

**Appendix H**  
***Alternative Energy Survey for Proposed Desalination Plant (URS 2003)***

**DRAFT REPORT**

**ALTERNATIVE ENERGY  
SURVEY FOR PROPOSED  
DESALINATION PLANT**

*Prepared for*  
Marin Municipal Water District

June 2003

**URS**

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# TABLE OF CONTENTS

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|                  |  |            |
|------------------|--|------------|
| <b>Section 1</b> | <b>Overview .....</b>  | <b>1-1</b> |
| <b>Section 2</b> | <b>Reconductoring of Existing PG&amp;E Transmission Line .....</b> | <b>2-1</b> |
|                  | 2.1 Technology Characterization .....                              | 2-1        |
|                  | 2.2 Estimated Cost of Reconductoring Alternative .....             | 2-2        |
|                  | 2.3 Key Environmental Concerns .....                               | 2-3        |
|                  | 2.4 Implementation Constraints .....                               | 2-3        |
|                  | 2.5 Schedule Implications .....                                    | 2-3        |
|                  | 2.6 References .....   | 2-3        |
| <b>Section 3</b> | <b>Rerating of Existing PG&amp;E Transmission Line .....</b>       | <b>3-1</b> |
|                  | 3.1 Technology Characterization .....                              | 3-1        |
|                  | 3.2 Estimated Cost of Reconductoring Alternative .....             | 3-1        |
|                  | 3.3 Key Environmental Concerns .....                               | 3-2        |
|                  | 3.4 Implementation Constraints .....                               | 3-2        |
|                  | 3.5 Schedule Implications .....                                    | 3-2        |
|                  | 3.6 References .....   | 3-3        |
| <b>Section 4</b> | <b>Green Energy .....</b>  | <b>4-1</b> |
|                  | 4.1 Technology Characterization .....                              | 4-1        |
|                  | 4.2 Estimated Cost of Green Electricity .....                      | 4-2        |
|                  | 4.3 Key Environmental Concerns .....                               | 4-2        |
|                  | 4.4 Implementation Constraints .....                               | 4-3        |
|                  | 4.5 Schedule Implications .....                                    | 4-3        |
|                  | 4.6 References .....   | 4-3        |
| <b>Section 5</b> | <b>Landfill Gas to Energy .....</b>                                | <b>5-1</b> |
|                  | 5.1 Technology Characterization .....                              | 5-1        |
|                  | 5.2 Estimated Cost for Landfill Gas to Energy Alternative .....    | 5-2        |
|                  | 5.3 Key Environmental Concerns .....                               | 5-3        |
|                  | 5.4 Implementation Constraints .....                               | 5-3        |
|                  | 5.5 Schedule Implications .....                                    | 5-4        |
|                  | 5.6 References .....   | 5-4        |
| <b>Section 6</b> | <b>Solar Energy .....</b>  | <b>6-1</b> |
|                  | 6.1 Technology Characterization .....                              | 6-1        |
|                  | 6.2 Anticipated Cost .....   | 6-2        |
|                  | 6.3 Key Environmental Issues .....                                 | 6-2        |
|                  | 6.4 Potential Constraints to Implementation .....                  | 6-2        |
|                  | 6.5 Schedule Implications .....                                    | 6-3        |
|                  | 6.6 References .....   | 6-3        |

# TABLE OF CONTENTS

---

|                  |  |            |
|------------------|--|------------|
| <b>Section 7</b> | <b>Fuel Cell Energy .....</b>                      | <b>7-1</b> |
|                  | 7.1 Technology Characterization .....              | 7-1        |
|                  | 7.2 Anticipated Cost.....                          | 7-2        |
|                  | 7.3 Key Environmental Issues .....                 | 7-2        |
|                  | 7.4 Potential Constraints to Implementation.....   | 7-2        |
|                  | 7.5 Schedule Implications.....                     | 7-3        |
|                  | 7.6 References.....                                | 7-3        |
| <b>Section 8</b> | <b>Natural Gas - Fired Combustion Turbine.....</b> | <b>8-1</b> |
|                  | 8.1 Technology Characterization .....              | 8-1        |
|                  | 8.2 Anticipated Cost.....                          | 8-2        |
|                  | 8.3 Key Environmental Concerns .....               | 8-2        |
|                  | 8.4 Implementation Constraints .....               | 8-2        |
|                  | 8.5 Schedule Implications.....                     | 8-2        |
|                  | 8.6 References.....                                | 8-3        |
| <b>Section 9</b> | <b>Summary .....</b>                               | <b>9-1</b> |

MMWD is considering the installation of a new seawater desalination plant to expand its current potable water supply. The desalination plant would supply up to 15 million gallons per day (mgd) of potable water and is envisioned to be developed in 5 mgd increments at an MMWD-owned site near the intersection of Pelican Way and E. Francisco Boulevard in San Rafael, California. The projected electricity requirements for the proposed desalination plant are shown in Table 1.

**Table 1  
Estimated Electricity Demand for Proposed Desalination Project (MMWD, 2003)<sup>1</sup>**

| <b>Desalination Plant Capacity, mgd</b> | <b>Maximum Potable Water Production, acre-feet</b> | <b>Maximum Annual Electricity Use, kWh</b> | <b>Peak Electricity Load, MW</b> | <b>Average Electricity Load, MW<sup>2</sup></b> |
|---|--|--|----------------------------------|---|
| 5                                       | 5,000  | 22,000,000                                 | 2.7                              | 2.5   |
| 10                                      | 10,000   | 42,000,000                                 | 5.4                              | 4.8   |
| 15                                      | 15,000   | 64,000,000                                 | 8.1                              | 7.3   |

<sup>1</sup> MMWD memorandum from Dana Roxon to Ron Thiesen, May 27, 2003. This evaluation was based on the electricity use estimates summarized for the Bahman Sheik report.

<sup>2</sup> Average load assumed equal to maximum annual energy use ÷ 8,760 hours per year

The energy requirements summarized in Table 1 indicate that the projected electricity demand for operation of a new desalination plant will be substantial, representing an 85%, 162% and 246% increase above current MMWD electricity needs for the 5 mgd, 10 mgd and 15 mgd capacity phases, respectively.

Given this formidable potential rise in electricity requirements, MMWD has retained URS to conduct a survey level analysis of alternative energy options for the proposed desalination plant. The following alternative energy scenarios have been included in this survey:

- Reconductoring of Existing PG&E Transmission Line
- Rerating of Existing PG&E Transmission Line
- Green Energy Options
- Landfill Gas to Energy
- Solar (Photovoltaic) Energy
- Fuel Cell Energy
- Natural Gas-Fired Combustion Turbine Generation

All of the above technologies are demonstrated and commercially available from multiple suppliers. Tidal energy is an emerging technology that has not yet matured to a commercial status. There are only a handful of demonstration projects underway. For this reason, tidal energy was not studied further.

Each of the above alternative energy options is described in the following sections of this review report. The technology is characterized and a general planning level capital and operating cost is presented. Environmental, implementation and schedule issues are also briefly discussed for each

option. The final section of the report is a summary of the review results. The review is intended to provide planning level information to MMWD on a range of commercially available energy alternatives that can serve as a basis for further refining MMWD's analysis of energy alternatives. The review is not intended to be an exhaustive or detailed engineering assessment of any individual technology. Such an assessment would be warranted in a subsequent effort directed toward a subset of preferred alternatives.

## 2.1 TECHNOLOGY CHARACTERIZATION

Reconductoring is a term that applies to the replacement of an existing transmission line with new conductors (wires) that have a larger current capacity (ampacity) than the existing line. When additional electrical current is drawn through an existing line, the additional current flow will cause the conductor to heat. As the conductor heats, the line tension will relax, causing additional sag in the transmission line. The heat generation is a direct function of current flow and the dissipation of this heat from the conductor is a function primarily of ambient temperature and wind speed. Overhead transmission lines have an ampacity rating that is based on maintaining the conductor below a maximum operating temperature (set to protect the life of the conductor) and a minimum ground clearance. The specific criteria are set forth in the State of California *Rules for Overhead Transmission Line Construction*, as prescribed by the California Public Utilities Commission (CPUC) in General Order 95 (GO-95). Reconductoring may involve a replacement of the existing wires or in some cases may include an overbuild of an existing of the transmission line with taller poles and larger conductors. The latter is the preferred method when it is necessary to maintain service to an area and no alternative electrical distribution exists for that service. In some instances, overhead transmission is prohibited by the local municipality, in which case, underground transmission is required. It is assumed for the purposes of this analysis that an overhead transmission line would be acceptable for the project.

In the case of the MMWD site on Pelican Way in San Rafael, the nearest substation to the site is the 115 kilovolt (kV) San Rafael substation, near the intersection of Irene Street and East Francisco Blvd. Original PG&E information regarding a proposed transmission interconnection for the site indicated the need for reconductoring of approximately 1100 feet of line along Irene Street and an additional 3800 feet along East Francisco Blvd. (*Alfaro, 1991*). The transmission to the site is currently serviced by a 12kV distribution feeder (San Rafael circuit 1103) that provides service from the San Rafael substation to a termination point at San Quentin. The feeder is rated for a maximum current flow of 600 amps and is expected to experience a peak summer load of 503 amps with the existing service. A parallel feeder (San Rafael circuit 1102) is rated for a maximum current flow of 541 amps and is expected to experience a peak summer load of 460 amps (*Regacho, 2003.*). Based on the above information, estimated peak current flow is compared below to existing line capacity below:

| Desalination Plant Size, mgd | Estimated Peak Load, kW <sup>1</sup> | Estimated Additional Current Flow, amps <sup>2</sup> | Total Current Including Existing Distribution Load <sup>3</sup> | Percent of Combined Ampacity <sup>4</sup> | Preliminary Determination-Reconductoring Needed? |
|------------------------------|--------------------------------------|--|---|---|--|
| 5                            | 2,700                                | 126  | 1089  | 95.4                                      | Maybe no <sup>5</sup>                            |
| 10                           | 5,400                                | 252  | 1215  | 106.5                                     | Yes  |
| 15                           | 8,100                                | 378  | 1341  | 117.5                                     | Yes  |

<sup>1</sup> MMWD memo from Dana Roxon to Ron Thiesen, May, 2003.

<sup>2</sup> Based on the standard power/current/voltage relationship:  $P = \sqrt{3}VI$ , where P = power, V = voltage and I = current.

<sup>3</sup> Sum of existing feeder peak flow estimates (*Regacho, 2003.*) and estimated additional current flow.

<sup>4</sup> Total current flow/combined feeder ampacity expressed as a percentage

<sup>5</sup> Assuming load shifting from one parallel circuit to the other is possible to create sufficient ampacity on one of the circuits for the new load, it may be possible to avoid reconductoring for the first phase of desalination development (*Regacho, 2003.*)

Based on the above preliminary determination and discussions with the PG&E district planning engineer (*Regacho, 2003*), it appears that it may be possible to service the first phase of the desalination plant without the need for reconductoring, provided that sufficient existing loads on circuit 1102 can be shift to circuit 1103 to create additional ampacity for the new MMWD load. A detailed PG&E evaluation would be needed to confirm this preliminary determination and would need to be coordinated by the MMWD account representative.

**2.2 ESTIMATED COST OF RECONDUCTORING ALTERNATIVE**

The cost of reconductoring a distribution feeder, if needed, could range between \$15,000 - \$50,000/km based on published information (Energy Resources International, Inc. 1999.). PG&E estimates cost based on \$40/foot (*Regacho, 2003*). Depending on whether any necessary reconductoring were performed by PG&E or by MMWD, the costs would vary substantially. It is also noteworthy that PG&E costs for reconductoring may be absorbed by PG&E depending on other planned distribution upgrades in the area, and the projected revenue associated with the additional load. Potential reconductoring costs are summarized below for each phase. These costs do not include any necessary substation upgrades, which would need to be separately determined by PG&E.

| Desalination Plant Size, mgd | Estimated Capital Cost, \$ (literature-based) <sup>1</sup> | Estimated Capital Cost, \$ (PG&E-based) <sup>2</sup> | Anticipated Electrical Consumption, kWh <sup>3</sup> | Anticipated Operating Cost, \$/yr <sup>4</sup> |
|------------------------------|--|--|--|--|
| 5                            | Possibly none – 75,000                                     | Possibly none – 75,000                               | 22,000,000   | 770,000  |
| 10                           | 75,000   | 196,000  | 42,000,000   | 5,670,000                                      |
| 15                           | 75,000   | 196,000  | 64,000,000   | 8,640,000                                      |

<sup>1</sup> Capital cost is a one-time cost for transmission upgrade (i.e. once the reconductoring is completed it is assumed that it would have sufficient capacity to service all phases of the project). The estimated cost excludes any substation upgrade costs that may be necessary. Value is based on the high end of the range reported in the literature.

<sup>2</sup> PG&E estimate and is a one-time cost for transmission upgrade (i.e. once the reconductoring is completed it is assumed that it would have sufficient capacity to service all phases of the project).

<sup>3</sup> MMWD memo from Dana Roxon to Ron Thiesen, May, 2003.

<sup>4</sup> Operating cost is based on current electrical rate of \$ 0.135/kWh and anticipated electrical.

**2.3 KEY ENVIRONMENTAL CONCERNS**

A potential environmental issue associated with a reconductoring would be the visual impact associated with either replacing existing poles with new, taller poles or possibly adding new poles to the existing feeder corridor.

**2.4 IMPLEMENTATION CONSTRAINTS**

There are no apparent implementation constraints to reconductoring. The technology is commercially available.

**2.5 SCHEDULE IMPLICATIONS**

The process of reconductoring would commence with a formal study request by the MMWD account representative. PG&E typically requires 3 – 4 months to complete the investigation, depending on the current backlog. The results of the investigation would then be reported back to MMWD in terms of an analysis of the system impact, and estimate of the costs for the upgrade and a cost proposal for the upgrade. MMWD would likely have the option to complete the upgrade itself (or by a qualified contractor under its direction) in accordance with PG&E specifications, at a likely savings. Once a signed agreement was obtained for the work, PG&E would undertake the work and could likely complete it within 4 – 6 months. (*Regacho, 2003.*)

**2.6 REFERENCES**

MMWD, 2003. *District Electrical Energy Use*. Memo from Ron Thiesen to Dana Roxon, May 27, 2003.

Energy Resources International, Inc., 1999. *Handbook of Climate Change Mitigation Options., Section 6.3 – Reducing Conductor Losses.*

<http://www.usea.org/Climatechange/chapter6/6.3.html>.

## **SECTION TWO**

## **Reconductoring of Existing PG&E Transmission Line**

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Regacho, 2003. Personal communication with David Stein, URS and Frank Regacho, PG&E District Planning Engineer, June 2003.

### 3.1 TECHNOLOGY CHARACTERIZATION

Rerating is a term that applies to the formal process of revising the ampacity of an existing transmission line. When additional electrical current is drawn through an existing line, the additional current flow will cause the conductor to heat. As the conductor heats, the line tension will relax, causing additional sag in the transmission line. The heat generation is a direct function of current flow and the dissipation of this heat from the conductor is a function primarily of ambient temperature and wind speed. Overhead transmission lines have an ampacity rating that is based on maintaining the conductor below a maximum operating temperature (set to protect the life of the conductor) and a minimum ground clearance. The specific criteria are set forth in the State of California *Rules for Overhead Transmission Line Construction*, as prescribed by the California Public Utilities Commission (CPUC) in General Order 95 (GO-95). Rerating can be accomplished when a conservatively low ambient wind speed and/or conservatively high ambient temperature were used as the basis for the rating.

Rerating of transmission lines may involve one or more of the following steps:

- comparison of ambient conditions (particularly wind speed) versus the conditions used as a basis for rating the line to determine whether an appreciable engineering margin is available;
- calculation of conductor operating temperature and sag at proposed rerating conditions;
- physical inspection of the line by the utility to confirm its integrity and ability to carry more current without adversely impacting conductor life;
- visual observation of the line sag under varying current flow to confirm model predictions;
- increasing pole height and/or retensioning of the line, if necessary, based on anticipated increase in sag, to maintain the minimum ground clearance specified in GO-95;
- installation of dynamic line rating equipment to continuously monitor conductor status in real-time to identify critical current conditions that may trigger load shifting or load shedding activities.

While the above practices are not without cost, they are typically a fraction of the cost (20 – 25%) of reconductoring. Although rerating of a transmission line is an attractive option, it is unlikely to allow for ampacity expansion exceeding 10 – 15% of the existing line rating (Wood, 2003).

No information is currently available from PG&E regarding the line ratings of the affected distribution circuits. Based on the preliminary evaluation of ampacity presented under the reconductoring option, it appears that the reconductoring would not be an option for the 15 mgd buildout case (since combined ampacity would be greater than 115%). Depending on the ability of PG&E to load shift and the physical condition of these distribution circuits, rerating may be an option for either the 5 mgd or 10 mgd case. Under a rerating option, MMWD would continue to purchase power directly from PG&E at the projected current price of \$0.135/kWh.

### 3.2 ESTIMATED COST OF RECONDUCTORING ALTERNATIVE

The cost of rerating is estimated at approximately 25% of the cost of reconductoring. It is also noteworthy that PG&E costs for rerating may be absorbed by PG&E depending on other planned

distribution upgrades in the area, and the projected revenue associated with the additional load. Potential rerating costs are summarized below for each phase. These costs do not include any necessary substation upgrades, which would need to be separately determined by PG&E. All of these costs would need to be confirmed by PG&E through a detailed large account evaluation process.

| <b>Desalination Plant Size, mgd</b> | <b>Estimated Capital Cost, \$ (literature-based)<sup>1</sup></b> | <b>Estimated Capital Cost, \$ (PG&amp;E-based)<sup>2</sup></b> | <b>Anticipated Electrical Consumption, kWh<sup>3</sup></b> | <b>Anticipated Operating Cost, \$/yr<sup>4</sup></b> |
|-------------------------------------|--|--|--|--|
| 5                                   | Possibly none – 18,750   | Possibly none – 49,000   | 22,000,000   | 770,000  |
| 10                                  | 18,750   | 49,000   | 42,000,000   | 5,670,000  |
| 15                                  | Not likely to be an option                                       | Not likely to be an option                                     | 64,000,000   | 8,640,000  |

<sup>1</sup> Capital cost is a one-time cost for rerating assuming cost is 25% of reconductoring costs (Wood, 2003) The estimated cost excludes any substation upgrade costs that may be necessary.

<sup>2</sup> PG&E estimate and is a one-time cost for transmission upgrade (i.e. once the reconductoring is completed it is assumed that it would have sufficient capacity to service all phases of the project).

<sup>3</sup> MMWD memo from Dana Roxon to Ron Thiesen, May, 2003.

<sup>4</sup> Operating cost is based on current electrical rate of \$ 0.135/kWh and anticipated electrical.

**3.3 KEY ENVIRONMENTAL CONCERNS**

There are no significant environmental concerns associated with rerating.

**3.4 IMPLEMENTATION CONSTRAINTS**

While rerating is a commercially acceptable way of expanding transmission capacity it may only be a viable option for the 5 mgd or 10 mgd development phase. Preliminary calculations indicate that a rerating in excess of 15% would be necessary for the 15 mgd case and an increased rating of this magnitude is unlikely.

**3.5 SCHEDULE IMPLICATIONS**

The process of rerating would commence with a formal study request by the MMWD account representative. We anticipate that PG&E could improve upon the schedule provided for reconductoring by approximately one month. PG&E typically requires 3 – 4 months to complete the investigation, depending on the current backlog. The results of the investigation would then be reported back to MMWD in terms of an analysis of the system impact, and estimate of the costs for the upgrade and a cost proposal for the upgrade. MMWD would likely have the option to complete the upgrade itself (or by a qualified contractor under its direction) in accordance with PG&E specifications, at a likely savings. Once a signed agreement was obtained for the work, PG&E would undertake the work and could likely complete it within 3 – 5 months. These initial estimates will need to be confirmed by MMWD’s large account manager.

**3.6 REFERENCES**

MMWD, 2003. *District Electrical Energy Use*. Memo from Ron Thiesen to Dana Roxon, May 27, 2003.

Wood, 2003. Personal communication with David Stein, URS and Dan Wood, Utility Systems.

## 4.1 TECHNOLOGY CHARACTERIZATION

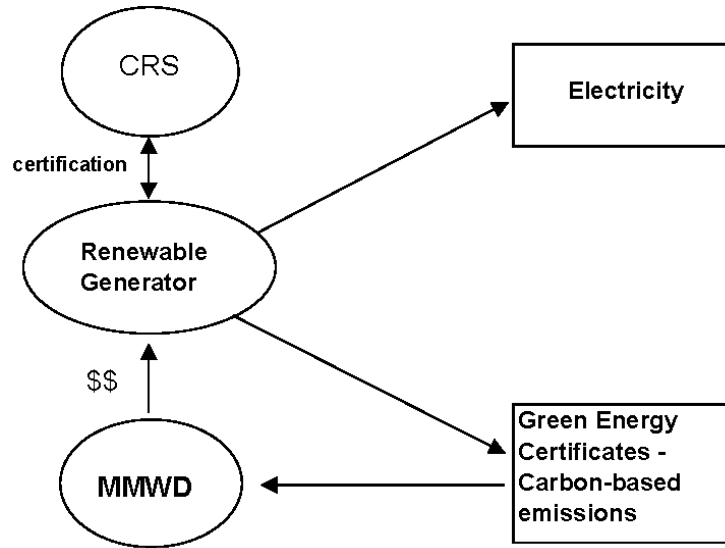
Green energy is a term that has come to be associated with a class of renewable energy alternatives including solar, wind, small or low impact hydropower, geothermal, and biomass or biogas fueled generation. California has historically led the nation in sponsorship of green or renewable energy alternatives through a variety of policy, legislative and regulatory initiatives over the last two decades. As a result of these regulatory requirements and the continued funding support made available through the California Energy Commission (CEC), there is an active green or renewable energy segment of the California electrical generation market that continues to thrive. In California, approximately 12.4% of the in-state generation mix was generated by renewable energy in 2001. Under Senate Bill (SB)1078, effective January 1, 2003, investor owned utilities are subject to a California Renewable Portfolio Standard (RPS) and are required to increase their procurement of eligible renewable energy resources by at least 1 percent per year so that 20 percent of their retail sales are procured from eligible renewable energy resources by 2017.

With the deregulation of the electricity market, California was the first state to establish a mechanism for direct purchase of green energy from independent electric service providers (ESPs). However, after the now infamous collapse of the California electricity market, the legislature directed the California Public Utilities Commission (CPUC) to eliminate the right of retail end-users to purchase power from direct access ESPs after September 20, 2001 (CPUC Decision D.01-09-060). As a result, there is today (despite the RPS) no active mechanism for MMWD to contract directly and exclusively for green energy in California that can be wheeled and delivered through an existing transmission connection (PG&E, 2003). There is, however, proposed legislation (SB 888 – Dunn) that could reinstate direct access ESPs. Unless the direct access restriction is eliminated, purchase of green energy is instead only available to MMWD in one of the following ways:

- Continued purchase of PG&E electricity, recognizing that the California generation mix is approximately 12 % green (with increasing percentages annually in conformance with SB 1078 requirements)
- Purchase of tradable renewable certificates

The purchase of tradable renewable certificates (Green-E Certified Energy) is a program that is administered by the Center for Resource Solutions (CRS). CRS is an independent non-profit center that certifies each Green-E provider in terms of its green energy content, certifies the accuracy and appropriateness of any marketing claims it makes to potential buyers on green energy content, and independently audits its ability to meet strict “green” environmental standards. Tradable renewable energy certificates are used to financially support green energy provider operations and authenticate that the green energy has been generated somewhere in the United States, but not necessarily in California. In essence, the Green-E option can be viewed as a voluntary green energy surcharge, which would support renewable energy generation elsewhere and allow MMWD to take credit for the environmental benefits of any Green-E electricity that it purchased. A basic schematic of the process of purchasing green energy is shown in Figure 1.

Figure 1 - Schematic of Green Energy



**4.2 ESTIMATED COST OF GREEN ELECTRICITY**

There are several CRS-certified suppliers of green electricity, with current pricing in the range of \$ 0.0177/kilowatt-hour (kWh) to \$ 0.250/kWh. There is no capital cost associated with the purchase of green energy. However this option would require that MMWD continue purchasing PG&E electricity for existing operations as well as the proposed desalination plant. A transmission line upgrade or rerate would therefore be required as described in Sections 2 and 3 above. Using the average of the above cost range, the annual cost to purchase green energy for the desalination project is summarized in the table below.

| Desalination Plant Size, mgd | Estimated Annual Electricity Requirement, kwh | Capital Cost of Transmission Upgrade, \$ | Annual Cost of Green Energy Credits, \$ | Annual operating cost (electricity + green energy credits), \$ |
|------------------------------|---|--|---|--|
| 5                            | 22,000,000                                    | As reported for reconductoring base case | \$ 469,700                              | \$ 3,439,700   |
| 10                           | 42,000,000                                    | As reported for reconductoring base case | \$ 896,700                              | \$ 6,566,700   |
| 15                           | 64,000,000                                    | As reported for reconductoring base case | \$ 1,366,400                            | \$ 10,006,400  |

**4.3 KEY ENVIRONMENTAL CONCERNS**

The purchase of green energy has a distinct environmental benefit in that both carbon-based (greenhouse gas [GHG] emissions) and criteria air pollutant emissions are reduced as a result of the green energy support. GHG reductions have global benefits in reducing the potential impact to global warming induced by GHG emissions and the location of the potential GHG reductions are arguably not particularly relevant. The reductions in local/regional criteria air pollutant

emissions that accrue from support of green energy would accrue to the location where the renewable energy is generated and would not provide a direct benefit in the air shed shared by MMWD customers.

#### **4.4 IMPLEMENTATION CONSTRAINTS**

There are no apparent implementation constraints to the purchase of green energy. There are multiple ways that MMWD could implement this option, including for example:

- Direct payment to a green-E provider from MMWD operating funds
- Creation of a “self-funded” green-E account by offering customers the ability to select green-E on their MMWD bill for a voluntary surcharge

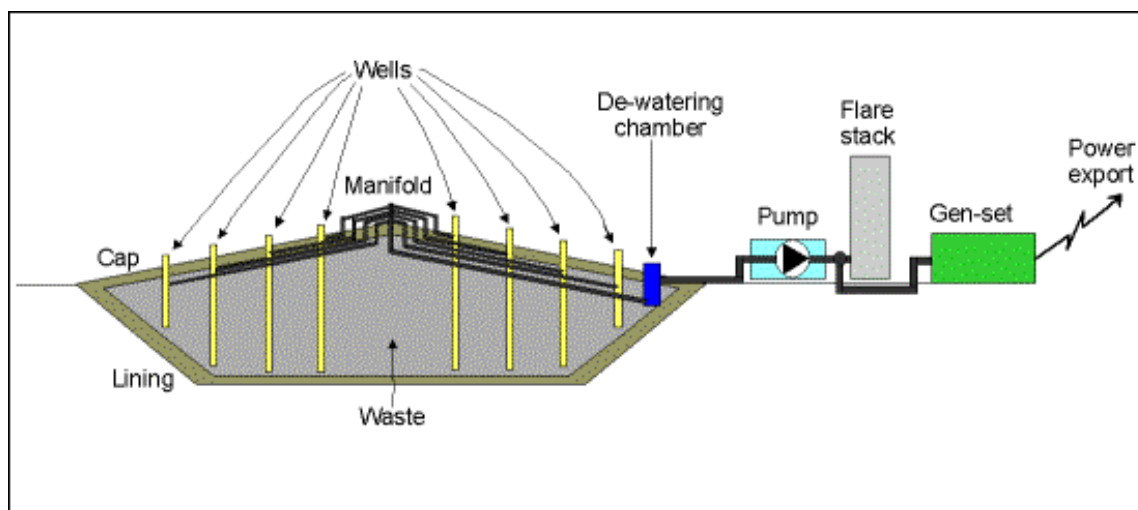
#### **4.5 SCHEDULE IMPLICATIONS**

There are no schedule constraints to the purchase of green energy, which can commence immediately if so desired by the MMWD.

#### **4.6 REFERENCES**

CRS, 2003. Telephone conversation with Jan Hamrin, Director, CRS and David Stein, URS; June 2003.

PG&E, 2003. Customer Choice. [http://www.pge.com/006\\_news/006f\\_cust\\_choice.shtml](http://www.pge.com/006_news/006f_cust_choice.shtml), June 2003.



## 5.1 TECHNOLOGY CHARACTERIZATION

Landfill gas (LFG), which is created as waste in a landfill decomposes, is comprised primarily of methane (35–58 percent) and carbon dioxide (40–55 percent). Lesser constituents include water vapor (0–10 percent), nitrogen (0–15 percent) and oxygen (0–2.5 percent). Other compounds are found in trace quantities including Hydrogen sulfide (1–700 ppm) and nonmethane organic compounds (200–14,000 ppm). Methane is considered a particularly potent greenhouse gas, having nearly 21 times the global warming effects of carbon dioxide, according to the Intergovernmental Panel on Climate Change (IPCC). Methane can also be highly explosive, leading to landfill fires. Rather than allowing landfill gas to escape into the air or flaring it with potentially adverse environmental consequences, the gas can serve as an efficient energy source that can be captured, converted, and used to produce electricity.

Methane gas can be recovered by a series of wells that are drilled into the landfill. The wells are interconnected by a common collection system that transports the gas to a compression facility. There, the gas is compressed, dried, and filtered before being sent through turbines or engines to produce electricity. The electricity can be transported to the plant site using existing PG&E transmission lines. Alternatively, because the landfill sites are within ten miles of the proposed plant site, landfill gas can be delivered through pipelines directly to the desalination facility.

There are five power generation technology choices using landfill gas: reciprocating engines, gas turbines, steam boilers, microturbines, and fuel cells. A review of each of these technology options indicates that reciprocating engines have the greatest efficiency in producing power per unit of fuel. Given the annual average electricity requirement of 2.5 – 7.3 MW for the proposed desalination facility (Roxon, 2003), reciprocating engines would be the most appropriate technology choice. With 32 operating facilities and a combined generation capacity of 112 MW, they are also the most widely installed and readily available systems in California (CEC, 2002). While gas turbines have lower operations and maintenance (O&M) costs and lower air emissions on average, they produce only 2/3 of the electricity produced by reciprocating engines and have a higher capital cost per unit of fuel. According to vendors and the CEC, steam boilers and microturbines do not have the capacity to produce the requisite power and fuel cells are still at a pilot stage for landfill gas applications.

The two nearest landfill sites to MMWD's proposed alternative site for the desalination facility are the Redwood Landfill in Novato and the San Quentin Disposal Site in San Rafael. The amount of gas that can be recovered from either landfill would vary substantially depending on factors such as the amount and type of waste, moisture content of the landfill, amount of oxygen present, landfill size and characteristics, and temperature. Certain chemical reactions and the evaporation of some chemicals may also produce usable gas. It may take several years to produce landfill gas at a sufficient rate to fuel a generator and the rate may only last for a few years. The period over which landfill gas is produced can be over 50 years. However, usable gas production rates typically last 10–15 years (CEC 2002). It is difficult to size a landfill gas electricity generator because of variations in the landfill gas production rate. Underestimation of landfill gas production results in unused energy that must be flared. Overestimation can result in the installation of generation equipment that is unable to run at rated capacity.

According to Marin County's Environmental Health Services Office, the San Quentin Disposal Site was closed in 1987 with 841,000 tons of refuse at the landfill. Despite the high tonnage at the site, it is unlikely that the waste could generate substantial energy because it consists largely of brush clippings, asphalt, wood, and concrete – not municipal solid waste, which has a much higher waste-to-energy recovery ratio. Additionally, because 16 years have passed since the landfill's closure, it is unlikely that substantial usable energy can be obtained.

The Integrated Waste Management Board of California reported that, in 2000, the Redwood Landfill in Marin County had disposal averages of 96,000 tons of solid waste per quarter. The CEC estimates that in the same year the Redwood Landfill had 4 million tons of Municipal Solid Waste (MSW) in place. The landfill is expected to remain active through 2039 Waste Management, Inc. (CEC 2002) and currently has plans to install a 0.96 MW engine at the site.

The Redwood Landfill could be a potential source of fuel for the proposed desalination plant, but it is unlikely that it can produce sufficient electricity for a 5–15 MGD desalination plant. Based on WMI's plans, only 1 MW of generating capacity is expected to be available. This would not produce sufficient electricity to supply a 5–15 mgd desalination. Further investigation will be required to confirm whether additional electricity generation may be possible from this site, but it would appear, based on WMI's plans, that there is only sufficient capacity for a portion of the needs of a 5 mgd plant.

## **5.2 ESTIMATED COST FOR LANDFILL GAS TO ENERGY ALTERNATIVE**

The capital cost for a landfill gas-to-energy project is dependent on site characteristics, the conversion technology used, and the extent of the collection systems already in place. Generally speaking, there is no cost for the landfill gas itself. There is, however, a capital cost associated with installation of extraction wells, compressors, and gas cleaning equipment. The capital costs for a reciprocating application average \$2,000/kw installed, including the cost of the extraction system (CEC 2000).

Capital costs, estimated in Table 2.2 below, may be offset by financial incentives offered through the CEC and PG&E. While some grant programs offered by the CEC may not be available to MMWD, California offers municipalities a low interest loan of \$2.5 million at an interest rate of 3.95 percent over 15 years. PG&E also offers a grant of up to \$1.5 million, not to exceed 50 percent of the total cost. These packages can be combined or used exclusively to recover some of the costs associated with a landfill gas-to-energy system.

**Table 2.2**  
**Cost Estimates for Landfill Gas-to-Energy**

| Desalination Plant Size (MGD) | Estimated Capital Cost <sup>1</sup> | Anticipated Electrical Consumption(kWh) <sup>2</sup> | Anticipated Annual Operating Cost <sup>3</sup> |
|-------------------------------|-------------------------------------|--|--|
| 5                             | \$5,000,000                         | 22,000,000   | \$330,000                                      |
| 10                            | \$9,600,000                         | 42,000,000   | \$630,000                                      |
| 15                            | \$14,600,000                        | 64,000,000   | \$960,000                                      |

<sup>1</sup> Capital cost estimates based on rate of \$2,000 / kW. This rate can vary widely depending on the technology used to convert landfill gas to electricity. The estimate provided here is based on an average rate using reciprocating engine technology, which is likely to be most suitable for MMWD's application. (CEC 2002)

<sup>2</sup> MMWD memo from Dana Roxon to Ron Thiesen, May, 2003.

<sup>3</sup> Operating cost is based on estimated rate of \$ 0.015/ kWh.

### 5.3 KEY ENVIRONMENTAL CONCERNS

Methane emissions from landfills are potential contributors to global warming. They may also lead to groundwater contamination and produce strong odors. Although the majority of landfill gas emissions are quickly diluted by the atmosphere, in confined spaces there is a risk of asphyxiation and/or toxic effects if landfill gas is present at high concentrations.

Using the gas to generate electricity reduces the adverse impacts of odors and other hazards associated with landfill gas emissions, and helps prevent methane from migrating into the atmosphere. However, the process of landfill gas recovering and processing may have its own impacts to air quality and water quality. Emissions such as CO<sub>2</sub>, CO, NO<sub>x</sub>, SO<sub>x</sub> and other components may have adverse air quality effects. In addition, NO<sub>x</sub> and CO emissions from reciprocating engines tend to be higher than for other prime movers (such as boilers, gas turbines, or fuel cells). Condensate produced during landfill gas recovery may pose a water quality problem, and most California state and regional environmental policies prohibit the recycling of condensate within landfills.

### 5.4 IMPLEMENTATION CONSTRAINTS

Reciprocating engine technology for landfill gas-to-energy applications is commercially available. Landfill gas recovery systems are modular, providing some flexibility in size and capacity. The average size of a 1.3 MW module is 40 x 8 feet. Along with the cooling tower and other components, the system would have a total space requirement of about ¼ acre for a 2.5 MW capacity (sufficient for a 5 mgd facility). Total space requirements for full build out (assuming a 15 MGD desalination plant) would still be less than one acre.

Further study is needed to determine the amount of energy that could be recovered over time from the Redwood Landfill. At the present time it does not appear that there is sufficient landfill gas production capacity to support the project.

**5.5 SCHEDULE IMPLICATIONS**

As they are pre-manufactured systems, they can also be installed within six months of an order. This would include the paving and grading at the site. In addition to the system installation, gas extraction wells would have to be set up and negotiations held with PG&E to use their transmission lines.

**5.6 REFERENCES**

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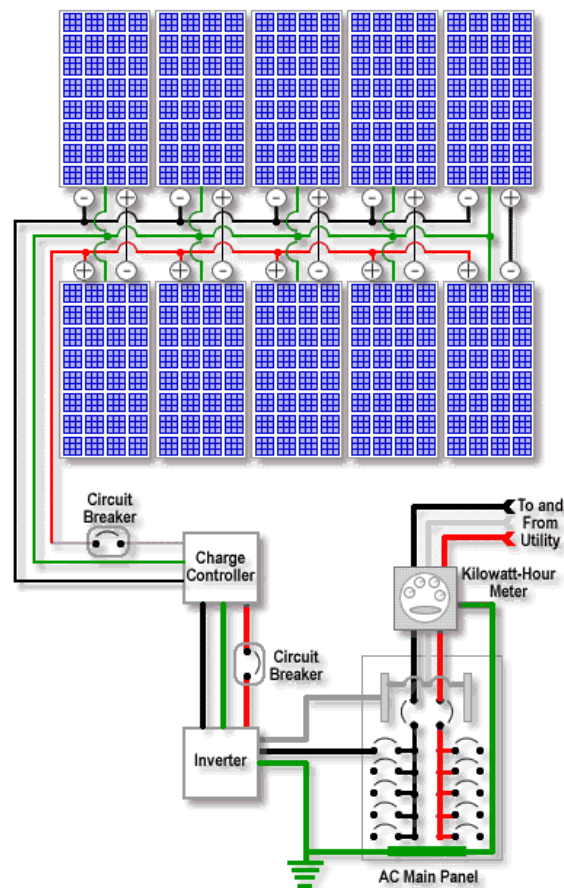


Diagram adopted from Next Steps Energy Systems:  
<http://64.226.184.153/html/solarelectriccomponents.htm>

## 6.1 TECHNOLOGY CHARACTERIZATION

Photovoltaics (PVs) are silicon cells that convert sunlight directly to electricity. When light energy strikes the PV cell (or solar cell), photons are absorbed and electrons are released. By attaching electrical conductors to the positive and negative sides forming an electrical circuit, the electrons are captured in the form of an electric current. This electricity is then used to power a load. Because PVs use solar radiation as the fuel source, they cannot generate electricity when light conditions are poor (i.e. at night and in heavy fog).

Given Marin County's general light conditions, a PV system can be expected to generate electricity for 4-6 hours of the day, on average. In that time, the system can be designed to generate enough power to serve the plant's entire daily demand. However, as the power demand is spread out over time, surplus power produced by the PV system would either have to be stored or transmitted through the grid. MMWD could exchange surplus power for power through the grid during parts of the day when the PV system is not generating electricity. As storage costs and space requirements for storage would be relatively high, this survey assumes that power would be exchanged with PG&E to meet the plant's electricity demand.

Solar energy currently provides the smallest percentage of California's non-hydro renewable electricity; however, vendors and researchers alike suggest that it exhibits the fastest growth of

any power technology. Although the current installed base of PV in California is only 10 MW, projects in the planning stages indicate that this capacity is expected to be doubled in the near-term. By 2020, according to the Renewable Energy Policy Project, California could install between 700 MW and 1300 MW of PV. Most of the projected growth will continue to be in the off-grid market.

PV is the renewable energy technology with the lowest operation and maintenance requirements and is especially suited for small-scale applications in remote areas where conventional energy sources are expensive to obtain and space is not a constraining factor.

**6.2 ANTICIPATED COST**

Although the cost of PV systems are generally high, they depend on factors such as the system’s configuration, equipment options, and labor costs (CEC 2003) (approximately \$8/watt installed). As a result, costs can vary greatly. The increase in efficiency also continues to significantly reduce costs per unit of energy produced. The estimates provided below are based on literature reviewed and discussions with a vendor.

It is noteworthy that significant advances are anticipated in PV systems in the next few years that could reduce installed cost to \$1–3/watt (CRS 2003). At lower installed cost, PV systems may become more economically attractive.

| <b>Desalination Plant Size (MGD)</b> | <b>Estimated Capital Cost<sup>1</sup></b> | <b>Anticipated Electrical Consumption(kWh)<sup>2</sup></b> | <b>Anticipated Annual Operating Cost<sup>3</sup></b> |
|--------------------------------------|---|--|--|
| 5                                    | \$80,000,000                              | 22,000,000   | N/A  |
| 10                                   | \$153,600,000                             | 42,000,000   | N/A  |
| 15                                   | \$233,600,000                             | 64,000,000   | N/A  |

<sup>1</sup> Capital cost estimates based on rate of \$8 / W. This rate is based on a conservative estimate derived from conversations with The Perfect Power Network and a review of the CEC’s Handbook on Buying PV Electric Systems. Costs include an overcapacity factor of 4 to allow for exchange of peak power for nonpeak power.

<sup>2</sup> MMWD memo from Dana Roxon to Ron Thiesen, May, 2003.

<sup>3</sup> Operating cost will consist primarily of inspections of electrical switching systems. Systems will last 20-30 years, rendering any replacement unlikely during that time. Therefore, while operating costs will depend on final design and are difficult to estimate at a pre-design stage, it can be assumed that they will be marginal.

**6.3 KEY ENVIRONMENTAL ISSUES**

PV is seen to be generally of benign environmental impact, generating no noise or chemical pollutants during use.

**6.4 POTENTIAL CONSTRAINTS TO IMPLEMENTATION**

Solar energy-powered plants are typically of low to medium size due to large area requirements. Area estimates provided by The Perfect Power Network indicate that would be required to generate an average of 7.3 MW (the power requirement for a 15-mgd facility). This equates to approximately 2.6 square feet of PV area for every 100 watts generated. By contrast, the CEC estimates 8–30 square feet of PV area for every 100 watts installed. Using the CEC’s minimum estimates, an area of 13.4 acres would be needed to generate 2.3 MW. These space requirements need to be coupled with the need to install a factor of 4 overcapacity to allow for the exchange of peak solar power that is only available for approximately 6 hours, for offpeak power that would

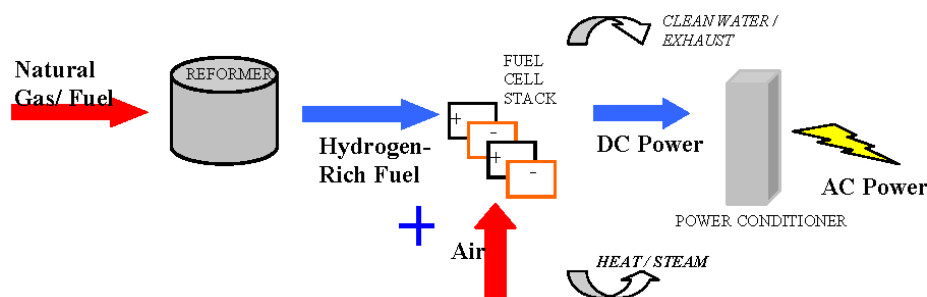
be purchased back for the desalination plant 24-hour-day operation. When this factor is considered, the space requirement for PV solar for a 5 mgd, 10 mgd, and 15 mgd desalination plant would be approximately 6–18 acres, 12–36 acres, and 24–72 acres, respectively (depending on whether vendor or CEC space estimates are used). While this space can be a combination of either open or rooftop space, the footprint needed to accommodate a full solar powered desalination plant may be greater than the site can accommodate.

## **6.5 SCHEDULE IMPLICATIONS**

PV panels are modular and relatively simple to install. The panels are tied together using interconnect cables and operated by a control panel that can connect to the grid. Including testing, the system would take approximately 4 weeks to install.

## **6.6 REFERENCES**

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## 7.1 TECHNOLOGY CHARACTERIZATION

Fuel cells use electrochemical energy to combine hydrogen and oxygen into water, producing electricity and heat in the process. Typically, a hydrocarbon fuel or alcohol fuel (natural gas, methanol, propane, or gasoline) is passed through a reformer where sulfur is removed and hydrogen is produced. Renewable sources such as landfill gas, solar energy, and wind can also be used to produce hydrogen. If a renewable energy source is used as the main source of hydrogen, a fuel cell can be considered a renewable energy source. However, because natural gas would be easily accessible at the MMWD desalination plant through the existing grid (whereas other sources would require additional infrastructure), this survey assumes the use of natural gas as the primary source for fuel cell electricity generation.

Once the hydrogen is produced, it is sent to the anode (positively charged electrode) and oxygen from the air is sent to the cathode (negatively charged electrode). The electrons generated at the anode pass through an external circuit to the cathode, generating electricity. At the cathode, the hydrogen ion, electron, and oxygen react to form water. Several such cells are stacked in a series (fuel cell stack) to obtain direct current (DC) power output. As a final step, a power conditioner converts the variable DC electricity into steady AC output for consumption.

Fuel cells have an efficiency of 40-60 percent. They use less fuel per unit of electricity produced and have lower greenhouse gas emissions than conventional systems for producing electricity with fossil fuels. Other advantages that make this technology attractive include modularity, fuel flexibility, and high power density. However, it is important to note that fuel cell systems are still in the early stages of development and many systems are not fully commercial on a large scale.

There are several different types of fuel cells, each using a different chemistry. Fuel cells are usually classified by the type of electrolyte they use. The three classifications of fuel cells considered in this survey operate at different temperatures. The temperatures of the fuel cells correlate with their power and efficiency. Lower temperature fuel cells such as polymer membrane fuel cells (PEMs) are appropriate for small-scale applications like powering a laptop computer. Medium-temperature fuel cells such as the phosphoric acid fuel cell (PAFC) are manufactured in 250 kW units. The capital cost of a PAFC unit is approximately \$800,000 (per 250 kW). The high-temperature molten carbonate fuel cell (MCFC), which can generate for 1 MW to over 10 MW, and solid oxide fuel cell (SOFC), which can generate up to 1 MW, may be most appropriately considered for the proposed MMWD desalination plant. Of the two, MCFC fuel cells are also best suited for large stationary power generators. They operate at 1,112 F (600 C), so they also generate steam that can be used to generate more power. They have a lower operating temperature than the SOFC, which means they can be turned on and off more quickly. The design is also less expensive.

## 7.2 ANTICIPATED COST

Based on discussions with the CEC, as a water utility, it is not likely that MMWD would qualify for consumer rebates through the Emerging Renewables Program or the state's Renewable Energy Buy-Down Program. Other programs for which MMWD may qualify can be reviewed through the Database of State Incentives for Renewable Energy (DSIRE).

Cost estimates for fuel cell systems are based on discussions with vendors and CEC's literature on the subject. While several factors would determine the price cost of the actual system, the costs represented here are based on conservative estimates of modular MCFC units.

Operating costs associated with fuel cell systems are largely in the form of replacement costs. A fuel cell system has to be replaced after the first three years and then every five years after that. Replacement costs may represent up to 30 percent of the total capital cost. Replacement fuel cells tend to be more efficient than the original cells; therefore, a system that had an initial capacity of 2 MW could increase its capacity to almost 3 MW after an initial replacement. In the estimate provided below, replacement costs have been spread out on an annual basis and factored in as the largest component of the anticipated operating cost. According to industry estimates, on an annual basis, replacement costs run approximately 13 percent of the capital costs.

**Table 3.2**  
**Estimated Cost of Installing and Operating Fuel Cell Systems**

| Desalination Plant Size (MGD) | Estimated Capital Cost <sup>1</sup> | Anticipated Electrical Consumption(kWh) <sup>2</sup> | Anticipated Annual Operating Cost <sup>3</sup> |
|-------------------------------|-------------------------------------|--|--|
| 5                             | \$12,500,000                        | 22,000,000   | \$1,625,000                                    |
| 10                            | \$24,000,000                        | 42,000,000   | \$3,120,000                                    |
| 15                            | \$36,500,000                        | 64,000,000   | \$4,745,000                                    |

<sup>1</sup> Capital cost estimates based on rate of \$5 / W. This rate is based on an estimate for a MCFC module provided by Fuel Cell Energy, a Connecticut-based vendor. The estimate was confirmed by Schatz Energy Research Center.

<sup>2</sup> MMWD memo from Dana Roxon to Ron Thiesen, May, 2003.

<sup>3</sup> Operating cost is based on estimated rate of 13% of capital cost (including periodic replacement).

## 7.3 KEY ENVIRONMENTAL ISSUES

Although nearly three times cleaner than comparable electricity levels generated from a coal-fired power plant, fuel cell systems with reformed hydrogen will still emit three times the CO<sub>2</sub> than those that get their hydrogen from sustainable sources such as solar energy.

Since the technology development is still in its infancy, there continues to be debate about the potential adverse impacts of fuel cell systems. In a June 13, 2003 article of *Science Magazine* entitled "Environmental Impacts of a Hydrogen Fuel Economy", researchers from the California Institute of Technology raised the possibility that if hydrogen fuel replaced fossil fuels entirely it could be expected that 10 percent to 20 percent of the hydrogen would leak from pipelines, storage facilities, processing plants and fuel cells in cars and at power plants. This could cause further destruction of the ozone layer.

## 7.4 POTENTIAL CONSTRAINTS TO IMPLEMENTATION

Fuel cell systems are still in the early stages of development. As such, there are technical risks, particularly for large-scale applications such as MMWD's proposed desalination plant. Vendors

able to supply and service such large-scale systems are also limited. In addition, costs associated with the technology continue to be high, particularly if government-based incentives are not available. As the technology continues to be modified and efficiencies improve, systems purchased in the near-term may become outdated very quickly.

## **7.5 SCHEDULE IMPLICATIONS**

As fuel cell systems are typically modular, they are pre-manufactured and simple to install. A 2 MW system produced by Fuel Cell Energy, as an example, would come as a complete in a 48' x 59' x 27' trailer. Although they can take almost a year to manufacture, they can be fully installed within 4-6 weeks.

## **7.6 REFERENCES**

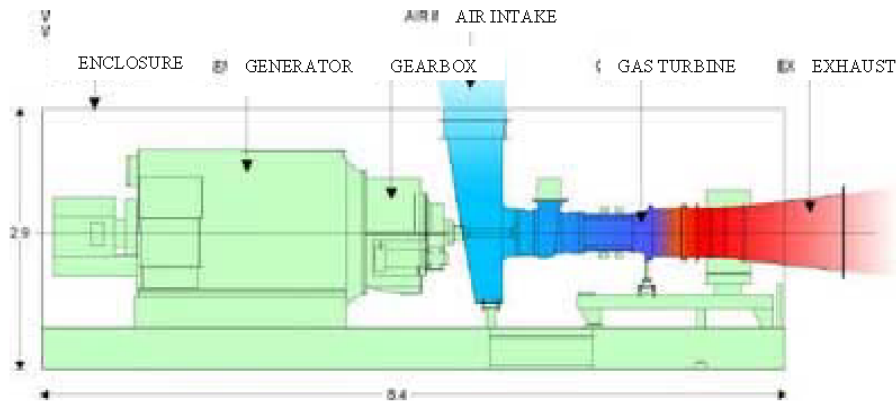
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## 8.1 TECHNOLOGY CHARACTERIZATION

Combustion turbines are a class of electricity generation devices that use natural gas to produce high-temperature, high-pressure gas to induce shaft rotation by impingement of the gas on a series of specially designed blades.

The efficiency of electric power generation for combustion turbine systems, operating in a simple-cycle mode (i.e., without external use of heat in the turbine exhaust), ranges from 21 to 40 percent. Combustion turbines produce high quality heat that can be used to generate steam and hot water for other applications, including heating and cooling (using absorption chillers). Efficiencies in excess of 60 percent are possible when the turbine exhaust heat is recovered in a heat recovery steam generator to make steam that can either be used for mechanical/process needs or for generation of additional power in a steam turbine. The former adaptation is referred to as cogeneration and the later as combined cycle. Cogeneration and combined cycle applications are most common for base loaded systems that would operate steadily throughout the day.

Utilization of thermal energy in the combustion turbine exhaust significantly enhances the efficiency of energy utilization. Maintenance costs per unit of power output for combustion turbines are among the lowest of all power generating technologies.

Power output rating of all combustion turbines is based on inlet temperature of 59°F. Output capacity of these turbines decreases with increase in ambient air temperature. Therefore, in hot weather climates or on hot days, cooling of turbine inlet air has been found to be cost effective for many power plants for boosting power output.

Two types of combustion turbines are commercially available:

- Industrial turbines - can provide 1 MW to more 100 MW of electric power; energy efficiency ranges from 25 to 40 percent
- Micro turbines – capacities of less than 1 MW; these turbines can use natural gas, propane, and gases produced from landfills, sewage treatment facilities, and animal waste processing plants as primary fuel.

## 8.2 ANTICIPATED COST

Combustion turbines installations vary in cost depending on whether the installation is a simple or combined cycle and the size and complexity of the installation. As a general rule, gas turbines installation costs follow economy of scale principles with smaller units being more expensive on a \$/kW basis than larger units. For very large power plants (>100 MW), it may be possible to install a facility with a total cost in the range of \$ 500 - \$1,000/kW. For smaller installations, such as the one envisioned for the MMWD project, an installed cost in the range of \$1,200 - \$1,800/kW is typical. For purposes of estimation, a midrange value, \$1,500/kW installed, has been used. Operating costs associated with gas turbines are primarily attributed to the costs of fuel. Natural gas has been valued at \$5.00/MMBtu. A fuel efficiency of 7,500 Btu/kWh has also been assumed. Finally, nonfuel-related O&M costs have been estimated at \$17/kW-yr (CEC 2003).

| Desalination Plant Size (MGD) | Estimated Capital Cost <sup>1</sup> | Anticipated Electrical Consumption(kWh) <sup>2</sup> | Anticipated Annual Operating Cost <sup>3</sup> |
|-------------------------------|-------------------------------------|--|--|
| 5                             | \$4,500,000                         | 22,000,000   | \$933,000                                      |
| 10                            | \$9,000,000                         | 42,000,000   | \$1,870,000                                    |
| 15                            | \$13,500,000                        | 64,000,000   | \$2,800,000                                    |

1 Estimated based on a installed cost of \$1,800/kW

2 MMWD memo from Dana Roxon to Ron Thiesen, May 2003

3 Based on heat rate of 7,500 Btu/kWh, natural gas at \$5.00/MMGtu and nonfuel )&M at \$17/kW-yr (CEC 2003)

## 8.3 KEY ENVIRONMENTAL CONCERNS

The major environmental issues associated with the use of conventional gas turbine technology are air emissions (NO<sub>x</sub>, CO, VOC, PM<sub>10</sub> and trace amounts of SO<sub>2</sub>), availability of emission reduction credits that may be required by the Bay Area Air Quality Management District, ambient noise impacts, and potential risk of upset associated with the handling of aqueous ammonia used for NO<sub>x</sub> control. It is also important that the site be appropriately zoned for power generation.

## 8.4 IMPLEMENTATION CONSTRAINTS

In order to implement a gas turbine based cogeneration system, there must be an adequate supply of high pressure natural gas. In circumstances where there is inadequate line pressure, it may be necessary to include a gas compressor in the project design. This will add capital cost to the system. For a cogeneration or combined cycle system there must also be an adequate supply of raw water for operation of the steam cycle. A small cogeneration system of the size under consideration would require an approximate 2 to 3 acre footprint.

## 8.5 SCHEDULE IMPLICATIONS

The delivery time on combustion turbines is approximately 6 months from placement of order. This delivery time can usually be accommodated within the constraints of a normal

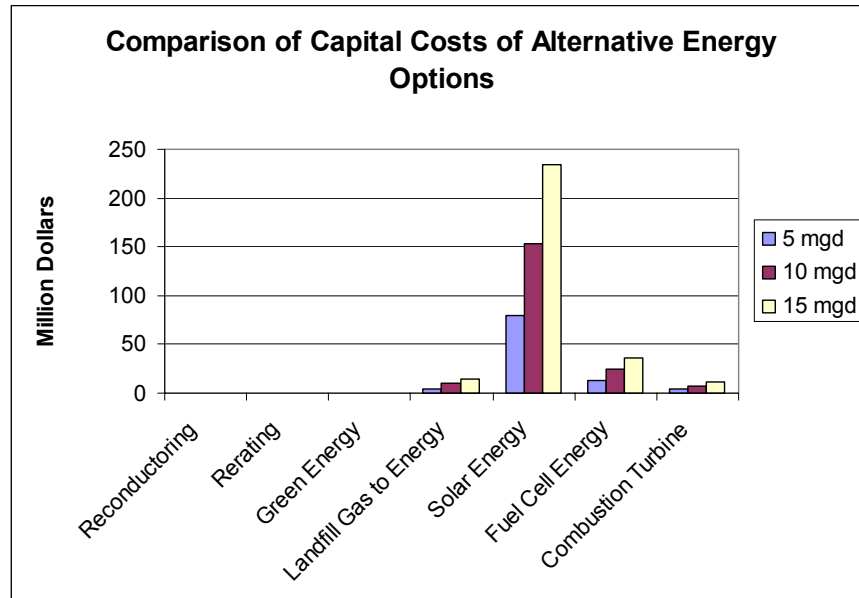
construction schedule. A typical cogeneration system can be constructed in a 9 to 12 month period.

## **8.6 REFERENCES**

MMWD, 2003. Memo from Dana Roxon to Ron Thiesen, May 2003.

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A number of alternative energy technologies have been evaluated with respect to both capital and operating costs. The following figures provide a graphic comparison of these costs on an installed cost, annual operating cost and net present cost basis.



As can be seen from the above figure, the installed cost of reconductoring, rerating and green energy are substantially lower than the other alternatives. Landfill gas to energy and combustion turbine-based energy have comparable costs. It is important to note that a landfill gas to energy project may not be viable, as discussed in Section 5, because of a lack of sufficient landfill gas production. Fuel cell energy is available at a premium relative to the other technologies and solar energy is the most expensive from a capital cost standpoint. Based strictly on capital cost considerations, rerating is the preferred option followed by reconductoring and green energy.

In the next figure, we compare equivalent annual operating costs of the various technologies. It is apparent from the figure that the transmission options represent the most expensive options from an operating cost standpoint. The least expensive operating cost is associated with solar energy.

In the final figure, we compare the net present value (NPV) of capital and operating costs assuming a 20-year project life and an assumed prevailing interest rate of 8%. When placed on an NPV basis, the combustion turbine-based energy and landfill gas to energy options appear most attractive financially. As we have previously noted, it is unlikely that a sufficient quantity of landfill gas can be produced at either of the local landfills to meet the needs of the proposed desalination plant. Solar energy is the most expensive technology. Fuel cell energy appears to be approximately on par with reconductoring in terms of NPV.

