cost	$4,452,000
Electrical upgrades	$1,166,025
CWSRF Green Project Reserve Loan Forgiveness	$ 2,809,013

	1	2	3	4	5	6	7	8
Annual Energy Production for export	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200
FIT Rate	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Power sales revenue	$525,082	$525,082	$525,082	$525,082	$525,082	$525,082	$525,082	$525,082
Tipping fee	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800
Annual Benefits	$641,882	$641,882	$641,882	$641,882	$641,882	$641,882	$641,882	$641,882
Costs								
Finance Payment	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068
Operations and Maintenance	$213,300	$217,566	$221,917	$226,356	$230,883	$235,500	$240,210	$245,015
Insurance	$0	$0	$0	$0	$0	$0	$0	$0
Annual Costs	$377,368	$381,634	$385,985	$390,423	$394,950	$399,568	$404,278	$409,082
Annual Cash Flows	$264,515	$260,249	$255,897	$251,459	$246,932	$242,314	$237,604	$232,800
Cumulative Cash Flows	$264,515	$524,764	$780,661	$1,032,120	$1,279,052	$1,521,367	$1,758,971	$1,991,771

30-Year Analysis Results

Real Value of Lifecycle Cash Flow ($2017)	$ 4,256,867
NPV of lifecycle cash flow	$ 3,402,842.82
Average Annual Cash Flow ($2017)	$ 141,895.6
Years to Cash Flow Positive	2
NPV of Costs	$ 6,532,287
NPV of kWh	64,090,164
Levelized Cost of Energy	$ 0.102
Return on Investment	#DIV/0!
Benefit-Cost Ratio	1.50

9	10	11	12	13	14	15	16	17	18	19	20	TOTAL 20 YEARS
4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	4,111,200	82,224,000
$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$525,082	$525,082	$525,082	$525,082	$525,082	$525,082	$525,082	$525,082	$525,082	$525,082	$525,082	$525,082	$10,501,649
$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	$116,800	
$641,882	$641,882	$641,882	$641,882	$641,882	$641,882	$641,882	$641,882	$641,882	$641,882	$641,882	$525,082	$12,720,849
$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$164,068	$3,281,353
$249,915	$254,913	$260,012	$265,212	$270,516	$275,926	$281,445	$287,074	$292,815	$298,671	$304,645	$310,738	$5,182,629
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$413,983	$418,981	$424,079	$429,279	$434,584	$439,994	$445,512	$451,141	$456,883	$462,739	$468,713	$474,805	$8,463,982
$227,900	$222,902	$217,803	$212,603	$207,299	$201,889	$196,370	$190,741	$185,000	$179,143	$173,170	$50,277	$4,256,867
$2,219,671	$2,442,573	$2,660,376	$2,872,979	$3,080,278	$3,282,166	$3,478,536	$3,669,277	$3,854,277	$4,033,420	$4,206,590	$4,256,867	#REF!

Economic Analysis: Existing Generator plus new 950 kW generator - PG&E

Discount Rate	2.50%	-CMSA stated Rate
Debt interest rate	1.70%	-CWSFR loan Rate
Turn-key Plant Cost	$6,406,000	
Electrical upgrades	$1,310,175	
CWSRF Green Project Reserve Loan Forgiveness	$ 3,858,088	

	1	2	3	4	5	6	7	8
Annual Energy Production for export	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800
FIT Rate	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Power sales revenue	$840,755	$840,755	$840,755	$840,755	$840,755	$840,755	$840,755	$840,755
Capacity payment	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000
Tipping fee	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000
Annual Benefits	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755
Costs								
Finance Payment	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342
Operations and Maintenance	$265,300	$270,606	$276,018	$281,538	$287,169	$292,913	$298,771	$304,746
Insurance		$0	$0	$0	$0	$0	$0	$0
Annual Costs	$490,642	$495,948	$501,360	$506,880	$512,511	$518,254	$524,112	$530,088
Annual Cash Flows	$520,114	$514,808	$509,395	$503,875	$498,244	$492,501	$486,643	$480,667
Cumulative Cash Flows	$520,114	$1,034,921	$1,544,317	$2,048,192	$2,546,436	$3,038,937	$3,525,580	$4,006,247

30-Year Analysis Results

Real Value of Lifecycle Cash Flow ($2017)	$ 9,262,180.0
NPV of lifecycle cash flow	$ 7,300,367.6
Average Annual Cash Flow ($2017)	$ 308,739.33
Years to Cash Flow Positive	
NPV of Costs	$ 8,456,459.5
NPV of kWh	$102,620,337.5
Levelized Cost of Energy	$ 0.08
Return on Investment	#DIV/0!
Benefit-Cost Ratio	1.85

9	10	11	12	13	14	15	16	17	18	19	20	TOTAL 20 YEARS
6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	6,582,800	131,656,000
$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	$0.128	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$840,755	$840,755	$840,755	$840,755	$840,755	$840,755	$840,755	$840,755	$840,755	$840,755	$840,755	$840,755	$16,815,104
$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	$24,000	
$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	
$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$1,010,755	$20,215,104
$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$225,342	$4,506,832
$310,841	$317,058	$323,399	$329,867	$336,465	$343,194	$350,058	$357,059	$364,200	$371,484	$378,914	$386,492	$6,446,092
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$536,183	$542,400	$548,741	$555,209	$561,806	$568,535	$575,399	$582,400	$589,542	$596,826	$604,255	$611,834	$10,952,924
$474,572	$468,356	$462,014	$455,546	$448,949	$442,220	$435,356	$428,355	$421,214	$413,930	$406,500	$398,922	$9,262,180
$4,480,820	$4,949,175	$5,411,190	$5,866,736	$6,315,685	$6,757,905	$7,193,261	$7,621,615	$8,042,829	$8,456,759	$8,863,258	$9,262,180	#REF!

Economic Analysis: new 1500 kW generator - PG&E

Discount Rate	2.50%
Debt interest rate	1.70%
Turn-key Plant Cost	$9,927,000
Electrical upgrades	$1,439,375
CWSRF Green Project Reserve Loan Forgiveness	$ 4,000,000

	1	2	3	4	5	6	7	8
Annual Energy Production for export	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700
FIT Rate	$0.127	$0.127	$0.127	$0.127	$0.127	$0.127	$0.127	$0.127
Benefits	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Power sales revenue	$664,807	$664,807	$664,807	$664,807	$664,807	$664,807	$664,807	$664,807
Tipping fee	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000
Annual Benefits	$810,807	$810,807	$810,807	$810,807	$810,807	$810,807	$810,807	$810,807
Costs								
Finance Payment	$430,252	$430,252	$430,252	$430,252	$430,252	$430,252	$430,252	$430,252
Operations and Maintenance	$236,400	$241,128	$245,951	$250,870	$255,887	$261,005	$266,225	$271,549
Insurance	$0	$0	$0	$0	$0	$0	$0	$0
Annual Costs	$666,652	$671,380	$676,203	$681,122	$686,139	$691,257	$696,477	$701,802
Annual Cash Flows	$144,155	$139,427	$134,604	$129,685	$124,668	$119,550	$114,330	$109,005
Cumulative Cash Flows	$144,155	$283,581	$418,185	$547,871	$672,538	$792,088	$906,418	$1,015,423

30-Year Analysis Results	
Real Value of Lifecycle Cash Flow ($2017)	$ 1,867,195
NPV of lifecycle cash flow	$ 1,527,475.39
Average Annual Cash Flow ($2017)	$ 62,239.8
Years to Cash Flow Positive	2
NPV of Costs	$ 11,112,325
NPV of kWh	81,604,588
Levelized Cost of Energy	$ 0.136
Return on Investment	#DIV/0!
Benefit-Cost Ratio	1.13

9	10	11	12	13	14	15	16	17	18	19	20	TOTAL 20 YEARS
5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	5,234,700	104,694,000
$0.127	$0.127	$0.127	$0.127	$0.127	$0.127	$0.127	$0.127	$0.127	$0.127	$0.127	$0.127	
2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	
$664,807	$664,807	$664,807	$664,807	$664,807	$664,807	$664,807	$664,807	$664,807	$664,807	$664,807	$664,807	$13,296,138
$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	
$810,807	$810,807	$810,807	$810,807	$810,807	$810,807	$810,807	$810,807	$810,807	$810,807	$810,807	$810,807	$16,216,138
$430,252	$430,252	$430,252	$430,252	$430,252	$430,252	$430,252	$430,252	$430,252	$430,252	$430,252	$430,252	$8,605,045
$276,980	$282,520	$288,170	$293,934	$299,812	$305,809	$311,925	$318,163	$324,527	$331,017	$337,637	$344,390	$5,743,898
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$707,233	$712,772	$718,423	$724,186	$730,065	$736,061	$742,177	$748,416	$754,779	$761,269	$767,890	$774,642	$14,348,943
$103,574	$98,035	$92,384	$86,621	$80,742	$74,746	$68,630	$62,391	$56,028	$49,538	$42,917	$36,165	$1,867,195
$1,118,998	$1,217,033	$1,309,417	$1,396,038	$1,476,780	$1,551,526	$1,620,156	$1,682,548	$1,738,576	$1,788,113	$1,831,031	$1,867,195	#REF!