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RENEWABLE DISTRIBUTED GENERATION ASSESSMENT: SAN FRANCISCO PUBLIC UTILITIES COMMISSION/ HETCH HETCHY CASE STUDY

PIER FINAL PROJECT REPORT

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PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), annually awarded up to $62 million through the Year 2001 to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy-Related Environmental Research
- Environmentally-Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Energy Systems Integration

What follows is case study 4 of 4 for the Distributed Generation Assessment project, contract 500-01-042, conducted jointly by Energy and Environmental Economics, Inc., and Electrotek Concepts, Inc. The report is entitled Renewable Distributed Generation Assessment: San Francisco Public Utilities Commission/Hetch Hetchy Case Study. This project contributes to the Renewable Energy Technologies program.

For more information on the PIER Program, please visit the Energy Commission's Web site http://www.energy.ca.gov/pier/reports.html or contact the Energy Commission's Publications Unit at (916)-654-4628.

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EXECUTIVE SUMMARY

Introduction

In an effort to contribute to the baseline knowledge of distributed generation value, this case study reports the methodology and results of the combined economic and engineering analysis performed by Energy and Environmental Economics, Inc. (E3) and Electrotek Concepts® (ETEK) under a California Energy Commission (CEC) PIER program-funded contract, to which the San Francisco PUC / Hetch Hetchy Water & Power (SFPUC) acts as co-administrator. The aim of this research project is to develop a methodology for evaluating the potential renewable distributed generation (RDG) applications within the municipal utility planning process. The resulting methodology from this research will be integrated with nine other related research projects occurring in parallel to this RDG Assessment project to further the greater goals of the CEC PIER program. Figure 1 maps how this RDG Assessment Project relates to the other research areas under this program. The SFPUC case study is one of four case studies under the project.

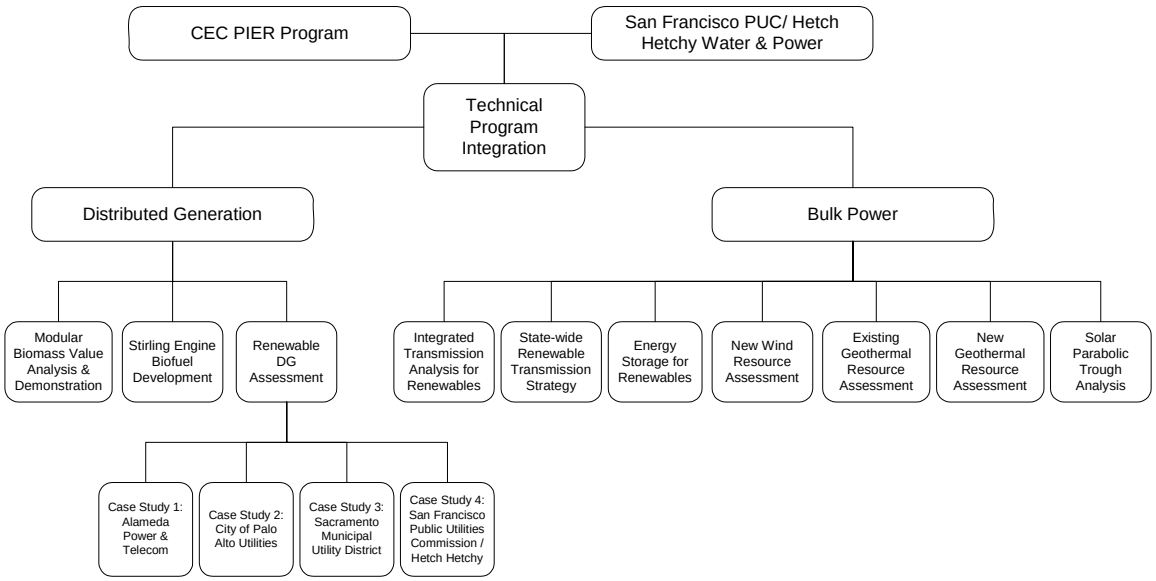

Figure 1: CEC PIER Program Research Project Structure

This case study describes the analytical process and associated results for the San Francisco Public Utilities Commission/ Hetch Hetchy Water and Power (SFPUC) distribution system. The analysis results for the remaining three municipal utilities have been provided as separate case study reports for Alameda Power and Telecom (Alameda P&T), City of Palo Alto Utilities (CPAU), and Sacramento Municipal Utilities District (SMUD).

Purpose

Numerous detailed screening studies for large transmission and distribution systems have identified several elements of value that distributed generation can provide. These include capital deferral, reduced losses, reduced operations and maintenance (O&M) costs, and risk reduction. These elements focus on cost reduction to the wires company or an integrated utility. Although it has been postulated that distributed renewable generation can provide enhanced reliability, very little in the way of quantitative analysis has been completed to include the reliability impact in DG evaluation. This research builds upon this body of work and is focused on the utility's internal planning processes.

As such, the purpose of this Renewable Distributed Generation Assessment project is to develop a sound and replicable methodology for evaluating RDG within a utility planning process. The methodology developed jointly by E3 and ETEK was applied in four municipal utility case studies throughout Northern California with the goal of facilitating the installation of cost-effective RDG systems in California.

The core contributions of this research include the following:

- Analysis of the local system impacts and benefits that accrue directly to a municipal UDC in a localized network
- Expansion of the evaluation methodology to evaluate the impacts on local system reliability, including value to both the customers and the UDC
- Incorporation of uncertainty for elements of RDG project value such as local load growth, wholesale energy prices, and capital costs for equipment

Project Objective

The overall objective is to accelerate the deployment of renewable distributed generation by fully accounting for all benefits. The specific objectives of the project are to (1) identify the best locations for distributed renewable generation (DG) in a local Utility Distribution Company (UDC) system, (2) include reliability impacts in the analysis, and (3) assess the impact of load growth and generator performance uncertainty on the results.

The key measure of success of this project is establishing an understanding of the merits of distributed renewable generation in distribution systems in general, embodied in the comprehensive application to four example distribution systems. Successful completion of this research will result in reduced overall system costs, enhanced local reliability, and increased resource diversity. The key anticipated outcome is an established and verified methodology with readily accessible tools for rapid assessment of distributed renewable technologies that can be applied to any distribution network.

Results

The results of the SFPUC RDG Assessment not only represent a successful application of the RDG Assessment methodology but also contribute to the body of research and on-the-ground testing that the SFPUC is leading to plan for the "utility of the future". For example, one SFPUC goal is to provide an efficient and sustainable energy supply in the form of intelligent- or micro-grids and this case study is an important step toward reaching this goal.

Highlights of the assessment results provided in this report include:

- In some cases, RDG is a cost-effective solution at the Hunters Point Naval Shipyard
- The most economically favorable RDG technologies at the HPNS are:
    - 800 kW biogas-fueled Caterpillar 3516 LE with CHP
    - 3 MW biogas-fueled Caterpillar G3616 LE with CHP
- Voltage changes from RDG switching on/off are within system tolerance boundaries.
- If RDG is used in lieu of line upgrades in Phases 2 and 3, it will need to be accompanied by a sophisticated energy management system to manage the voltage regulation and keep the loading on the incoming line within limits.
- Solar PV can reduce peak load but has a relatively low coincidence factor during early fall and winter evening peaks.
- Line losses are minimal because the distribution system is relatively compact.

Conclusion and Recommendations

This analysis provides a comprehensive evaluation of the potential value of RDG resources at the HPNS. A robust methodology was used to conduct the evaluation of these locally-sited resources and move this type of analysis towards standard industry practice. This research and methodology can be used for both current decision-making at the SFPUC's development of the HPNS and for future developments of intelligent/micro-grids beyond San Francisco. The results provided herein are specific to the HPNS, but the process is widely-applicable to other jurisdictions.

Specific recommendations, including the implications of the use of this methodology in California and proposed next steps, are described in the Final Report for the Renewable Distributed Generation Assessment project, which captures the results from all four applications of this newly developed evaluation methodology.

ABSTRACT

This case study presents the results of the second application of a renewable distributed generation assessment methodology conducted for the San Francisco Public Utilities Commission (SFPUC). SFPUC is one of four distribution systems evaluated under the RDG Assessment project conducted under the auspices of the CEC PIER Renewables program. In addition to SFPUC, the three other distribution systems evaluated include Alameda Power & Telecom (Alameda P&T), City of Palo Alto Utilities (CPAU), and Sacramento Municipal Utility District (SMUD). The overall objective of this project is to accelerate the deployment of renewable energy systems in a distributed generation mode by fully accounting for all benefits.

Keywords: renewable distributed generation, assessment methodology, municipal utility planning, San Francisco Public Utilities Commission / Hetch Hetchy Water and Power, avoided costs, reliability analysis, uncertainty analysis

SAN FRANCISCO PUBLIC UTILITIES COMMISSION CASE STUDY

1.0 Introduction

This California Energy Commission (Energy Commission) PIER-funded Renewable Distributed Generation (RDG) Assessment project provides a sound methodology for utility distribution companies (UDCs) to evaluate the potential of RDG on their systems. With this project, Energy and Environmental Economics, Inc. (E3) and Electrotek Concepts® (ETEK) have developed methodologies and associated tools that municipal utilities can use to evaluate a wide variety of RDG options for their future resource planning needs. Given that many of the considerations for evaluation of electricity resources (e.g. market prices, fuel prices, technology costs, etc.) continually change, we designed this methodology to be flexible and able to address the dynamic nature of the electricity industry.

In this report, we provide the results from our application of the RDG assessment methodology for one of the four California municipal utilities that participated in the project – San Francisco Public Utilities Commission / Hetch Hetchy Water and Power (SFPUC). Each municipal utility had its own interests and goals for participation in this project and therefore, while the methodology is the same for each, the focus of our analysis and the subsequent results are tailored to meet the needs of each utility.

The RDG evaluation methodology involves two analytical processes that occur concurrently: an economic analysis and an engineering analysis. Throughout this report, we describe the results from both the economic and engineering analyses for the SFPUC RDG assessment. The SFPUC RDG assessment, along with the three other participating municipal utilities, provides an example of how RDG evaluation can be integrated into the utility planning process. The RDG assessment methodology provided herein can also be used in conjunction with other on-going Energy Commission PIER programs to develop a systematic and state-wide approach to evaluate RDG.

1.1. Background

In January 2003, E3 and ETEK began work under a California Energy Commission (Energy Commission) PIER program-funded to develop a methodology for evaluating renewable distributed generation (RDG) for municipal utilities. The following discussion of the analytical process and associated deliverables applies to each of the four participating municipal utilities; San Francisco Public Utilities Commission/ Hetch Hetchy (SF PUC), Alameda Power and Telecom (Alameda P&T), City of Palo Alto Utilities (CPAU), and Sacramento Municipal Utilities District (SMUD).

1.2. Overview of Analysis

This project was designed to identify the best renewable DG projects from both economic and engineering perspectives. This includes (1) identifying the best locations for RDG in a local Utility Distribution Company (UDC) system, (2) identifying reliability impacts in the analysis, and (3) assessing the impact of critical uncertainties on the results to provide robust

conclusions. Application of this research may result in reduced overall system costs, enhanced local reliability, and increased resource diversity.

The RDG assessment for each utility is developed in several sections; each section contains a major step in the evaluation. When taken together these sections contain our team's methodology for RDG planning and evaluation as applied in four specific case studies.

1. RDG Economic Screening Analysis consists of the following three steps:

Step 1: Define the baseline avoided costs

Step 2: Evaluate the cost-effectiveness of RDG from multiple perspectives

Step 3: Refine the potential of the RDG technologies that best suit the area needs with feedback from the engineering analysis

2. RDG Engineering Screening Analysis

Engineering Circuit Model. Using utility-specific data on system configuration and loading, ETEK developed a circuit model of each UDC's distribution system. This circuit model allows for the future analysis of the engineering impacts of RDG on the specific utility system.

Engineering Screening Analysis. The engineering analysis utilizes the ETEK circuit model to determine the timing, magnitude and location of constraints in the electric distribution system. The ETEK model analyzes the entire year, rather than a single peak load relying upon snapshots in time to evaluate how RDG output patterns interact with the distribution system. The analysis highlights the locations that need reinforcement and would benefit most from the siting of RDG, given expected performance characteristics and available resources.

Reliability Analysis. The reliability analysis chapter contains the impact of RDG on utility reliability using three complimentary methods. These methods are designed to evaluate the non-monetized impacts of RDG on electric reliability.

Method 1: Identifying the number of years (or amount of MW peak growth) of improved reliability from RDG installation

Method 2: Estimating the reduction in expected unserved energy (EUE) on the system from RDG installation

Method 3: Determining the reliability improvement for customers based on an estimate of Value of Service (VOS)

Uncertainty Analysis. The uncertainty analysis examines the sensitivity of the results and recommendations for cost effective and appropriately sited RDG to varying conditions. This analysis incorporates 'high' and 'low' range estimates of technical parameters, including market price, transmission costs, distribution costs, RDG capital costs, capacity factor, and fuel costs.

These analyses are interrelated as represented in Figure 2. The shaded areas represent the major analyses and the boxes in each area represent components involved in completing the analyses.

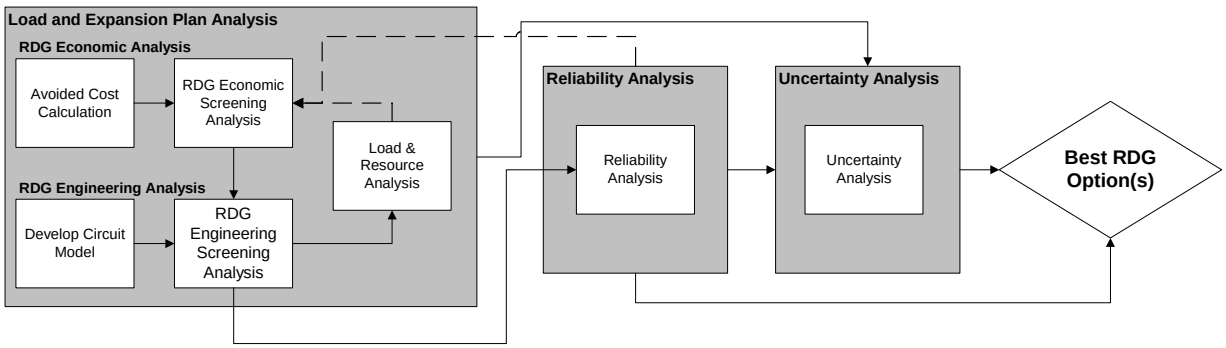

Figure 2: RDG Analysis Process Diagram

The flowchart indicates (dotted-line) that there is a potential feedback loop between the reliability analysis and the economic screening analysis. The normal progression of work is that the economic screen would determine if there are areas with sufficiently high avoided costs to justify RDG. Then the engineering screening analysis would be conducted to fine tune the amount, location, and timing of RDG installations that would be needed to defer or replace any planned generation, distribution, or transmission upgrades. The engineering investigation continues through the reliability analysis to determine how the selected RDG would affect service reliability. Based on both the engineering screening and reliability analyses, the economic screening analysis can then be further refined via feedback loops.

Similarly, the overall analysis can be refined through the consideration of uncertainty. The uncertainty analysis involves the perturbation of inputs to test the sensitivity of the results to a change in key inputs. Specific inputs that may be varied include electricity price forecast, RDG costs, distribution capacity value, and RDG fuel costs. The results from this uncertainty analysis allow for a more accurate recommendation of the 'best RDG option.'

1.3. Summary of Results for SFPUC

The results of our analysis for SFPUC are described in detail in each chapter of the RDG Assessment Report and highlights of these results are provided herein.

1.3.1. Economic Screening Analysis

We calculated the cost-effectiveness of each of the RDG alternatives according to the methodology described above. We compared lifecycle benefits and costs for each of the applicable tests on an NPV basis. A benefit/cost (B/C) ratio greater than 1.0 indicates that the alternative has a lifecycle benefit greater than its lifecycle cost and would therefore pass our initial economic screen.

Results are summarized in Table 1. Looking at this table, one can quickly see which RDG technologies are cost-effective based on direct costs and benefits as well as identify which other technologies may be close to a B/C ratio of 1.0 and warrant further evaluation. We have highlighted those technologies with a TRC B/C ratio greater than 1.0, and all the B/C ratios greater than 1.0 are shown in bold type. The Ratepayer Impact Measure (RIM) is calculated

assuming the RDG is owned by the customer, while the Utility Cost Test (UCT) is always calculated assuming utility ownership of the project. We evaluate the UCT in this manner because the UCT perspective under customer-ownership is not very revealing, since the utility enjoys the avoided cost savings without any of the ownership costs and the B/C ratio is always infinitely positive (in the absence of utility-paid incentives or other program costs).

Table 1: Results of SFPUC RDG screening, under base-case assumptions

	TRC Cost Test	Participant (Customer or Merchant)	RIM Test (Customer Owned)	UCT Test (Utility Owned)
Biogas - 10kW PEM Fuel Cell	0.42	0.71	0.39	0.28
Biogas - 10kW PEM Fuel Cell CHP	0.51	0.88	0.39	0.36
Biogas - 100kW SOFC Fuel Cell	0.61	**1.04**	0.39	0.40
Biogas - 100kW SOFC Fuel Cell CHP	0.71	**1.21**	0.39	0.49
Biogas - 200kW PAFC Fuel Cell	0.50	0.86	0.39	0.34
Biogas - 200kW PAFC Fuel Cell CHP	0.62	**1.07**	0.39	0.44
Biogas - 200kW PEM Fuel Cell	0.53	0.91	0.39	0.35
Biogas - 200kW PEM Fuel Cell CHP	0.70	**1.19**	0.39	0.48
Biogas - 250kW MCFC Fuel Cell	0.48	0.82	0.39	0.33
Biogas - 250kW MCFC Fuel Cell CHP	0.53	0.91	0.39	0.37
Biogas - 30 kW Microturbine	0.23	0.34	0.46	0.17
Biogas - 30 kW Microturbine w/ CHP	0.84	**1.44**	0.39	0.57
Biogas - 500 kW Gas Recip	0.43	0.62	0.46	0.30
Biogas - 800kW Gas Recip	0.55	0.81	0.46	0.38
Biogas - 800kW Gas Recip w/CHP	**1.41**	**2.42**	0.39	0.89
Biogas - 3MW Gas Recip	0.58	0.85	0.46	0.41
Biogas - 3MW Gas Recip w/CHP	**1.45**	**2.48**	0.39	0.90
Biogas - 5MW Gas Recip	0.59	0.86	0.46	0.42
Biogas - MSW Gassification	0.51	0.39	0.00	0.58
Biogas - 5kW Gas Engine	0.28	0.40	0.46	0.21
Biogas - 15kW Gas Engine	0.38	0.56	0.46	0.28
Biodiesel - 500kW	0.78	**1.08**	0.46	0.48
Solar - PV-5 kW	0.28	0.26	0.60	0.24
Solar - PV-50 kW	0.37	0.43	0.46	0.31
Solar - PV-100 kW	0.37	0.43	0.46	0.31
Solar - 25 kW Concentrating Sterling	0.20	0.18	0.00	0.35
Wind - Bergey WD -10kW	0.17	0.27	0.42	0.14
Wind - 750 kW Turbine	0.49	0.49	0.00	0.86
Wind - 1.5 MW Turbine	0.58	0.58	0.00	**1.01**
Sodium Sulfur Battery, 100 kW	0.63	0.81	0.47	0.44
Vanadium Redox Battery, 100 kW	0.41	0.60	0.46	0.32
Polysulfide Bromide Battery, 100 kW	0.42	0.54	0.47	0.29

As can be seen in Table 1, the 800 kW and 3 MW biogas generators with CHP were the only RDG technologies to pass the TRC test, with B/C ratios of 1.41 and 1.45, respectively. Both of these are relatively large generators which rely on an effective CHP installation to become cost-effective. These results illustrate that while cost-effective RDG exists, it may be difficult to find opportunities for application in most municipal utility territories.

These B/C ratio results allow for a quick determination of whether or not technologies are cost-effective, but these ratios do not give a sense of the magnitude of the difference between benefits and costs. Table 2 shows the $/kWh shortfall for each technology from the societal or TRC perspective. For example, in the case of the 30kW microturbine with CHP, there is a $0.012/kWh direct economic shortfall. Therefore, the value of the indirect benefits would need to be valued at greater than $0.012/kWh for this project to be pursued.

Table 2: Net Benefits of RDG Technologies

	Benefits	Costs	Net Benefits/ (Shortfall)
Biogas - 10kW PEM Fuel Cell	$0.063	$0.152	($0.089)
Biogas - 10kW PEM Fuel Cell CHP	$0.063	$0.124	($0.060)
Biogas - 100kW SOFC Fuel Cell	$0.063	$0.104	($0.041)
Biogas - 100kW SOFC Fuel Cell CHP	$0.063	$0.089	($0.026)
Biogas - 200kW PAFC Fuel Cell	$0.063	$0.127	($0.063)
Biogas - 200kW PAFC Fuel Cell CHP	$0.063	$0.102	($0.038)
Biogas - 200kW PEM Fuel Cell	$0.063	$0.119	($0.056)
Biogas - 200kW PEM Fuel Cell CHP	$0.063	$0.091	($0.028)
Biogas - 250kW MCFC Fuel Cell	$0.063	$0.132	($0.069)
Biogas - 250kW MCFC Fuel Cell CHP	$0.063	$0.119	($0.056)
Biogas - 30 kW Microturbine	$0.074	$0.317	($0.243)
Biogas - 30 kW Microturbine w/ CHP	$0.063	$0.075	($0.012)
Biogas - 500 kW Gas Recip	$0.074	$0.175	($0.100)
Biogas - 800kW Gas Recip	$0.074	$0.134	($0.060)
Biogas - 800kW Gas Recip w/CHP	$0.063	$0.045	$0.018
Biogas - 3MW Gas Recip	$0.074	$0.128	($0.053)
Biogas - 3MW Gas Recip w/CHP	$0.063	$0.044	$0.019
Biogas - 5MW Gas Recip	$0.074	$0.126	($0.052)
Biogas - MSW Gassification	$0.042	$0.081	($0.039)
Biogas - 5kW Gas Engine	$0.074	$0.269	($0.194)
Biogas - 15kW Gas Engine	$0.074	$0.194	($0.120)
Biodiesel - 500kW	$0.073	$0.095	($0.021)
Solar - PV-5 kW	$0.079	$0.282	($0.203)
Solar - PV-50 kW	$0.079	$0.216	($0.137)
Solar - PV-100 kW	$0.079	$0.216	($0.136)
Solar - 25 kW Concentrating Sterling	$0.039	$0.189	($0.150)
Wind - Bergey WD -10kW	$0.068	$0.398	($0.330)
Wind - 750 kW Turbine	$0.030	$0.062	($0.032)
Wind - 1.5 MW Turbine	$0.030	$0.053	($0.022)
Sodium Sulfur Battery, 100 kW	$0.078	$0.124	($0.046)
Vanadium Redox Battery, 100 kW	$0.074	$0.180	($0.105)
Polysulfide Bromide Battery, 100 kW	$0.078	$0.184	($0.106)

For each of the technologies in Table 1 and Table 2, we analyzed the sensitivity of results to uncertainties in the underlying assumptions. Figure 3 shows an example: the range of the TRC test results (net benefits) for the biogas 800 kW generator in $/kW for six key variables. This figure shows that the 800 kW generator is cost-effective under the TRC test in the Base Case (the central tick marks) and remains cost-effective under both our high and low scenarios of all key variables.

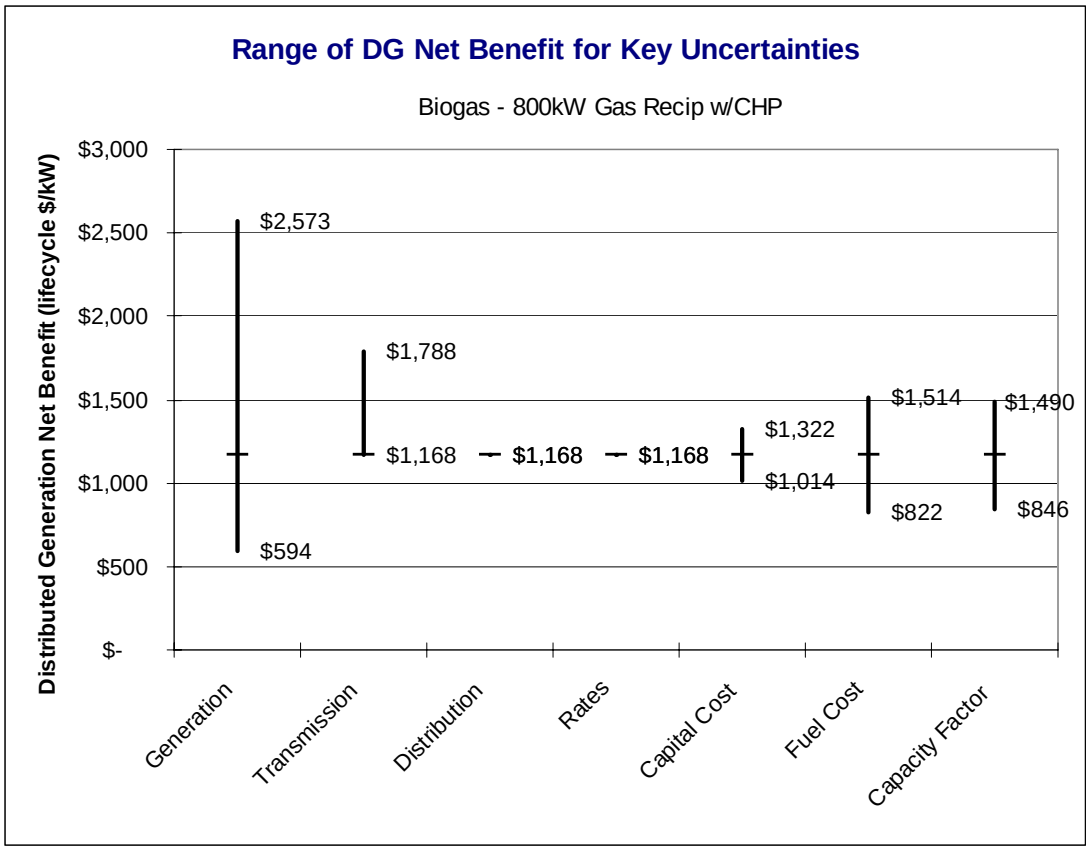

Figure 3: Net benefit range for key uncertainties from the TRC test perspective

In addition to computing the cost-effectiveness of RDG technologies and testing the sensitivity of these results to uncertainty in key inputs, we also evaluated RDG options in the context of the HPNS redevelopment schedule. In this analysis, we compared the net benefits of RDG to the traditional engineering solution for meeting the increased demand during the HPNS development. There are two predominant traditional engineering or 'wires' solutions to meet the HPNS increased demand:

1. Reconductor a portion of the existing 12kV line serving the HPNS
2. Upgrade the existing line to a 115kV line

The HPNS will be developed as parcels of land are acquired by the SFPUC. Figure 4 illustrates the increased electric demand associated with each parcel. The lines in this figure indicate when the traditional engineering solution would be required to ensure the increased load is reliably met.

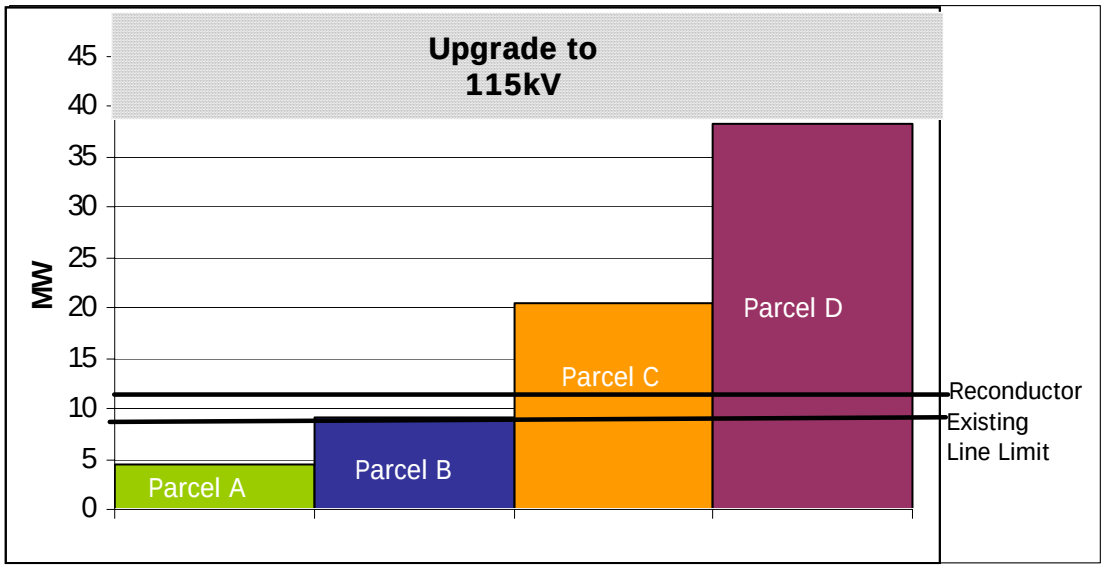

Figure 4: Electric Demand Levels (MW) as each HPNS Land Parcel is Developed

As discussed in detail in this report, our results show that a well-sited RDG technology can cost-effectively defer, or possibly obviate the need for, the traditional engineering solutions shown in Figure 4. However, only a few select technologies could be effectively implemented as part of an overall cost-effective integrated RDG solution.

1.3.2. Engineering Screening Analysis

The engineering screening analysis evaluates the feasibility of accommodating distributed generation and the potential value of that generation to the benefit of the power delivery system. The HPNS analysis is geographically limited to the distribution-level electric system shown in Figure 5. Figure 6 illustrates an intermediate result of the engineering analysis which is the peak load flow after Parcels A and B have been developed. In this figure, the thicker lines indicate greater energy flow.

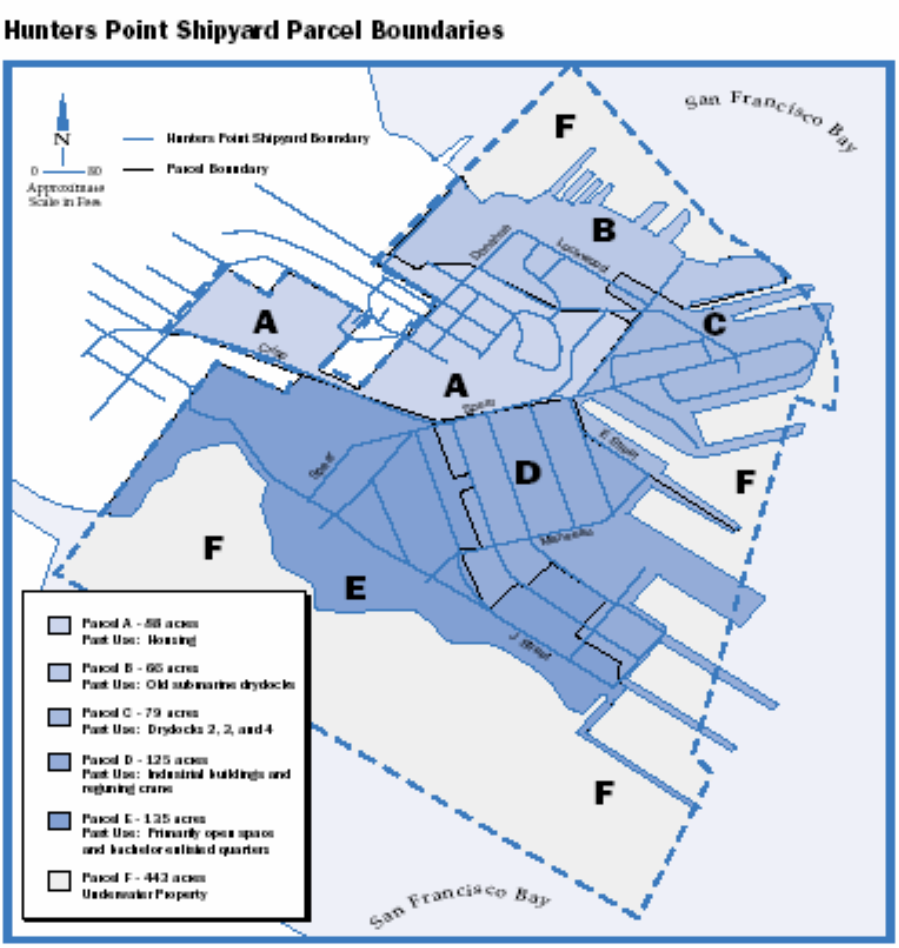

Figure 5: HPNS Map and Land Parcel Boundaries[1]

[1] Source: Hunters Point Shipyard Environmental Cleanup Newsletter, Southwest Division, Naval Facilities Engineering Command, Jan-March 2001, p. 2.

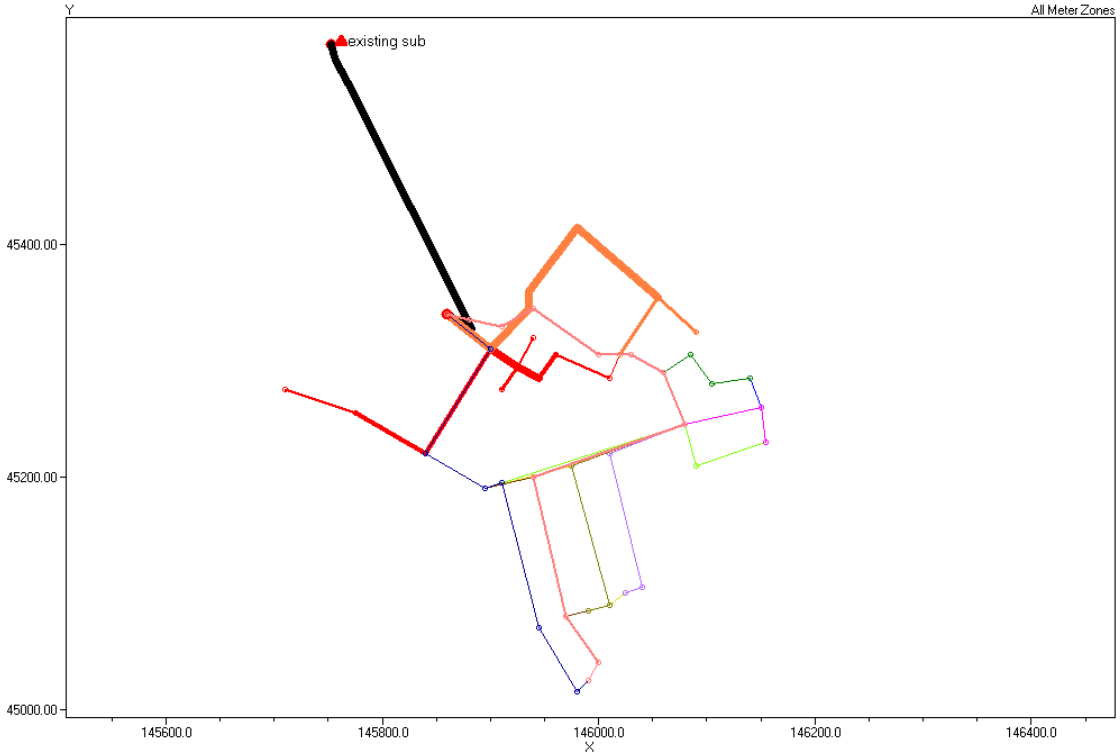

Figure 6: Peak Flow at HPNS after Development of Parcels A and B

The development can proceed through Phase 1 (Parcels A and B) with a relatively minor amount of peaking generation to cover potential overloads. Approximately 2 MW of dispatchable RDG would be required. It would be expected to operate the equivalent of 100 hrs per year, with the maximum run time each day averaging approximately six hrs.

To meet Phase 2 and Phase 3 load, a significant amount of base load RDG would have to be employed. Since the demand is higher in the winter, it would be conceivable to do this with two or more steps of base load RDG. The smaller step would be operated in the summer.

The RDG in Phases 2 and 3 would be operating a large percentage of the time. It would also require a relatively sophisticated control system to coordinate the dispatch with the limits on the power that can be drawn from PG&E.

Voltage regulation issues appear manageable for Phase 1 because the distances involved are relatively short. However, once the development extends to Phases 2 and 3, careful attention will have to be given to such engineering issues as voltage regulation and protection. The system makes a transition from a state where the utility source is dominant to one where the power supply in the development becomes dominant at times. At the higher load levels, management of the distribution system on Hunters Point will be similar to that of managing a micro-grid that is isolated from the utility system.

Benefits from RDG to a distribution system are very site specific and thus can have different values depending upon where the RDG is located. The 'optimal' location for RDG will depend on what is being optimized and is quite sensitive to the size of generation. The results of the RDG siting analysis are shown in Figure 7, where the circles represent the 'optimal" locations to place generation on the HPNS system for released capacity on the existing system.

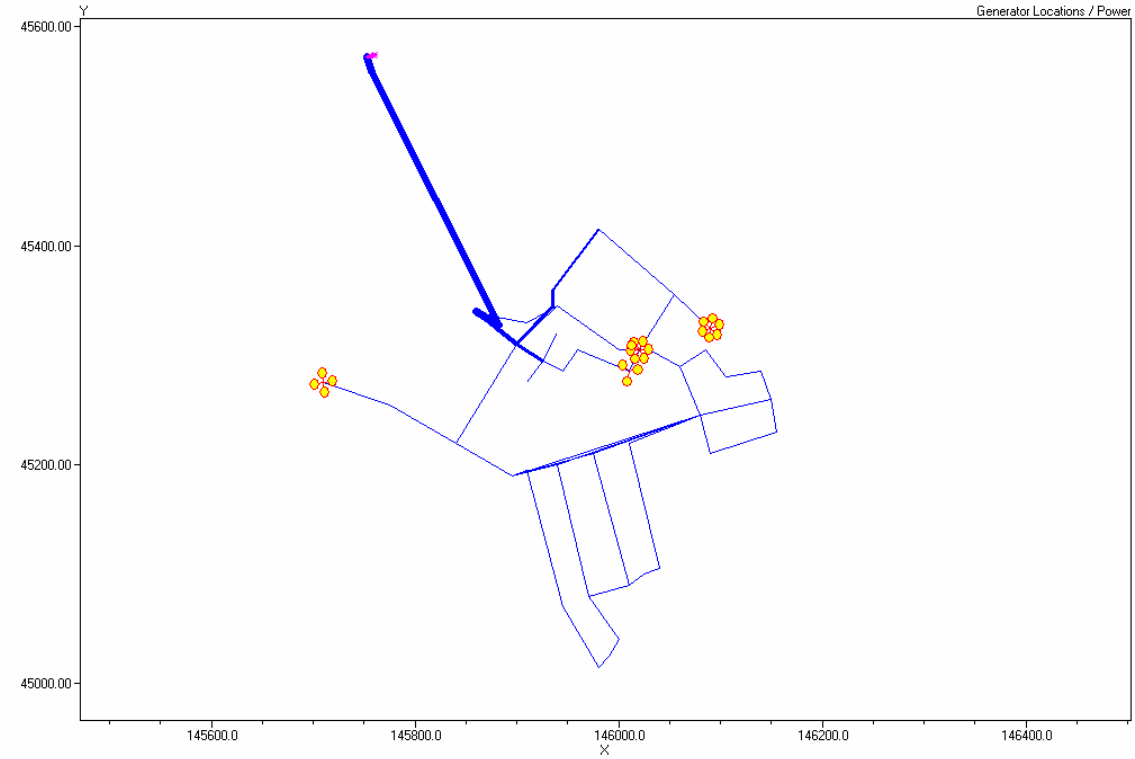

Figure 7: Phase 1b (Parcel A) DG Optimal Siting results

The SFPUC plans to integrate solar photovoltaics (PV) into the many of structures at the HPNS, including 1.2kW solar PV units on new residential units. Figure 8 and Figure 9 show the peak load profile after the first Phase of development is completed without solar PV and with solar PV, respectively. The PV will decrease annual energy import required but not completely eliminate the annual peak occurring in early fall and winter evening hours because the PV output is not 100% coincident with peak demand during those periods.

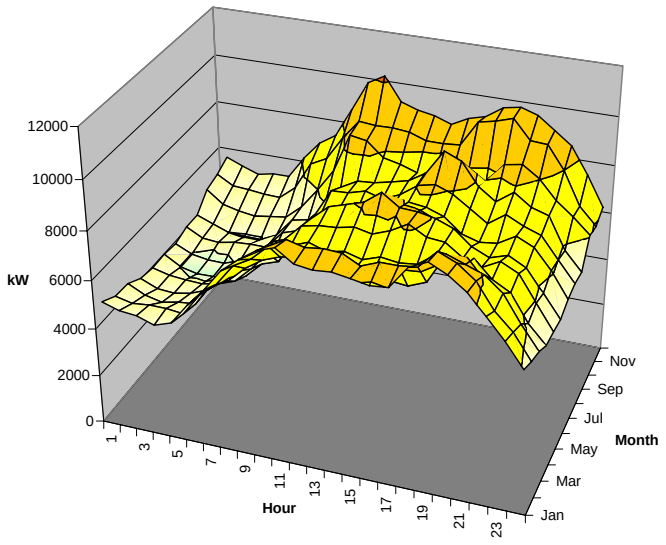

Figure 8: Phase 1b Peak Load Profile (no PV)

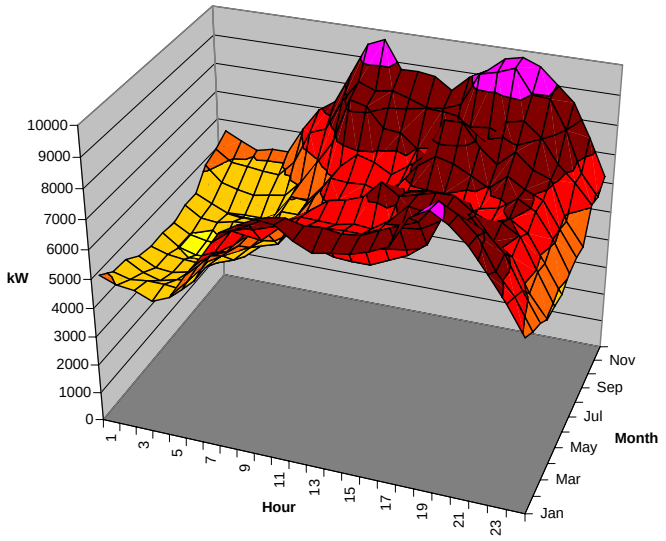

Figure 9: Phase 1b Peak Load Profile (with 3100 kW PV Generation)

Each of these analyses is described in greater detail in the Engineering Screening Analysis chapter of this report.

2.0 Economic Screening Analysis

The aim of our renewable distributed generation (RDG) analysis is to identify technologies that hold the potential for cost-effective installation in or near a utility's service territory. For the SFPUC, our analysis is aimed specifically at evaluating the potential for RDG at the Hunters Point Naval Shipyard (HPNS) area. RDG is deemed cost-effective if it yields positive net benefits:

Net Benefits = Benefits – Costs

Most of the benefits associated with RDG in the above equation are comprised of avoided costs, which are the described in detail in the section below. As there are many other benefits that may result from RDG installation, such as indirect environmental benefits, a discussion of these components follows.

2.1. Avoided Costs

Avoided costs, aptly named, are the costs that a utility can avoid incurring by taking an action under consideration, such as installing RDG technology. Thus, avoided costs can be thought of as the benchmark for cost-effectiveness evaluation of RDG technologies. If the avoided costs (the costs the utility would have incurred in the absence of RDG) are greater than the RDG costs, the RDG technology is cost-effective.

In this section, we focus on the methodology for determining avoided costs and present the results of our analysis of several potential avoided costs including generation, distribution, and transmission components within SFPUC's service territory. The actual comparison of benefits (avoided costs and other benefits) and costs (installed and operating costs of RDG) are addressed in the Economic Screening section.

This section is organized as follows:

1. General Avoided Cost Methodology
2. Generation Avoided Costs
3. Transmission Avoided Costs
4. Distribution Avoided Costs

2.1.1. General Avoided Cost Methodology

Throughout this analysis, we have drawn on information obtained from SFPUC and publicly available data sources to calculate avoided costs for SFPUC. Reduced energy commodity purchases (or increased sales), transmission costs, and distribution upgrades that can be avoided as a result of the installation of RDG at the HPNS area make up the avoided costs.

Avoided costs vary by both location and time, as each area may have different load, load growth, capacity limitations, and planned investments, and these characteristics vary over time. Avoided costs are highest in capacity constrained areas with near-term expansion plans because the cost of the planned expansion project may be deferred by the installation of RDG. Where a

local system has recently been expanded to provide adequate capacity to meet growth, avoided costs will be lower since meeting load with RDG would have no immediate effect on deferring distribution expansion.

The SFPUC is somewhat unique, in that it operates within the same jurisdiction as the investor-owned utility Pacific Gas & Electric Company and does not own any distribution facilities within the City of San Francisco. Rather, the SFPUC purchases both transmission and distribution services from PG&E. SFPUC's energy comes from its operation of the Hetch Hetchy hydroelectric system. The energy generated from the Hetch Hetchy system is more than sufficient to supply SFPUC's own customers, except during dry years. Excess energy is sold to the wholesale market if any remains. In dry hydro years, SFPUC purchases its shortfall from the wholesale market.

In dry hydro years, SFPUC's avoided costs are represented as the market price of electricity plus transmission and distribution costs. The same is true for periods of excess generation, as during these times RDG allows SFPUC to avoid transmission and distribution costs and sell additional energy at wholesale market prices. This situation is analogous to other municipal utilities either purchasing energy from the market when 'short', or selling to the market when 'long'.[2] In either case, the market price makes up the avoided cost of generation.

We describe our specific methodology and results for generation, transmission, and distribution avoided costs in the sections below.

2.1.2. Generation Avoided Costs

2.1.2.1. Generation Avoided Costs Methodology

As mentioned above, avoided generation costs are the reduced market electricity purchase costs, or increased market sales, that result from the installation of RDG. The most appropriate source of data for estimating avoided costs, when available, is forward market prices.

Electricity forward market price quotes are currently available through Platts' *Megawatt Daily* through 2007, and these make up the initial basis of our Base Case estimate for avoided generation costs. In the absence of forward price quotes for electricity beyond 2007, our forecast relies on a Long Run Marginal Costs (LRMC) forecast based on natural gas futures and fixed and variable costs of a Combined Cycle Gas Turbine (CCGT) plant as shown in Table 3, and described in greater detail below.

[2]The utility is 'short' when it has purchased less than 100% of its energy requirement in the forward market and is 'long' when it has purchased more than 100%.

Table 3: Base Case avoided generation cost forecast method by period

Period	Generation Cost Forecast Method
2006 -2007	Electricity Forward Price Quotes
2008 and Beyond	Long Run Marginal Cost (LRMC)

Any electricity price forecast may be substituted for our avoided cost forecast, though care should be taken to ensure the price reflects delivery to North of Path 15 (NP15), the closest wholesale trading point to San Francisco. Broker quotes offered directly to SFPUC are an excellent substitute for our avoided generation forecast for all years in which they are available.

Electricity Forward Market Price Quotes: 2006 – 2007

Through 2007, we base our market price forecast on forward price quotes from Platts' *Megawatt Daily*. The price quotes reported by Platts are based on daily surveys of electricity brokers and are reported for the peak period. We estimate the off-peak price to be 67% of the on-peak price, based on the historical relationship between peak and off-peak spot market prices.[3]

Long Run Marginal Cost (LRMC): 2008 and Beyond

In a period of system load and resource balance with a competitive marketplace for generation, the price of electricity can be expected to equal the Long Run Marginal Cost (LRMC) of production. For our forecast, we accept a consensus opinion of California utilities and the California Energy Commission (CEC) of system load and resource balance in 2008.[4] We assume the LRMC will be equal to the full cost of operating a combined cycle gas fired generator (CCGT). We chose CCGT as a proxy for LRMC because natural gas makes up the vast majority of planned plant additions in California and CCGT plants are the dominant technology at present.

Our assumptions regarding CCGT operating cost and performance were obtained from a CEC August 2003 staff report.[5] A key driver of CCGT cost is, of course, the cost of gas. We rely on NYMEX natural gas futures, which are available through 2010, and the CEC's most recent gas forecast (updated 4/8/2003) beyond 2010 for our gas price estimates.

2.1.2.2. Generation Avoided Cost Results

Table 4 shows the first 10 years of generation avoided cost inputs in E3's screening model. The data represent E3's Base Case electricity price forecast, calculated as described above.

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[3] We used California Power Exchange data from April 1998 through April 2000 to estimate this relationship.

[4] " Methodology and Forecast of the Long-Term Avoided Costs for the Evaluation of California Energy Efficiency Projects", Prepared for the California Public Utilities Commission, October 25, 2004, pp.47-48

[5] "Comparative Cost of California Central Station Electricity Generation Technologies" CEC Staff Final Report Aug 2003, Appendix D and Assumptions for Equity Return and Debt Interest Rates, Table 2.

Table 4: Screening model generation avoided cost inputs

Wholesale Energy Forecast (Nominal $/M	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Peak	$64.75	$62.25	$69.29	$66.13	$64.71	$65.01	$65.39	$67.44	$69.77	$72.17
Off-Peak	$43.35	$41.67	$46.38	$44.27	$43.32	$43.52	$43.77	$45.15	$46.71	$48.32

Table 5 shows the definition of the two TOU periods we have used in the model, which correspond to the peak and off-peak pricing periods in the forward electricity market quoted by Platts.

Table 5: Time-of-use period definitions

TOU Period	Definition	# of Hours in Period	% of Hours in Period
Peak	Mon-Sat, 6:00 AM to 10:00 PM (6x16), except holidays	4864	56%
Off-Peak	All other hours	3896	44%

Base case generation avoided costs are shown in Figure 10 along with the 20-year levelized stream for both the peak and off-peak periods.

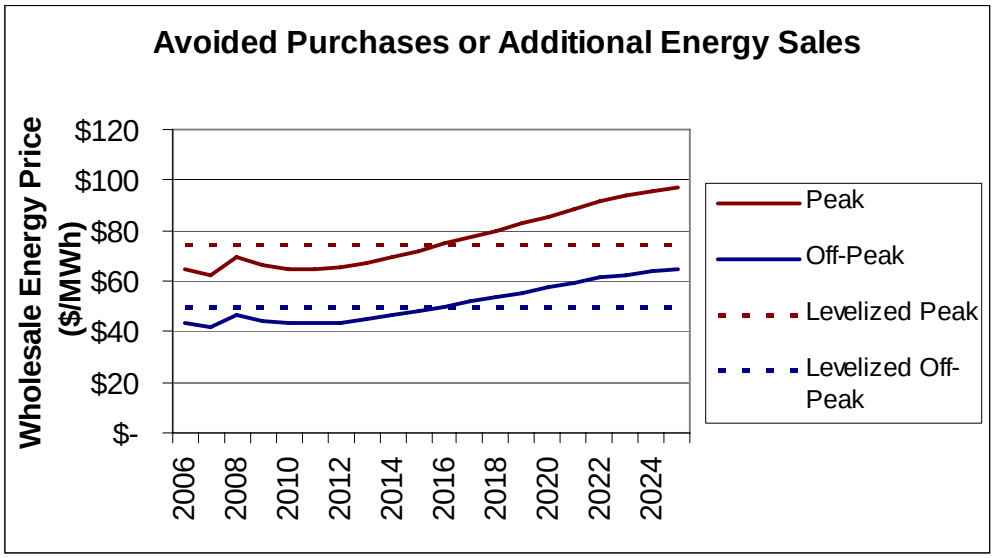

Figure 10: Avoided generation costs

All avoided costs are in nominal dollars. The 20-year levelized values in Figure 10 are the level payments required to produce the same total cost as the non-levelized stream, given the utility's discount rate. This value is $74.35/MWh in the peak period and $49.77/MWh in the off-peak period.

In Table 4 and Figure 10, one can observe a slight dip in forecast prices in 2007. This is a result of wholesale electric prices at NP15 being lower for 2007 than for 2006. There is another, slight dip in 2010. Since gas futures are available only through 2010, beginning in 2011 we use the CEC's most recent gas price forecast (4/8/2003), which is somewhat low compared to recent gas futures prices.

We also calculated 'high' and 'low' price scenarios for avoided generation costs. In our Base Case forecast, electricity prices for the years 2006 – 2007 are given by forward electricity prices. Since these are forward contracts that a utility can buy, the forecast represents a fully hedged position. For this reason, we hold the first two years of the Low scenarios constant with the Base Case. For years 2008 and beyond, we assume a market price equal to 80% of the Base Case.

We based our High generation avoided cost scenario on the SFPUC marginal retail rate of $82.89/MWh provided us by SFPUC. This number represents the additional revenue to the SFPUC from the sale of an additional MWh of energy, inclusive of T&D value. To incorporate this value, we netted out the T&D value and computed peak and off-peak values that resulted in an increase of the generation avoided costs of 38% over the Base Case. The marginal retail rate represents an upper bound on the value of RDG since the SFPUC could likely buy at the wholesale market price and sell to customers within the City.

The base, high, and low avoided generation cost scenarios are shown in Figure 11.

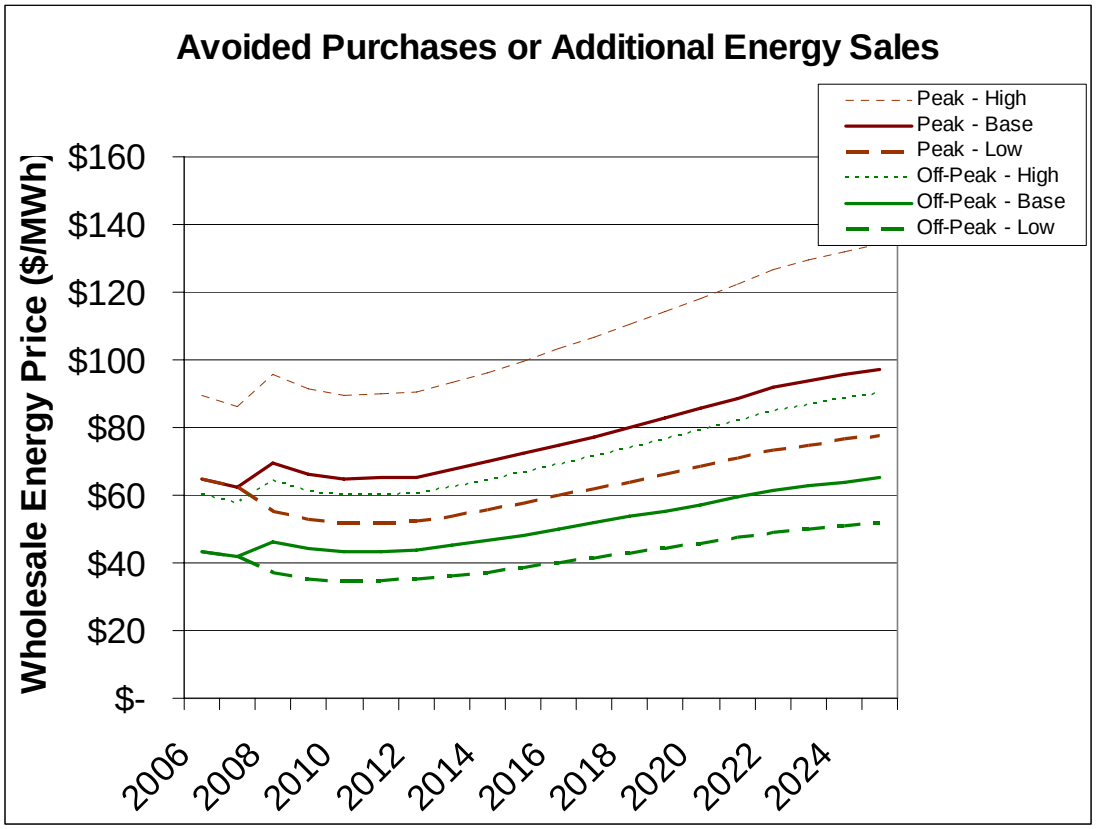

Figure 11: Comparison of base, high, and low scenarios for avoided generation costs

In the Uncertainty Analysis chapter, we discuss the sensitivity of benefit-cost analyses to the high and low scenarios shown above.

2.1.3. Transmission Avoided Costs

2.1.3.1. Transmission Avoided Costs Methodology

Transmission avoided costs for SFPUC consist of transmission charges paid to the California ISO that the utility would not have to pay if it had sufficient in-area generation to meet its load.[6]

Transmission avoided costs for a utility responsible for construction, operation, and maintenance of a portion of the transmission system could be calculated as the present value of the avoided transmission construction costs. However, since the SFPUC does not incur transmission investments, we simply apply the actual transmission charges paid to import power onto the local distribution system.

2.1.3.2. Transmission Avoided Cost Results

We estimate SFPUC's transmission charges to be $5.16/MWh. This represents the sum of the California ISO's High Voltage charges ($2.2381/MWh) and Low Voltage Wheeling charges ($2.926/MWh), which are the marginal avoidable transmission charges for SFPUC. This estimate is held constant over the life of the analysis to make up our Base Case and Low scenarios.

The High scenario reflects the uncertainty of a possible move to Locational Marginal Pricing (LMP), currently under consideration by the California ISO. Under LMP, the price of energy would reflect congestion on the grid, and the transmission charge would effectively become the energy price differential between points on the grid. The effects of a move to LMP are difficult to estimate, as the rules for the new market have not yet been established. We have assumed a value of $15/MWh to reasonably represent an upper bound of transmission costs under this scenario.

More detail on the sensitivity testing is provided in the Uncertainty Analysis chapter.

2.1.4. Distribution Avoided Costs

2.1.4.1. Distribution Avoided Costs Methodology

Distribution avoided costs result when RDG provides enough distribution system support to avoid distribution upgrades that would otherwise be required. Distribution avoided costs are often referred to as the 'deferral value' since the distribution upgrades are often only deferred and not avoided altogether. We typically use the Present Worth (PW) method to calculate the

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[6] This assumes transmission service is based, as it currently is, on net usage, meaning the amount of energy the utility takes through the transmission system (gross consumption net of any in-area generation). If transmission charges are based on *gross* usage, in area generation would be added back in for calculation of transmission charges, and no transmission avoided costs would ensue from DG.

avoided distribution costs. The PW method works well in areas with steady load growth since it can provide the distribution avoided cost in a $ per installed MW of RDG.

However, the anticipated load growth at the HPNS site results from a large-scale redevelopment to occur in three discrete phases. As such, we have evaluated the distribution costs assuming that blocks of electric loads will come on-line with the completion of each phase and sufficient capacity must be available to meet this load either through a distribution upgrade or RDG installation. At the completion of each development phase, we determine the amount of load that the system must be capable of serving and compare the costs of two alternative distribution upgrades to the cost of meeting the load with a RDG solution on a total lifecycle cost basis.

2.1.4.2. Distribution Avoided Cost Results

In this section, we discuss the initial results of the distribution avoided costs at the HPNS. A more detailed discussion how these results are employed in the analysis is provided in the Load and Resource Analysis chapter.

HPNS Redevelopment Load Growth

Table 6 shows the three planned phases of development at the HPNS and the expected peak load at the conclusion of each phase. These peak loads are used as our Base Case load growth forecast for this analysis.

Table 6: HPNS Planned Development Phases and Associated Load Growth

Development Phase	HPNS Land Parcel	Peak MW (from Phase)	Peak MW (cumulative)
Phase 1a	A	4.5	4.5
Phase 1b	B	4.6	9.1
Phase 2	C	11.5	20.7
Phase 3	D	17.8	38.4

The peak load levels shown in Table 6 are representative of the energy requirements for the planned development at the HPNS site which includes both residential and commercial loads. These peak load estimates do not include any significant energy efficiency measures beyond Phase 1a. However, the SFPUC is planning to incorporate additional energy efficiency measures into the development which would significantly reduce the peak load demand at the HPNS. Assuming that the feasible energy efficiency measures are incorporated into the development of the buildings at the HPNS, a 45% reduction of *peak* load requirements is expected.

Table 7 shows the expected peak load as a result of adding energy efficiency measures. The cumulative peak MW in the last column is shown here for illustrative purposes and is only an approximation of the impact based upon initial engineering studies for future development of the HPNS. A more detailed analysis of this impact is provided in the Load and Resource Analysis chapter of this study.

Table 7: Energy Efficiency Impact on HPNS Load Growth by Development Phase

Development Phase	HPNS Land Parcel	Peak MW (from Phase)	Peak MW (cumulative)
Phase 1a	A	4.5	4.5
Phase 1b	B	0.5	5.0
Phase 2	C	6.4	11.4
Phase 3	D	9.8	21.1

Phase 1 is broken out into two sub-phases Phase 1a and Phase 1b. Each phase of development relates to a geographically-distinct parcel of land at the HPNS site. Figure 12 shows a map of the HPNS parcel boundaries.

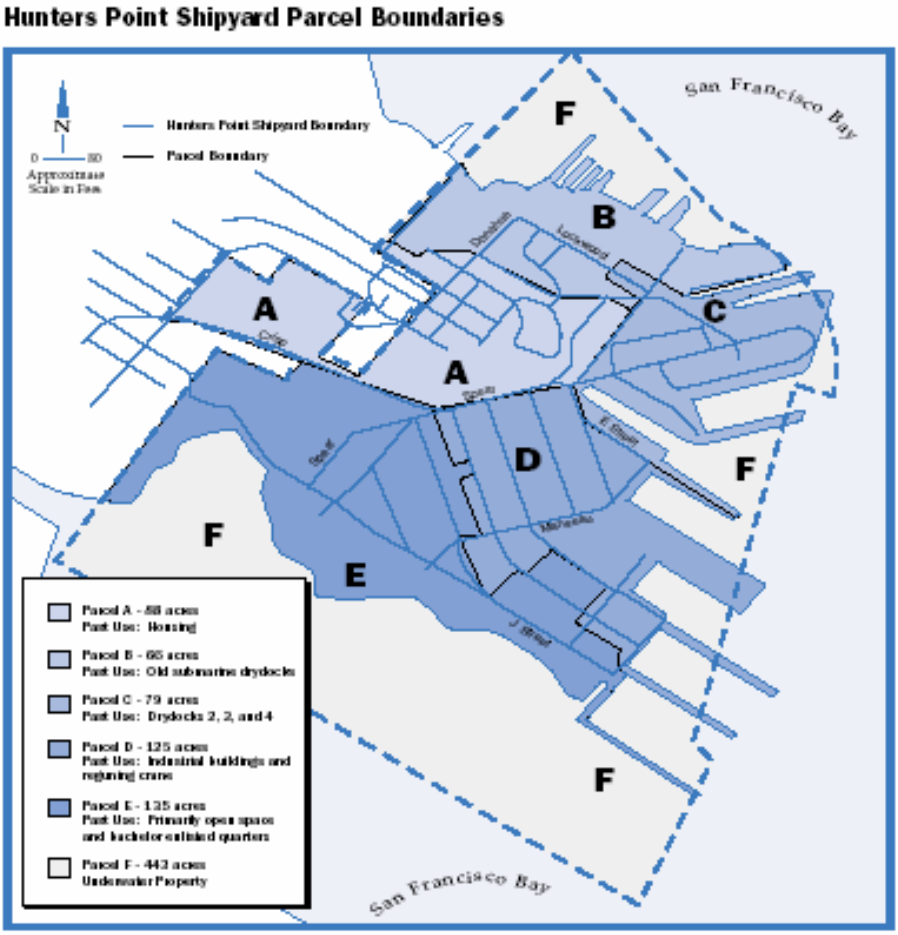

Figure 12: HPNS Map and Land Parcel Boundaries[7]

[7] Source: Hunters Point Shipyard Environmental Cleanup Newsletter, Southwest Division, Naval Facilities Engineering Command, Jan-March 2001, p. 2.

Distribution Upgrade Investments

At present, there are two primary 12kV feeders into the HPNS area, one that is typically used to serve the HPNS from the north with a capacity of approximately 8MW (at an assumed 95% loading level), and a backup feeder with an expected capacity to the HPNS of approximately 4MW from the west. When considering how to serve the new planned development load, we considered two primary engineering or 'wires' options available at different costs to upgrade the distribution system: 1) Reconductor the existing 12kV line or 2) Upgrade the 12kV line to a 115kV line and install a local substation.

The estimated engineering cost of the reconductoring option is $100,000, whereas the estimated engineering cost of the line upgrade is $1.25 million.[8] Since PG&E is the owner of the distribution system that serves the HPNS, any savings of capital deferral would either benefit PG&E ratepayers, or developers at the HPNS in the form of lower development costs.

Therefore, we assume for this analysis that the line upgrade costs are borne by PG&E and the avoided costs for this investment are calculated using PG&E's cost of capital (7.57%). Additionally, an inflation rate of 2% is assumed for this analysis.

Table 8 summarizes the assumptions used for the engineering or 'wires' solutions at the HPNS.

Table 8: Baseline Avoided Cost Assumptions for Wires Solutions

Phase 1b Start Year	2007
Phase 2 Start Year	2010
Phase 3 Start Year	2012
Reconductoring cost (000s, 2005$)	$ 100
115 kV upgrade cost (000s, 2005$)	$ 1,250

Using these assumptions, we calculate the cost value for each wires investment. For example, if we assume that the line is reconductored in Phase 2, the resulting present value cost of this investment is $62,271. Table 9 shows the results for each investment option if it were to be made during each particular phase. The present value cost of the investments decreases over time due to the effects of discounting. Also, we have netted a salvage value 20 years after the initial wires investment, so that we can appropriately compare wires investments to RDG investments in the Economic Screening and Load and Resource Analyses on a similar time frame. The salvage value is assumed to equal the remaining book value of the distribution upgrades after 20 years.

[8] In calculating the avoided costs, the engineering costs are increased by 30% to represent fully-loaded project costs.

Table 9: Present Value Cost of Investment Options

Present Value Cost, Net of Salvage (000s)			
	Phase 1	Phase 2	Phase 3
Reconductoring Cost	$66	$62	$60
Line Upgrade Cost	$824	$778	$749

Avoided Cost Analysis

Given the development of each phase at HPNS, we have mapped out the potential 'Paths' or series of choices that may occur throughout the HPNS redevelopment period to supply the load through combinations of wires options and RDG. Figure 13 identifies nine paths that initiate at Phase 1a and conclude at the end of Phase 3. These paths show the investment choices and order of investments as one proceeds down a particular path. Consider Path 6 in this analysis. There is no investment required in Phase 1a but a decision is required in Phase 1b. In this path, 1.8 MW of firm RDG is installed to meet the Phase 1b loads rather than reconductoring the existing 12kV line feeding the HPNS. As load grows in Phase 2, the wires investment option of upgrading the line to 115kV is elected and no further investments are needed to meet the remaining load growth at the HPNS. There is a particular cost associated with choosing Path 6 versus, say, Path 1. Throughout the remainder of the Economic Analysis, we will be evaluating the specific costs for each Path when considering different RDG technologies.

Figure 14 shows a similar decision-tree *after* the energy efficiency measures have been applied to the baseline development plans. In this case, the need for additional capacity does not arise until Phase 2, and thus the number of investment option paths is reduced from nine to five.

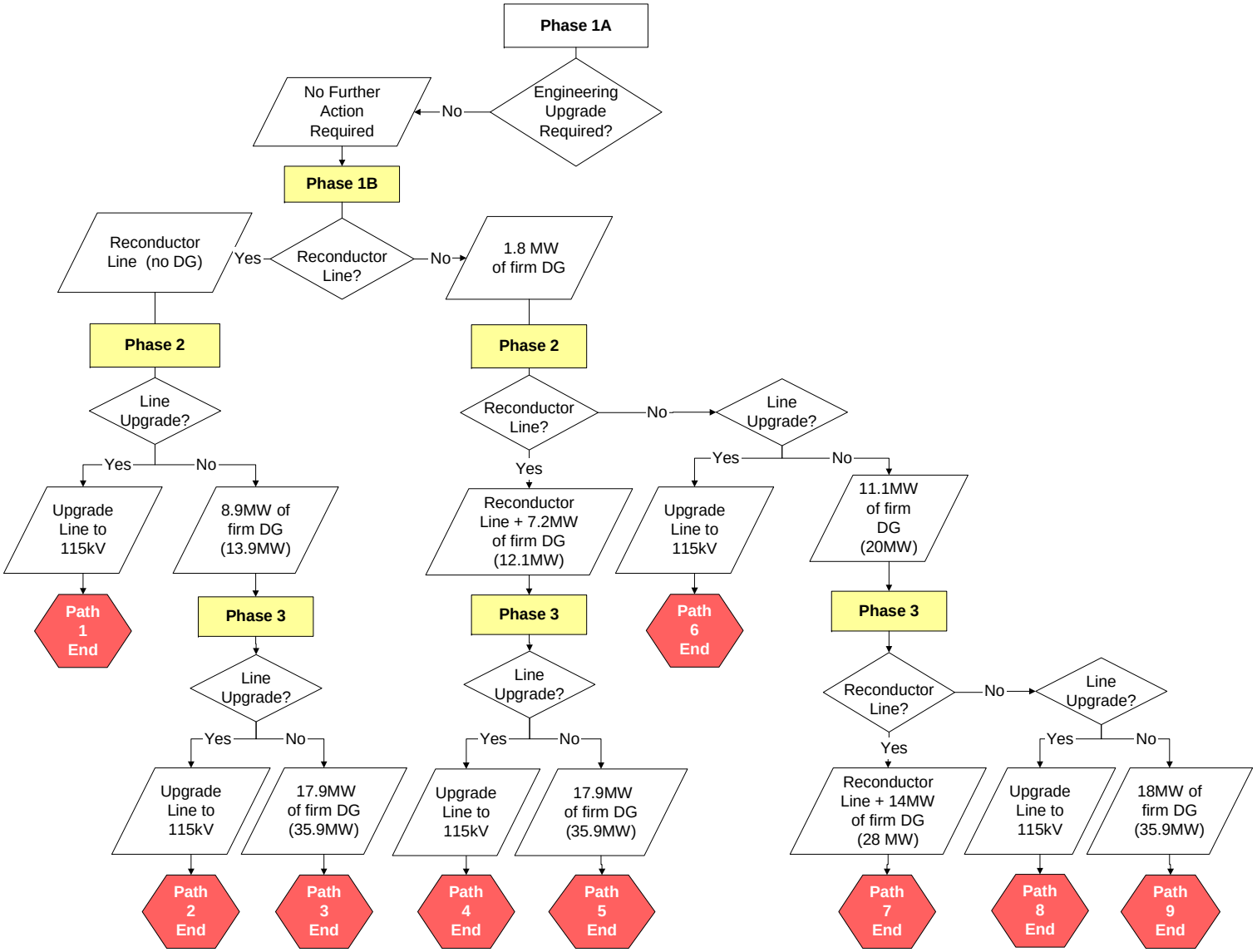

Figure 13: Paths for Investment Options at HPNS (no Energy Efficiency)

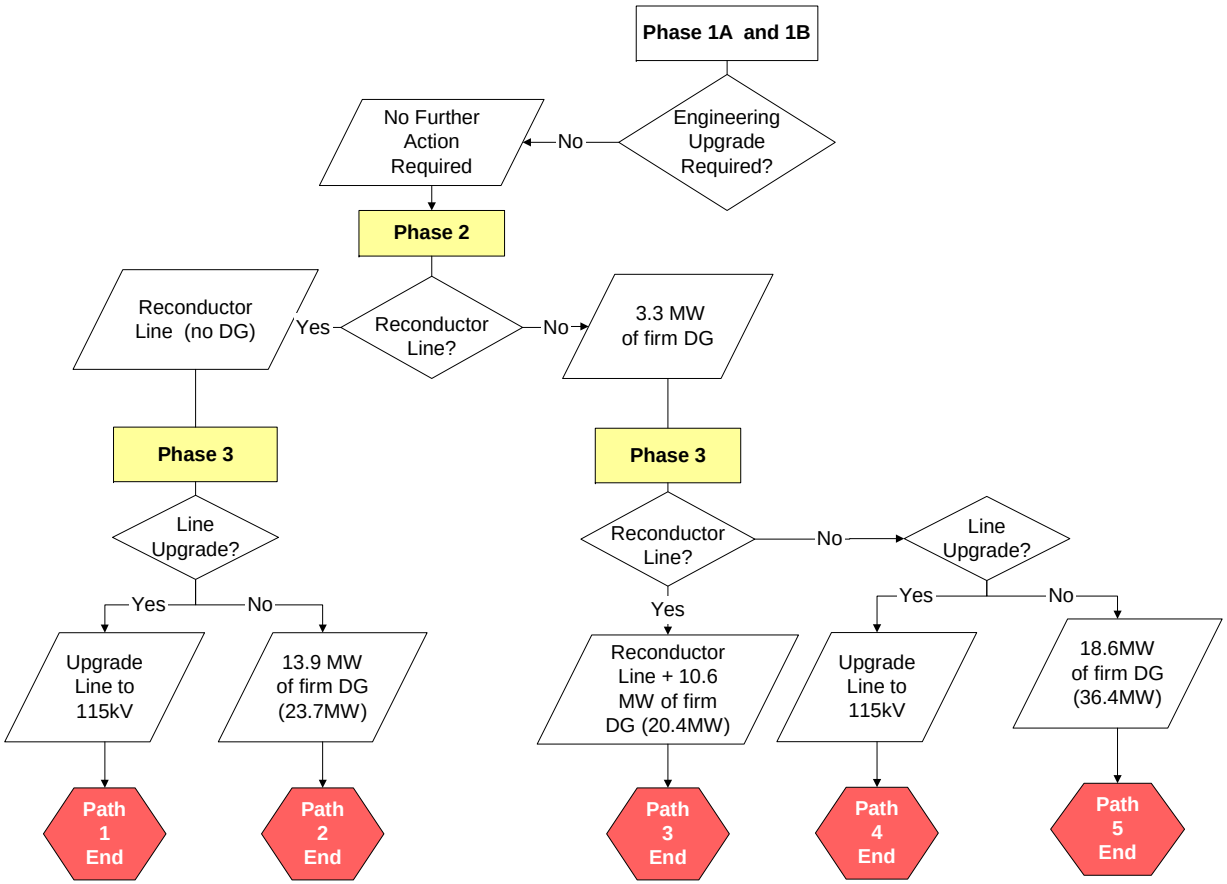

Figure 14: Paths for Investment Options at HPNS with Energy Efficiency Measures

The Economic Screening Analysis section focuses on the cost-effectiveness of RDG technologies that could be employed at the HPNS. The resulting cost-effectiveness of RDG will then be incorporated into the investment paths shown in Figure 13 and Figure 14 in the Load and Resource Analysis chapter to provide a basis for comparing each investment choice.

2.2. DG Economic Screening

In this section, we incorporate the results described in the avoided costs section to further develop the RDG economic analysis. The avoided costs are one element of the total benefits of RDG installation; total benefits are compared to total costs of RDG to determine RDG's cost-effectiveness.

The approach we take to evaluating potential RDG involves determining the economic cost-effectiveness of each technology from several different perspectives (e.g. RDG owner, utility, customer, and society). Specifically, we evaluated cost effectiveness from the perspective of five established 'cost tests':

- Participant Cost Test **:** This test measures the economic impact to the RDG owner.
- Ratepayer Impact Measure (RIM): This test measures the impact on utility operating margin and whether rates would have to increase to maintain the current levels if a customer installed RDG.
- Utility Cost Test (UCT): This test Measures the change in the amount the utility must collect from the customers every year if the utility owned the RDG.
- Total Resource Cost Test (TRC): This test measures the net direct economic impact to the community.
- Societal Cost Test: This test measures the net economic benefit to the community, as measured by the TRC, plus indirect benefits such as environmental benefits.

A common misperception is that there is a single best perspective for evaluation of cost-effectiveness. Each test is accurate, but the results of each test help to answer a different set of questions. In our analysis, we evaluate multiple perspectives to paint a more complete picture of the overall RDG project economics. The key questions answered by each cost test are shown in Table 10.

Table 10: Questions addressed by the five cost tests

Participant Cost Test	• Is it worth it to the customer to install RDG? • Is the customer likely to want to participate in a utility program that promotes RDG?
Ratepayer Impact Measure	• What is the impact of the RDG project on the utility's operating margin? • Would the project require an increase in rates to reach the same operating margin?
Utility Cost Test	• Do total utility costs increase or decrease? • What is the change in total customer bills required to keep the utility whole (the change in revenue requirement)?
Total Resource Cost Test	• What is the community benefit of the RDG project including the net costs and benefits to the utility and its customers? • Are all of the benefits greater than all of the costs (regardless of who pays the costs and who receives the benefits)? • Is more or less money required by the community to pay for energy needs?
Societal Cost Test	• What is the overall benefit to the community of the RDG project, including indirect benefits? • Are all of the benefits, including indirect benefits, greater than all of the costs (regardless of who pays the costs and who receives the benefits)?

In Table 11, we list the specific benefit and cost components that are attributed to each cost test perspective in our economic screening. These are the easily identified and typical direct costs and benefits that can be associated with RDG. We have also included a category entitled 'Other Direct Benefits' to capture other specific, measurable benefits that may be identified.

Table 11: Benefits and Costs of RDG from Five Cost-Effectiveness Test Perspectives

Tests and Perspective	Costs	Benefits
Participant Cost Test	• RDG capital and operating costs	• Participation incentives • Energy sales and/or bill savings • Equipment rebate
Utility Cost Test (UCT) Distribution Utility as DG Owner	• RDG capital and operating costs • Siting costs for utility-owned RDG	• Transmission tariff savings • Distribution capacity savings • Energy savings • Voltage support • Other direct benefits, such as lower tipping fees for solid waste
Ratepayer Impact Measure (RIM)	• Revenue loss • Incentive payments • Equipment rebate • Administrative costs	• Transmission tariff savings • Distribution capacity savings • Voltage support • Energy savings
Total Resources Cost Test (TRC)	• RDG capital and operating costs • Administrative costs	• Distribution capacity savings • Energy sales and/or savings • Transmission tariff savings • Other direct benefits, such as lower tipping fees for solid waste
Societal Cost Test	• RDG capital and operating costs • Administrative costs	• Distribution capacity savings • Voltage support • Energy sales and/or savings • Other direct benefits • Transmission tariff savings • Indirect benefits, such as reduced emissions and increased property value

The primary difference between the TRC and Societal tests is the inclusion in the Societal test of externalities or indirect benefits such as cleaner air and increased local property values, elements for which a clear price or economic valuation may not exist. To avoid diluting results by mixing these indirect, unpriced values with known, priced values, our methodology relies on a 'gap analysis' to evaluate the Societal test perspective. The gap analysis measures direct benefits against direct costs and weighs the economic 'gap', if any, against a list of indirect benefits. We discuss the gap analysis in more detail in the Indirect Benefits Section.

2.3. Calculation of Costs and Benefits

This section describes in greater detail our methodology for calculating the benefits and costs that enter into the cost tests described above. We have made an effort to simplify the inherent complexity in some of the inputs and calculations for ease of use but only if these simplifications do not affect the robustness of the results. In every case, we calculate the net present value (NPV) of the stream of costs and benefits, based on the discount rate appropriate to the test perspective, and compare the two. Our results are presented in this memo on an NPV basis.

2.3.1. Costs of RDG

For the Participant, TRC, and Utility (assuming utility RDG Ownership) test perspectives, the costs of RDG comprise the capital, fuel, and O&M (fixed and variable) costs of the RDG technology under evaluation.

Table 12 shows the key RDG performance characteristics and cost data we used in our analysis. We used publicly available information on commercially available and emerging technologies. Additional information on RDG technologies is available in Appendix A.

For the RIM test perspective, RDG capital and operating costs of non-utility RDG applications are excluded since these costs are born by the participant and have no impact on the utility's rates or operating margin. Instead, costs in the RIM test include lost revenues due to reductions in the participant's energy bill. The RIM test also includes as costs any incentives paid by the utility to participants and any administrative costs associated with a utility DG program.

Table 12: RDG performance characteristics

Technology Name	Municipal Utility Incentive Cost $/kW	Generator Life (Years)	Fuel Type: (1)No Cost (solar, hydro, wind) (2) Biodiesel 80/20 (3) MSW Delivery and Process. $/MMBtu (4) Landfill Gas (5) Off Peak Energy ($/kWh)	Heat Rate (Net Heat Rate for CHP Applications)	Capital Cost $/kW	Install Cost $/kW	Fixed O&M $/kW-yr	Variable O&M $/kWh
Biogas - 10kW PEM Fuel Cell	$0	10	4	11,370	$5,500	0	$18.00	$0.03
Biogas - 10kW PEM Fuel Cell CHP	$0	10	4	6,370	$5,500	0	$18.00	$0.03
Biogas - 100kW SOFC Fuel Cell	$0	10	4	8,338	$3,500	0	$10.00	$0.02
Biogas - 100kW SOFC Fuel Cell CHP	$0	10	4	5,731	$3,500	0	$10.00	$0.02
Biogas - 200kW PAFC Fuel Cell	$0	10	4	9,480	$4,500	0	$6.50	$0.03
Biogas - 200kW PAFC Fuel Cell CHP	$0	10	4	5,105	$4,500	0	$6.50	$0.03
Biogas - 200kW PEM Fuel Cell	$0	10	4	10,725	$3,600	0	$6.50	$0.02
Biogas - 200kW PEM Fuel Cell CHP	$0	10	4	5,775	$3,600	0	$6.50	$0.02
Biogas - 250kW MCFC Fuel Cell	$0	10	4	7,930	$5,000	0	$5.00	$0.04
Biogas - 250kW MCFC Fuel Cell CHP	$0	10	4	5,730	$5,000	0	$5.00	$0.04
Biogas - 30 kW Microturbine	$0	10	4	15,070	$2,260	0	$0.00	$0.02
Biogas - 30 kW Microturbine w/ CHP	$0	10	4	5,434	$2,630	0	$0.00	$0.02
Biogas - 500 kW Gas Recip	$0	10	4	12,003	$936	0	$26.50	$0.00
Biogas - 800kW Gas Recip	$0	10	4	10,246	$724	0	$0.00	$0.01
Biogas - 800kW Gas Recip w/CHP	$0	10	4	4,771	$971	0	$0.00	$0.01
Biogas - 3MW Gas Recip	$0	10	4	9,492	$702	0	$0.00	$0.01
Biogas - 3MW Gas Recip w/CHP	$0	10	4	4,857	$864	0	$0.00	$0.01
Biogas - 5MW Gas Recip	$0	10	4	8,758	$727	0	$0.00	$0.01
Biogas - MSW Gassification	$0	15	3	8,000	$5,179	0	$20.00	$0.00
Biogas - 5kW Gas Engine	$0	10	4	12,010	$1,970	0	$0.00	$0.02
Biogas - 15kW Gas Engine	$0	10	4	10,404	$1,300	0	$0.00	$0.02
Biodiesel - 500kW	$0	12.5	2	10,314	$386	0	$26.50	$0.00
Solar - PV-5 kW	$0	20	1	-	$8,650	0	$14.30	$0.00
Solar - PV-50 kW	$0	20	1	-	$6,675	0	$5.00	$0.00
Solar - PV-100 kW	$0	20	1	-	$6,675	0	$2.85	$0.00
Solar - 25 kW Concentrating Sterling	$0	20	1	-	$5,700	0	$20.00	$0.00
Wind - Bergey WD -10kW	$0	10	1	-	$6,055	0	$5.70	$0.00
Wind - 750 kW Turbine	$0	20	1	-	$1,200	0	$15.00	$0.00
Wind - 1.5 MW Turbine	$0	20	1	-	$1,000	0	$15.00	$0.00
Sodium Sulfur Battery, 100 kW	$0	15	5	76.7%	$2,168	100	$51.20	$0.0041
Vanadium Redox Battery, 100 kW	$0	10	5	70.0%	$2,522	100	$54.80	$0.0022
Polysulfide Bromide Battery, 100 kW	$0	15	5	62.5%	$1,415	100	$80.30	$0.0036

For those technologies that operate with an external fuel source, such as reciprocating engines or fuel cells, we have included distinct fuel prices for several renewable fuels. These fuel prices are shown in Table 13.

Table 13: 2004 RDG fuel prices

Biodiesel 80/20	$8.58
MSW Delivery and Process. $/MMBtu	$8.00
Landfill Gas	$9.50

The fuel costs shown in Table 13 are escalated at a rate of 2% per year in our analysis. The biodiesel cost of $8.58/MMBtu is based on a cost of $1.26 per gallon. Although the cost of biodiesel depends on the market price of vegetable oil, B20 biodiesel is typically about $0.20/gallon more expensive than regular diesel fuel. Diesel fuel spot prices in the Western U.S. are currently abnormally high (roughly $1.25/gallon in Los Angeles, implying a biodiesel cost of roughly $1.45/gallon), but we believe that for this long-term planning analysis, a more 'normal' value of roughly $1/gallon is more reasonable.

Landfill gas is free, but capturing it involves capital costs of $6-13/MMBtu/year and O&M costs of 13-74 cents/MMBtu/year, according to an EPA presentation from the Landfill Methane Outreach Program.[9] Similarly, municipal solid waste (MSW) is free, and plentiful, but the gasification process results in an overall cost not included in the capital and O&M cost of a generator. The MSW costs included in our model are based upon vendor quotes for the gasification process but can vary depending upon the waste streams and system configuration. To address this issue of cost variation, we test the impact of changes in fuel cost in the Uncertainty Analysis chapter and are able to observe any changes in RDG cost-effectiveness resulting from higher or lower fuel costs.

2.3.2. Generation Energy Benefits

One of the main benefits of RDG is the energy that is generated. For the utility, this can offset market purchases that would otherwise be necessary. For customer-owned RDG, this can reduce their utility bill. Depending on the perspective and type of RDG, therefore, our analysis values energy differently. The energy generated by RDG is valued at the wholesale level for the utility, merchant plant, and social perspectives, and at the retail, or bill savings, level for participants who install RDG on site, as shown in Table 14.

[9] http://www.eere.energy.gov/greenpower/conference/5gpmc00/tkerr.pdf

Table 14: Generation benefits by test perspective

Value Basis	Calculation	Participant Test	RIM Test	TRC Test	UCT (Utility owned DG)
Wholesale	Market prices x RDG output x Line Loss	Benefit (merchant plant)	Benefit	Benefit	Benefit
Retail	Rates x RDG output	Benefit (behind the meter installation)	Cost	Transfer	N/A

2.3.2.1. Wholesale Energy

When evaluating the wholesale value of energy, we use the forecast of prices at NP15 as described in the Avoided Cost section. Market prices are the appropriate measure of avoided costs from the utility's perspective because when the utility is buying energy, RDG allows the utility to save the money it would have spent on electricity purchases and when the utility is selling energy, RDG allows the utility to increase sales of excess energy into the market. Market prices are also the appropriate measure of benefits from the merchant plant perspective because they represent the value that can be obtained by selling power into the market.

When valuing the wholesale value of energy, we adjust for the losses between the RDG interconnection point and NP15. The line loss factor in the wholesale generation calculation in Table 14 is a feedback from the results of the engineering analysis. This is included so that the benefits of reduced losses are captured for RDG installations. No additional procurement or scheduling costs for in-area generation were included in calculating the generation costs and benefits.

An additional benefit for a dispatchable RDG technology that is not specifically calculated in this analysis is the ability to generate additional energy during hours with very high spot prices or during requests from the ISO for rotating outages. For those technologies that could be optimally dispatched with regard to market price signals, this additional benefit could be substantial. We have not modeled this benefit because most of the RDG technologies with low or zero fuel cost will operate as available and will not be dispatched on an as-needed basis. The exception might be an internal combustion engine operating on biodiesel in which case additional benefits could be added. However, since most utility energy purchases are made with the on- and off-peak wholesale energy blocks, we feel these prices are appropriate for the cost-effectiveness screening analysis.

2.3.2.2. Retail Energy

For behind-the-meter installations, the energy benefit to the customer is the reduction in utility bills. We multiply RDG output by rates to compute customer bill savings. Lower bills are considered a cost to the other ratepayers (RIM test perspective), as this is the revenue loss to the utility when a customer operates their RDG.

We have designed our analysis to calculate bill reductions and revenue loss based on the rates that reflect the change in the bill when RDG is operational. Table 15 shows the estimated average residential, commercial, and industrial rates used in our analysis. Since the customers at the HPNS would be served by PG&E under the current ownership structure, these are based on PG&E's applicable rates.

Table 15: Average rates used in analysis

Average Rates in 2006	Total Rate	Unavoidable Component
Residential $/kWh	$0.125	$0.00
Commercial $/kWh	$0.161	$0.00
Industrial $/kWh	$0.122	$0.00

2.3.3. Transmission Benefits

Transmission avoided costs for a municipal distribution utility are based on reduced transmission charges paid to the transmission owner. As discussed in the Avoided Cost section, our analysis allows different scenarios of transmission pricing to be modeled. In the Base Case, we estimate SFPUC's transmission charges to be $5.16/MWh. This represents the sum of the California ISO's High Voltage charges ($2.2381/MWh) and Low Voltage Wheeling charges ($2.926/MWh), which are the marginal avoidable transmission charges for SFPUC.

Transmission savings are applied only when the RDG interconnection point is on the municipal utility system (i.e. at the customer or secondary distribution level) and reduces municipal loads on the transmission system. Interconnections on the transmission system at the primary or bulk transmission level do not result in any reductions in transmission fees.

The RDG output is increased by line losses to the utility interconnection point to calculate the total value of transmission savings, since a larger amount of energy would need to be transmitted in order to replace the RDG output at the customer. Since line losses vary over time, we estimate losses by TOU period. Table 16 shows the assumptions used for losses in this analysis.

Table 16: Losses from Interconnection Point to Trading Point (e.g. NP-15)

Interconnection Point of Generator	Customer	Secondary	Primary	Bulk System
Peak	7.90%	7.90%	5.60%	3.90%
Off-Peak	6.90%	6.90%	5.10%	3.90%

2.3.4. Distribution Capacity Benefits

Distribution capacity savings are achieved when a distribution capacity investment project is delayed as a result of capacity benefits from sufficient RDG interconnecting with the electrical system. Distribution capacity savings are only applied in cases where the RDG interconnection point is at the customer or on the secondary distribution system and the RDG can defer a planned distribution investment. When RDG interconnects at the primary or bulk transmission level, no avoided distribution capacity costs can be realized on the distribution system because the RDG has no effect on planned distribution investments.

As discussed in the Avoided Cost section, we have included distribution capacity benefits by evaluating each combination of distribution and RDG that can deliver adequate capacity at each phase of the HPNS development. With this approach, the more expensive the distribution upgrades are, the better an RDG solution will look by comparison.

2.3.4.1. Realizing Distribution Benefits

In order to achieve distribution benefits with RDG, ultimately a distribution engineer must be confident that the RDG installation will not result in a reduction in service quality compared to the planned system upgrade. Typically, if an engineer is not confident of the reliability of the RDG solution, they will likely build distribution to maintain reliability. Generally, this means that RDG must meet the same minimum reliability standards as the conventional wires solution.

As the local system relies more and more heavily on RDG for reliability, the problems of evaluating the total reliability becomes more complex. An initial engineering assessment is provided in the Load and Resources chapter, however, research is just beginning on how to balance and maintain reliability on a system such as the HPNS after the redevelopment is complete without a distribution system upgrade.

2.3.5. Reliability Benefits

Electric reliability is a measure of the electric system's ability to deliver uninterrupted power within specified power quality tolerances. Reliability benefits of RDG occur when the installed RDG increases the reliability of the distribution system or prevents load shedding due to transmission or system capacity constraints. As described in the Reliability Analysis chapter, there are several methods of quantifying reliability benefits. In our analysis, we quantify reliability benefits using estimates of Value of Service (VOS) and Expected Unserved Energy (EUE). The VOS metrics serve as an annual value 'proxy' to decide when to make additional investment based on the value to customers.

We compute a weighted VOS based on the proportion of each customer class served on the feeder or system affected by the RDG, and the per kWh VOS for each customer class. The VOS estimates are derived from studies that query customers on how much they would be willing to pay to avoid an outage. The per kWh VOS values are much higher

than electricity rates. VOS values have historically been reported in the range of $5 to $30 dollars per kWh in survey studies but these values do not reflect a specific VOS survey conducted for California municipal utilities as part of this analysis.[10,11]

The change in EUE is calculated in the engineering analysis, as described in the Reliability Analysis chapter. We allow a 10-year horizon for the change in EUE, as this is generally the longest term over which utility reliability planning occurs. The reduction in EUE is multiplied by the VOS to arrive at an annual dollar value for reliability benefits.

2.3.6. Other Direct Benefits

Other direct benefits we compute include:

- Community Direct Benefits
- Utility Direct Benefits
- RDG Customer Direct Benefits
- Merchant Plant Owner Direct Benefits
- Non-Municipal Incentives

The first four items act as placeholders for any measurable direct impacts of RDG not captured in other parts of the analysis. Inclusion of these items makes the analysis more flexible, since any additional value streams that are identified can easily be added. An example is reduced tipping fees (solid waste disposal costs) for municipal solid waste (MSW) in the case where MSW would be used as a fuel source for RDG.

We model these benefits on a *$/kWh produced* value. For example, we set the reduced tipping fees resulting from MSW gasification at $0.01/kWh produced. This means that for every kWh of energy produced by MSW gasification RDG, waste disposal at a landfill would be reduced enough to reduce tipping fees by 1 cent. Any other identified benefits should be calculated in the same fashion.

Non-municipal incentives are participation incentives not paid by the municipal utility, such as Federal tax refunds or state rebates. They are included as a benefit in the Participant Cost Test, as they make RDG more attractive to participants. Incentives from outside the municipal utility are also included as a benefit in the TRC test, which we have defined from a community perspective.

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[10] Woo, Chi-Keung, R. Pupp, T. Flaim, R. Mango, "How Much Do Electric Customers Want to Pay for Reliability? New Evidence on an Old Controversy", *Energy Systems and Policy*, Volume 15, pp. 145-159, 1991

[11] Keane, Dennis, C.K. Woo, "Using Customer Outage Costs to Plan Generation Reliability", *Energy,* Volume 17, No. 9, pp. 823-827, 1992

2.3.7. Indirect Benefits of Renewable DG

The benefit/cost analysis described above considers the quantifiable financial benefits and costs of RDG. There are also other RDG benefits, such as reduced environmental degradation, that are much more difficult to measure. While it may be possible to estimate dollar values for some of these elements – emissions, for example, have quantifiable costs in terms of permitting costs – the applicability of these elements to a particular RDG technology, the importance of the elements to a particular municipality, and the dollar or non-dollar value assigned to the elements are largely a judgment call. For example, the San Francisco's Electricity Resource Plan includes the following goals.[12]

- Maximize Energy Efficiency
- Develop Renewable Power
- Assure Reliable Power
- Support Affordable Electric Bills
- Improve Air Quality and Prevent Other Environmental Impacts
- Support Environmental Justice
- Promote Opportunities for Economic Development
- Increase Local Control Over Energy Resources

In support of these goals, we offer Figure 15 as an aid in identifying the major indirect value streams that could be considered in accounting for the total value of RDG.

[12] "The Electricity Resource Plan: Choosing San Francisco's Energy Future" San Francisco Public Utilities Commission, San Francisco Department of Environment, December 2002.

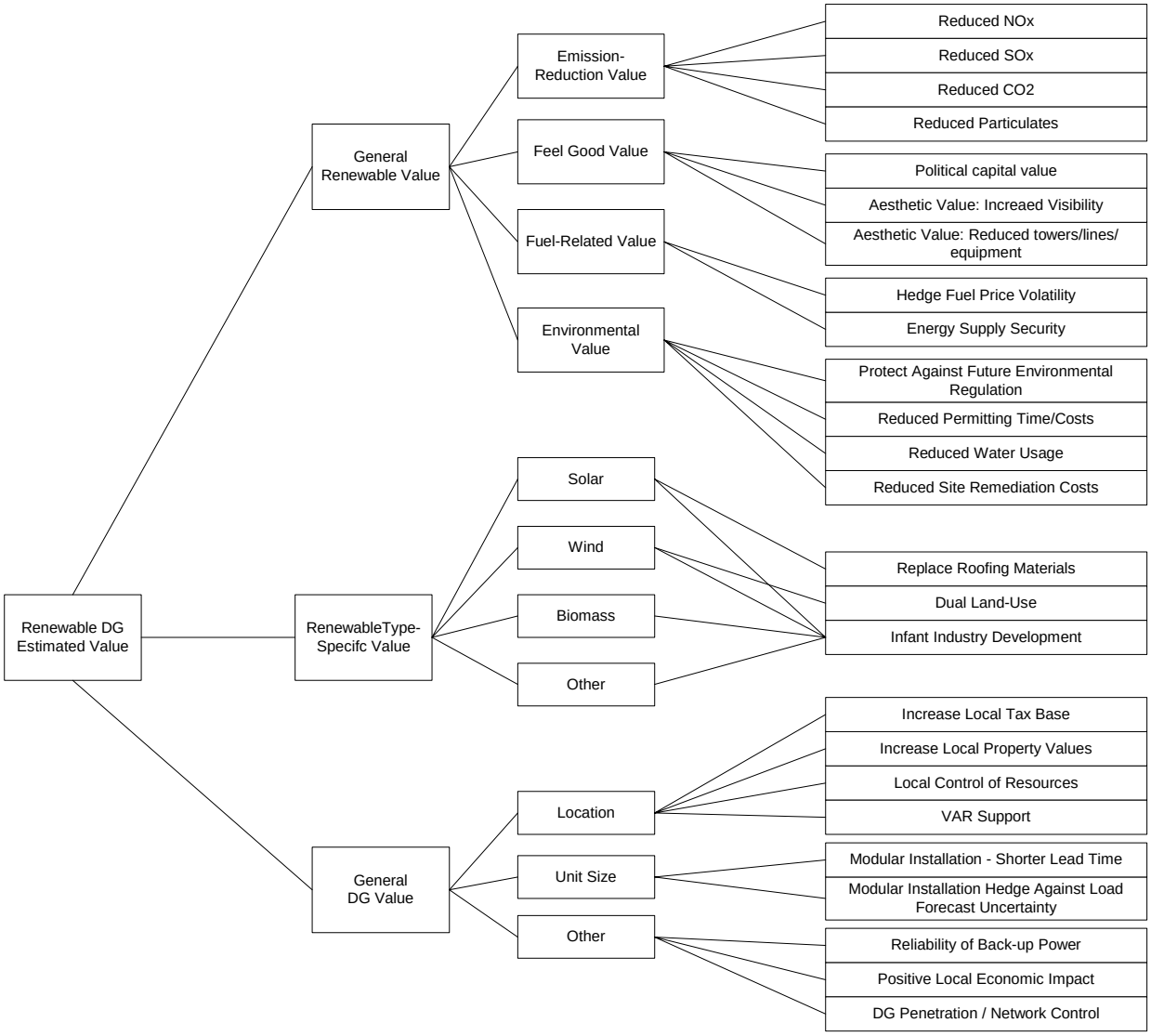

Figure 15: Indirect benefits of RDG

While NOx and particulate mitigation costs are assumed to be embedded in the market prices that make up the early years of our avoided cost forecast, they are not part of the Long-Run Marginal Costs (LRMC) that make up the latter years of the forecast and therefore would need to be added in as indirect benefits.

As mentioned above, the elements in Figure 15 may be weighed against the results of the benefit/cost analysis to help guide decision-making. For example, if the benefit-cost analysis results in greater costs than benefits for a particular type of RDG being evaluated, decision makers may wish to consider whether the indirect benefits have enough value to close the gap. The size of this gap is estimated for each technology and provided in the economic screening results section.

2.4. Results of Economic Screening Analysis

We calculated the cost-effectiveness of each of the RDG alternatives according to the methodology described above. We compared lifecycle benefits and costs for each of the applicable tests on an NPV basis. A benefit/cost (B/C) ratio greater than 1.0 indicates that the alternative has a lifecycle benefit greater than its lifecycle cost and would therefore pass our initial economic screen.

Results are summarized in Table 17. Looking at this table, one can quickly see which RDG technologies are cost-effective based on direct costs and benefits as well as identify which other technologies may be close to a B/C ratio of 1.0 and warrant further evaluation. We have highlighted those technologies with a TRC B/C ratio greater than 1.0, and all the B/C ratios greater than 1.0 are shown in bold type. The Ratepayer Impact Measure (RIM) is calculated assuming the RDG is owned by the customer, while the UCT is always calculated assuming utility ownership of the project. We evaluate the UCT in this manner because the UCT perspective under customer-ownership is not very revealing, since the utility enjoys the avoided cost savings without any of the ownership costs and the B/C ratio is always infinitely positive (in the absence of utility-paid incentives or other program costs).

Table 17: Results of SFPUC RDG screening, under base-case assumptions

	TRC Cost Test	Participant (Customer or Merchant)	RIM Test (Customer Owned)	UCT Test (Utility Owned)
Biogas - 10kW PEM Fuel Cell	0.42	0.71	0.39	0.28
Biogas - 10kW PEM Fuel Cell CHP	0.51	0.88	0.39	0.36
Biogas - 100kW SOFC Fuel Cell	0.61	**1.04**	0.39	0.40
Biogas - 100kW SOFC Fuel Cell CHP	0.71	**1.21**	0.39	0.49
Biogas - 200kW PAFC Fuel Cell	0.50	0.86	0.39	0.34
Biogas - 200kW PAFC Fuel Cell CHP	0.62	**1.07**	0.39	0.44
Biogas - 200kW PEM Fuel Cell	0.53	0.91	0.39	0.35
Biogas - 200kW PEM Fuel Cell CHP	0.70	**1.19**	0.39	0.48
Biogas - 250kW MCFC Fuel Cell	0.48	0.82	0.39	0.33
Biogas - 250kW MCFC Fuel Cell CHP	0.53	0.91	0.39	0.37
Biogas - 30 kW Microturbine	0.23	0.34	0.46	0.17
Biogas - 30 kW Microturbine w/ CHP	0.84	**1.44**	0.39	0.57
Biogas - 500 kW Gas Recip	0.43	0.62	0.46	0.30
Biogas - 800kW Gas Recip	0.55	0.81	0.46	0.38
Biogas - 800kW Gas Recip w/CHP	**1.41**	**2.42**	0.39	0.89
Biogas - 3MW Gas Recip	0.58	0.85	0.46	0.41
Biogas - 3MW Gas Recip w/CHP	**1.45**	**2.48**	0.39	0.90
Biogas - 5MW Gas Recip	0.59	0.86	0.46	0.42
Biogas - MSW Gassification	0.51	0.39	0.00	0.58
Biogas - 5kW Gas Engine	0.28	0.40	0.46	0.21
Biogas - 15kW Gas Engine	0.38	0.56	0.46	0.28
Biodiesel - 500kW	0.78	**1.08**	0.46	0.48
Solar - PV-5 kW	0.28	0.26	0.60	0.24
Solar - PV-50 kW	0.37	0.43	0.46	0.31
Solar - PV-100 kW	0.37	0.43	0.46	0.31
Solar - 25 kW Concentrating Sterling	0.20	0.18	0.00	0.35
Wind - Bergey WD -10kW	0.17	0.27	0.42	0.14
Wind - 750 kW Turbine	0.49	0.49	0.00	0.86
Wind - 1.5 MW Turbine	0.58	0.58	0.00	**1.01**
Sodium Sulfur Battery, 100 kW	0.63	0.81	0.47	0.44
Vanadium Redox Battery, 100 kW	0.41	0.60	0.46	0.32
Polysulfide Bromide Battery, 100 kW	0.42	0.54	0.47	0.29

As can be seen in Table 17, the 800 kW and 3 MW biogas generators with CHP were the only RDG technologies to pass the TRC test, with B/C ratios of 1.41 and 1.45, respectively.

Also of note from Table 17, a number of additional RDG technologies primarily operating with CHP are shown to be cost-effective from the Participant test perspective. These technologies are cost-effective to participants even though they do not pass the TRC test because the bill savings enjoyed by participants exceed the avoided costs benefits measured in the TRC test.

A closer look at selected results is presented in the figures below. The net benefit in these charts may be positive (green) or negative (red) depending on whether benefits exceed costs or vice versa.

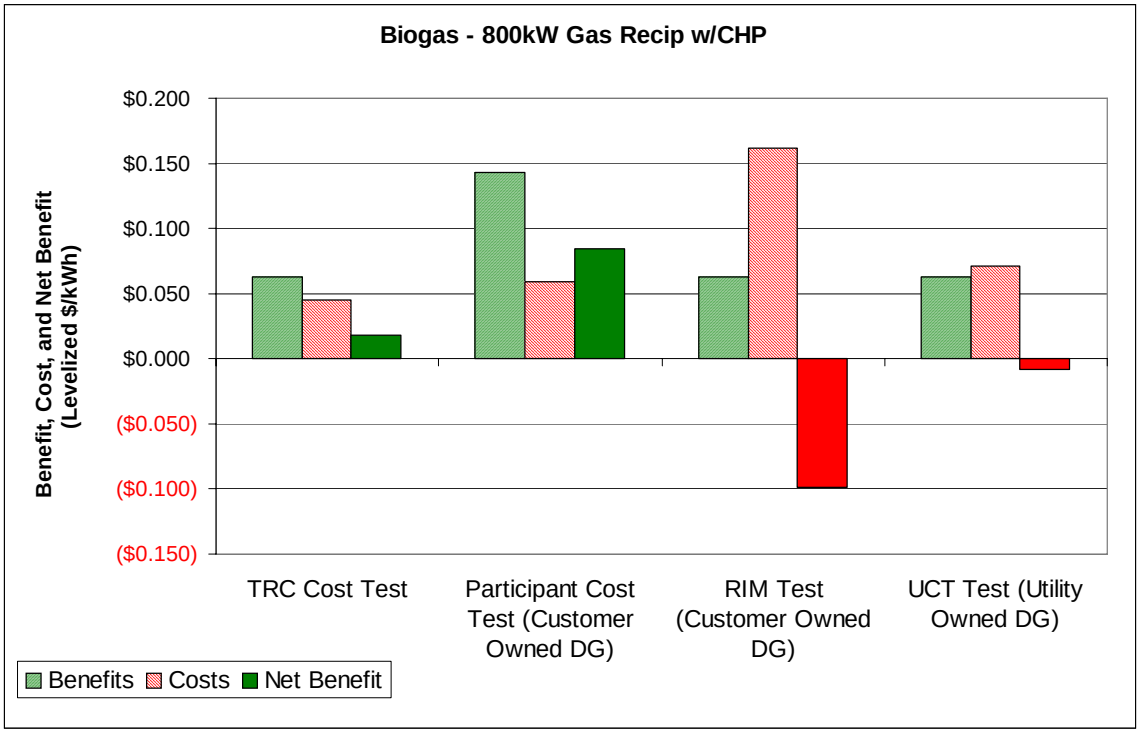

Figure 16: Cost test results for an 800 kW biogas reciprocating engine with CHP

Figure 16 shows that the 800kW CHP-reciprocating engine operating as a baseload unit is cost-effective from both the TRC and the Participant cost test. This combined heat and power (CHP) application would operate on biogas, and the waste heat would displace gas used in a boiler or other application at the RDG site. Using the waste heat significantly improves the RDG technology's economics. Looking at the TRC perspective, which is essentially the summation of the Participant and RIM perspectives, this technology is cost-effective, with a B/C ratio of 1.41.

The unit is cost-effective from the participant's point of view because bill savings resulting from the installation exceed the associated costs. From the UCT perspective, the unit is not cost-effective because, although costs are similar to those experienced by the participant, savings are lower since the avoided costs experienced by the utility are lower than rates.

From the RIM test perspective, the savings in avoided generation and transmission costs resulting from the project are outweighed by the lost revenue in reduced customer bills, resulting in B/C ratio of 0.39. Thus, the installation of the unit by a customer would require the utility to raise rates in order to remain whole.

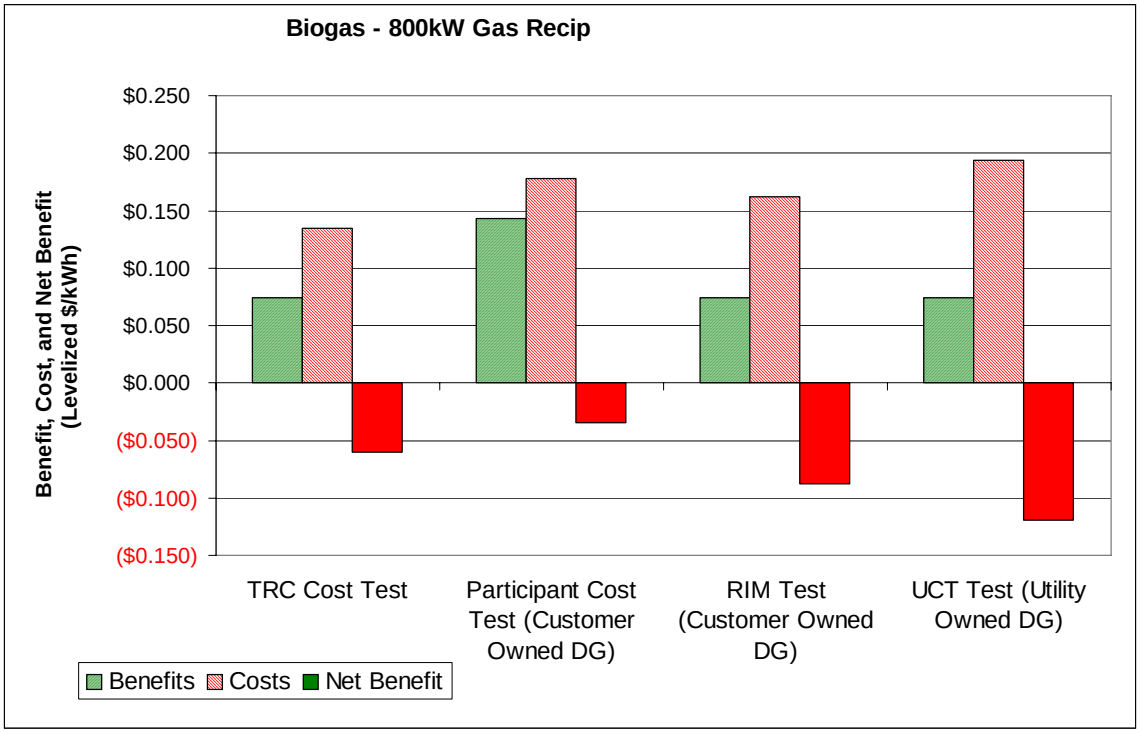

Figure 17: Cost test results for an 800 kW biogas reciprocating engine

Figure 17, which shows the same unit without waste heat recovery, illustrates the importance of CHP to the economics of the 800 kW generator. For this example, the operational characteristics are assumed to be identical to those for the unit with CHP (both are operating as baseload) and the electrical savings are thus identical. But the costs are significantly higher for the non-CHP unit, since the waste heat savings were reflected in a lower net heat rate. Similar results for both the CHP and non-CHP configurations are seen with the 3 MW biogas generator.

A different technology example is shown in Figure 18 which displays the economics of a 100kW polysulfide bromide flow battery from each perspective.[13] The assumed capacity factor of the installation is based on 2000 hours per year (or a 23% capacity factor). From the economic shortfall, the technology does not pay for itself based on the on- and off-peak electric price differential, but with additional benefits of power quality, or environmental improvement, energy storage may be feasible in some locations. The primary driver of this result is the high capital cost of this technology.

[13] This is the battery storage technology used by Regensys.

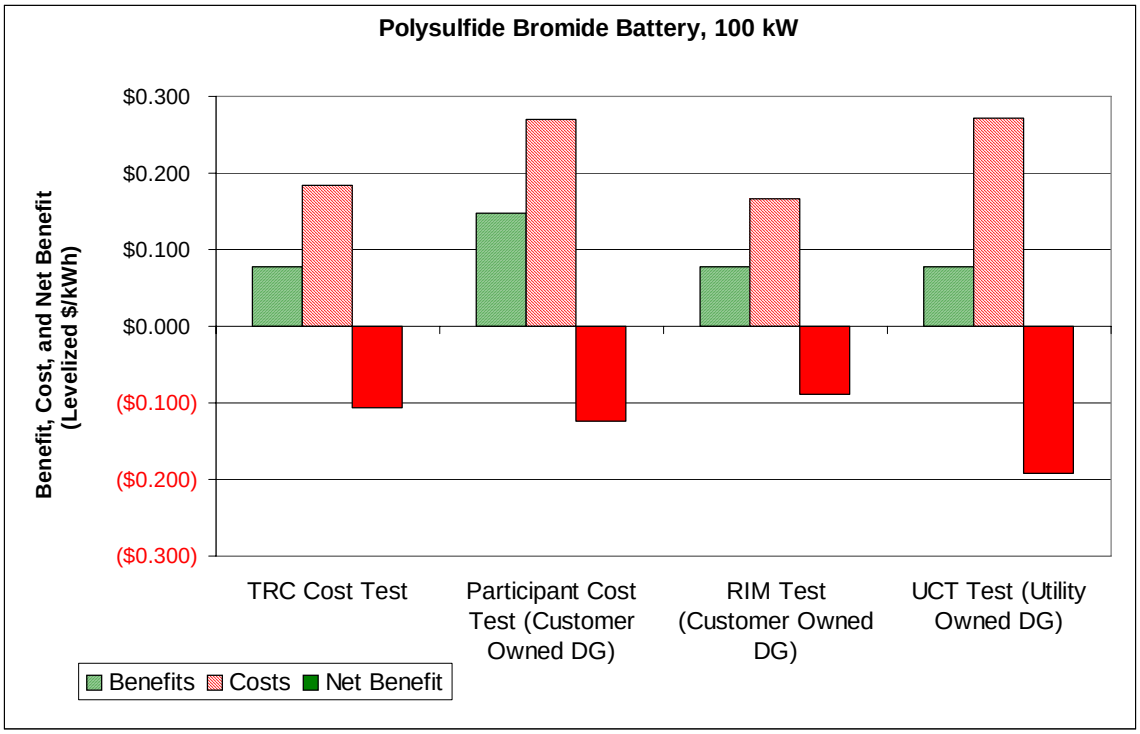

Figure 18: Cost test results for a 100kW Polysulfide Bromide Flow Battery

The results in Figure 19 mirror those in Figure 18. The 100kW of solar PV has very high capital costs relative to the amount of energy produced, which results in a B/C ratio of less than 1.0 from every test perspective. The results in Figure 19 are shown without any financial incentives applied.

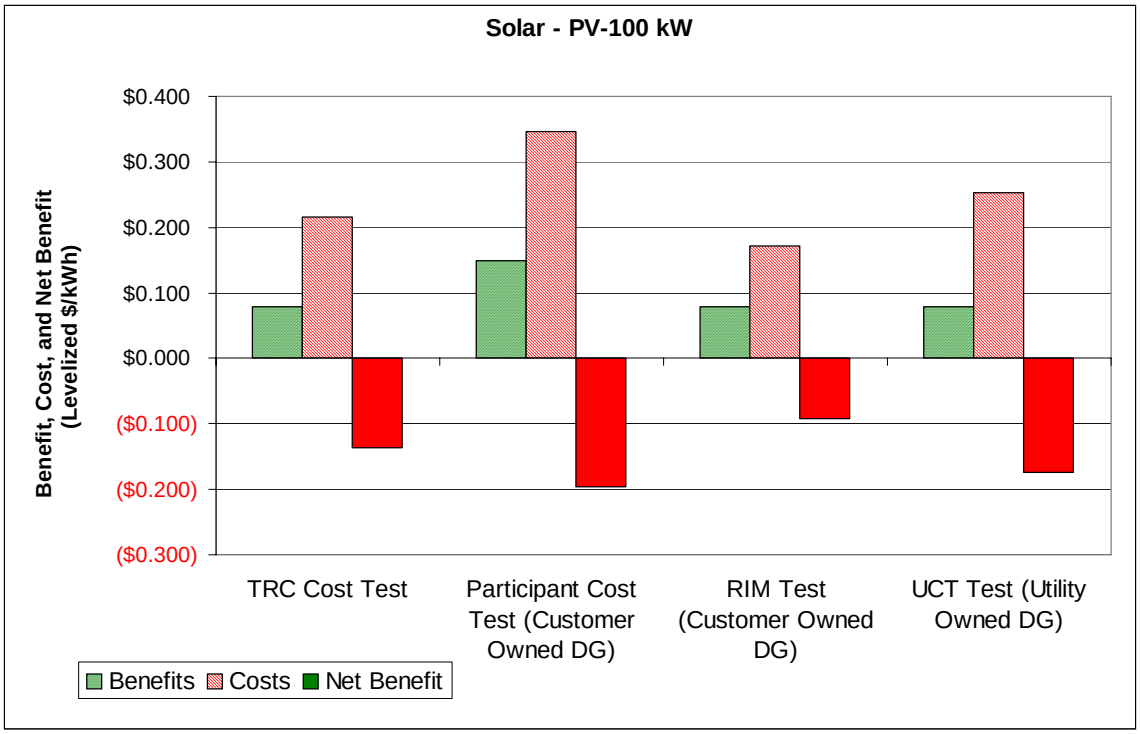

Figure 19: Cost test results for 100kW of Solar PV – No Incentives

Figure 20 shows the results of the same 100kW solar PV array as in Figure 19 but with a 50% capital-cost incentive from the State paid to the customer installing the PV. Note that the TRC test is from the societal perspective, and the State incentive is included as a benefit. While the incentive acts to reduce the shortfall, it is not eliminated in any of the perspectives.

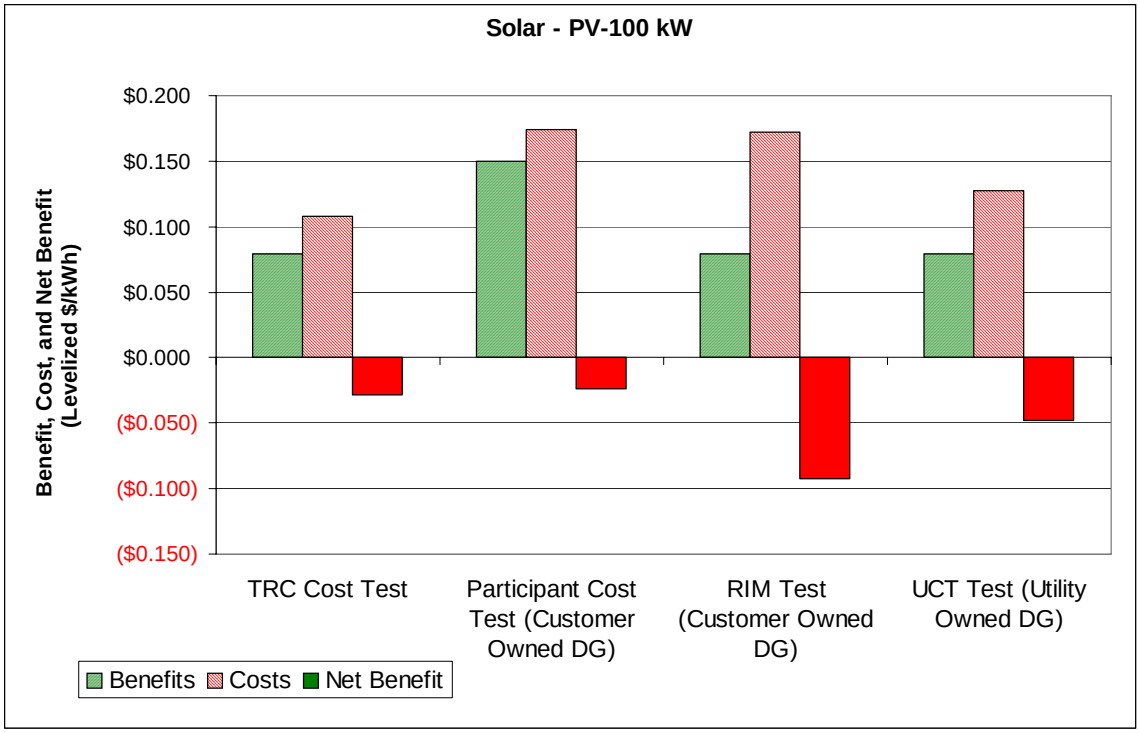

Figure 20: Cost test results for 100kW of Solar PV – With State Incentive

The results for a 750kW wind turbine are shown in Figure 21. This technology does not prove cost effective from any perspective due to its relatively low assumed annual capacity factor of 14% (10% on-peak hours and 4% off-peak).

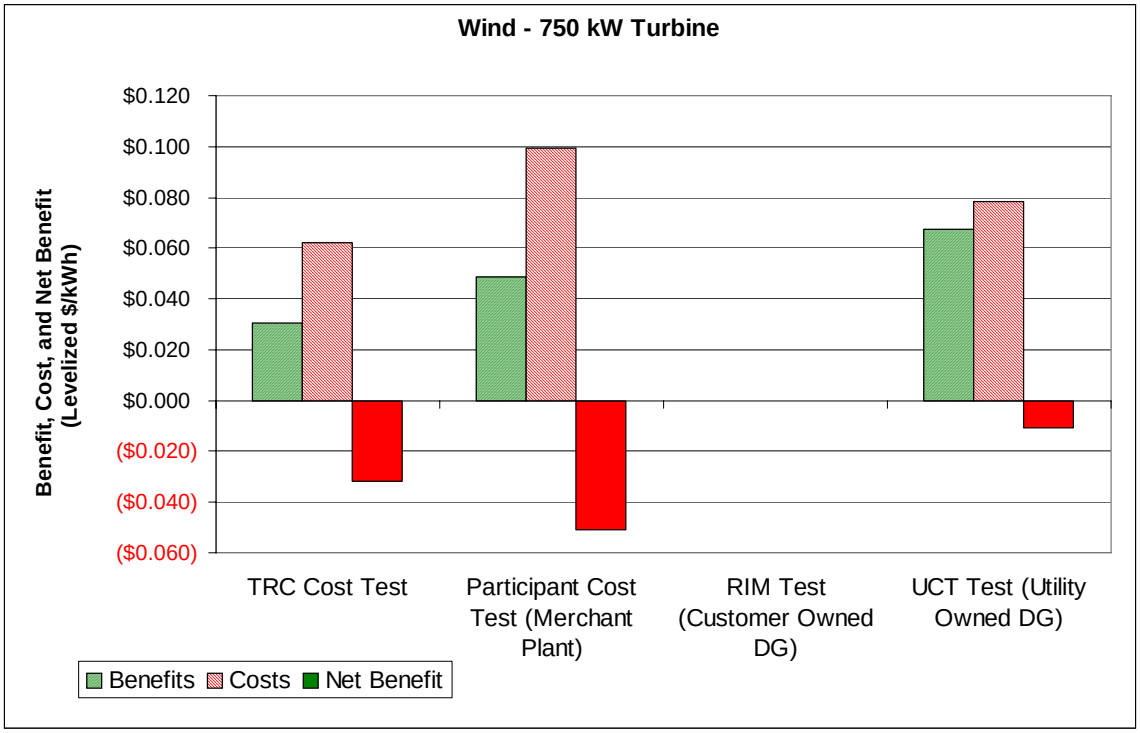

Figure 21: Cost test results for 750kW Wind Turbine (14% capacity factor)

To test the economics of a better wind site, we also evalutated industry rule-of-thumb for an economic 'break-even' at a wind site is a wind resource that yields at least a 30% capacity factor. Figure 22 shows the economics of a 750kW wind turbine at 30% annual capacity factor. These results show that from the Participant perspective the technology is cost-effective by a small margin at this capacity factor. However, because the financing cost for a municipal project is much lower (an assumed 3.95% vs. 12.5% for a merchant plant project), a 30% capacity factor wind site is very cost-effective from the UCT perspective. The SFPUC is currently monitoring the wind resource near the HPNS and the results of the monitoring study would yield a closer estimate of the actual expected annual capacity factor that could be achieved locally. Additional sensitivity testing of the wind capacity factor is shown in the Uncertainty Analysis chapter.

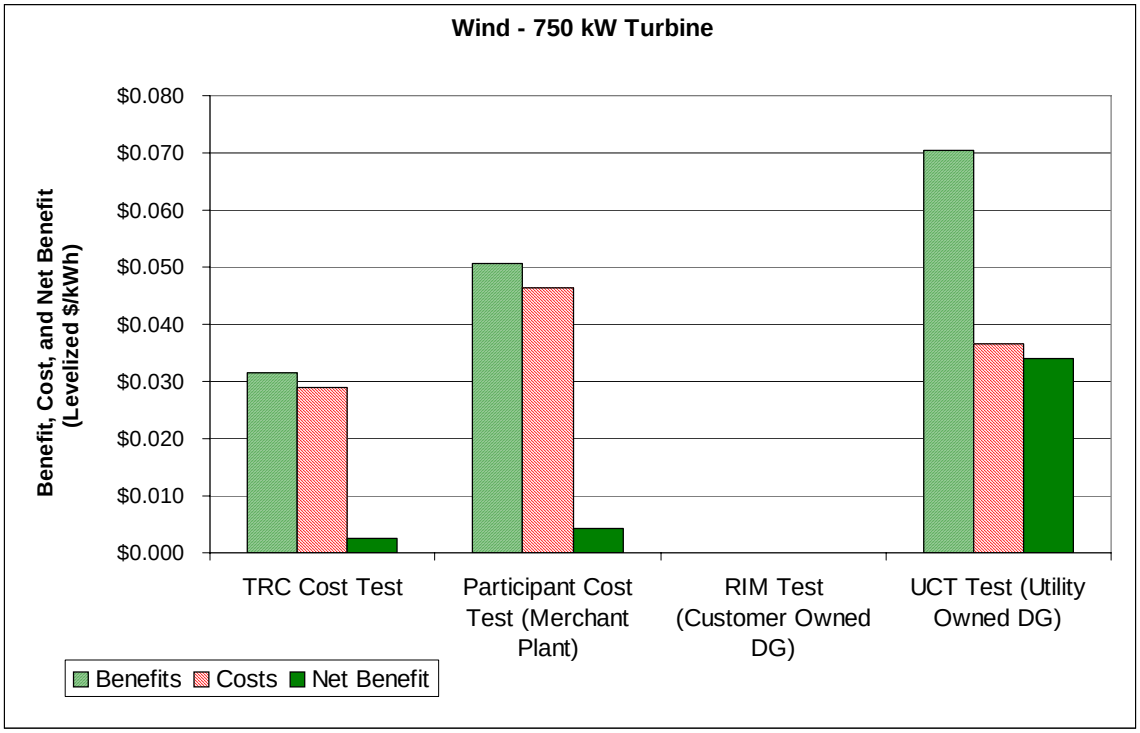

Figure 22: Cost test results for 750kW Wind Turbine (30% capacity factor)

2.5. Economic Screening Conclusions

Referring back to Table 17, under Base Case assumptions, only two of the technologies tested were cost-effective under the TRC test. Both of these are relatively large generators which rely on an effective CHP installation to become cost-effective. These results illustrate the difficulty of finding cost-effective RDG applications in most municipal utility territories.

Clearly if a measure passes all the economic screening tests, it is an excellent candidate for action – assuming a suitable installation site can be found. But what about measures that pass some tests but not others?

For example, the 800kW biogas unit in Figure 16 passes both the TRC and Participant test but by a small margin, does not pass the UCT perspective. However, under certain scenarios tested in our Uncertainty Analysis, this technology does pass the UCT test. So an important consideration in reviewing RDG technologies is how robust the base case results are to changes in the key input assumptions. This issue is addressed in detail in the Uncertainty Analysis chapter.

Another consideration is how indirect benefits are valued. It may be possible to make an even stronger case for the cost-effectiveness of the technology if it meets some of the established energy goals of the SFPUC.

Also most technologies we tested failed the RIM test, indicating that rates would need to rise to keep the utility whole if the technology is installed by a customer. Since PG&E is

assumed to be the utility serving the HPNS, the ultimate impact of increased RDG installations would be to increase rates, and hence bills for all customers other than the owner. The extent to which RDG should be installed at this site is a policy decision that ultimately comes down to the goals and priorities of the SFPUC and other stakeholders. Our goal, in providing multiple test perspectives, is to equip decision makers with the proper tools to understand the trade-offs and ultimately make the best decision for their needs.

If a technology passes some screening tests but not others, the decision ultimately comes down to a management decision based on utility priorities and resource planning goals. The questions answered by each cost test perspective as explained in Table 10 may help characterize the results to a broader audience in terms of operating margin, rates, expected participation, and overall community benefit.

The PV and wind with low capacity factors, for example, have costs that so outweigh benefits from the participant perspective that they are clearly poor economic choices. However, despite their high costs, customers do choose to install solar PV and small wind to meet other objectives, as discussed in the indirect benefits section.

Table 18 shows the $/kWh shortfall for each technology from the TRC perspective. For example, in the case of the 30kW microturbine with CHP, there is a $0.012/kWh direct economic shortfall. Therefore, the value of the indirect benefits would need to be valued at greater than $0.012/kWh for this project to be pursued.

Table 18: Net Benefits of RDG Technologies

	Benefits	Costs	Net Benefits/ (Shortfall)
Biogas - 10kW PEM Fuel Cell	$0.063	$0.152	($0.089)
Biogas - 10kW PEM Fuel Cell CHP	$0.063	$0.124	($0.060)
Biogas - 100kW SOFC Fuel Cell	$0.063	$0.104	($0.041)
Biogas - 100kW SOFC Fuel Cell CHP	$0.063	$0.089	($0.026)
Biogas - 200kW PAFC Fuel Cell	$0.063	$0.127	($0.063)
Biogas - 200kW PAFC Fuel Cell CHP	$0.063	$0.102	($0.038)
Biogas - 200kW PEM Fuel Cell	$0.063	$0.119	($0.056)
Biogas - 200kW PEM Fuel Cell CHP	$0.063	$0.091	($0.028)
Biogas - 250kW MCFC Fuel Cell	$0.063	$0.132	($0.069)
Biogas - 250kW MCFC Fuel Cell CHP	$0.063	$0.119	($0.056)
Biogas - 30 kW Microturbine	$0.074	$0.317	($0.243)
Biogas - 30 kW Microturbine w/ CHP	$0.063	$0.075	($0.012)
Biogas - 500 kW Gas Recip	$0.074	$0.175	($0.100)
Biogas - 800kW Gas Recip	$0.074	$0.134	($0.060)
Biogas - 800kW Gas Recip w/CHP	$0.063	$0.045	$0.018
Biogas - 3MW Gas Recip	$0.074	$0.128	($0.053)
Biogas - 3MW Gas Recip w/CHP	$0.063	$0.044	$0.019
Biogas - 5MW Gas Recip	$0.074	$0.126	($0.052)
Biogas - MSW Gassification	$0.042	$0.081	($0.039)
Biogas - 5kW Gas Engine	$0.074	$0.269	($0.194)
Biogas - 15kW Gas Engine	$0.074	$0.194	($0.120)
Biodiesel - 500kW	$0.073	$0.095	($0.021)
Solar - PV-5 kW	$0.079	$0.282	($0.203)
Solar - PV-50 kW	$0.079	$0.216	($0.137)
Solar - PV-100 kW	$0.079	$0.216	($0.136)
Solar - 25 kW Concentrating Sterling	$0.039	$0.189	($0.150)
Wind - Bergey WD -10kW	$0.068	$0.398	($0.330)
Wind - 750 kW Turbine	$0.030	$0.062	($0.032)
Wind - 1.5 MW Turbine	$0.030	$0.053	($0.022)
Sodium Sulfur Battery, 100 kW	$0.078	$0.124	($0.046)
Vanadium Redox Battery, 100 kW	$0.074	$0.180	($0.105)
Polysulfide Bromide Battery, 100 kW	$0.078	$0.184	($0.106)

Finally, it is important to note that if a technology is cost-effective, as the two biogas CHP technologies are in this analysis, it would be economically-beneficial to install as much of this technology as local distribution system requirements allow.

3.0 Engineering Screening Analysis

This section describes engineering screens performed on the distribution system for the SF PUC HPNS redevelopment to estimate the feasibility of accommodating distributed generation and the potential value of that generation to the benefit of the power delivery system. A particular emphasis was given to renewable technologies.

The existing 12 kV service to the HPNS consists of an overhead line from the nearby Hunters Point power plant substation. The current-carrying capability of this line is assumed to be 8 MW, yielding approximately 8.3 MVA power delivery capacity. It is also assumed that any significant loads now served from the incoming 12 kV feeder will be served from other feeders in the future, allowing the full capacity of the line to be used for meeting the loads on the HPNS.

The HPNS redevelopment comprises four parcels named A, B, C, and D. The first phase of development calls for the replacement of the existing overhead distribution feeders on Hunters Point with an underground cable system on these four parcels. Existing loads in the development area are to be reconnected so that they will be served from the new feeders. Partial development of Parcel A is also part of Phase 1. The second part of the Phase 1 development, Phase 1b, is assumed to be the full development of parcels A and B.

Phase 2 refers to the development of Parcel C, and Phase 3 refers to the development of Parcel D. The peak loads for each parcel are shown in Table 19. These figures were derived from the load forecast study by Newcomb Anderson Associates and modified to account for energy efficient features proposed for the housing units at Hunters Point.

Table 19: Summary of Loading and Minimum Required DG Capacities for Each Phase of the Hunters Point Development

Phase	Parcels	Peak Load (kW)	Min. Req'd kW	Min. Req'd kvar
1a	A	4522	0	0
1b	A+B	9119	1805	1573
2	A+B+C	20667	12918	8223
3	A+B+C+D	38441	30856	18266

Voltage regulation issues appear manageable for Phase 1 because the distances involved are relatively short. However, once the development extends beyond this to Phases 2 and 3, careful attention will have to be given to such engineering issues as voltage regulation and protection. The system makes a transition from a state where the utility source is dominant to one where the power supply in the development becomes dominant at certain times. At the higher load levels, management of the distribution

system on Hunters Point will be similar to that of managing a microgrid that is isolated from the utility system.

The solar PV generation specified for the development as well as other types of renewable generation come with limited ability to produce reactive power (VARs). This becomes a significant issue once the development gets near the end of Phase 1 and then on into Phases 2 and 3. Because the distances involved are relatively short, our simulations of determining VAR requirements by local intelligence only (i.e., monitoring the voltage) suggested that strategy might be unreliable. It is our conclusion that some sort of energy management system will have to be established along with the development to manage the voltage regulation and keep the loading on the incoming 12 kV line within limits.

The energy management system will also have to be capable of controlling the dispatchable generation for Phases 2 and 3. It will be required to supervise the restoration of power after a fault in which all the generation has disconnected to allow the fault to clear. When the load greatly exceeds the capacity of the incoming line, load restoration will have to take place in stages. It will not be possible to turn everything back on all at once.

The solar PV units are assumed not to contribute to short circuits on the distribution system. Therefore, no changes to the existing utility protective relaying scheme should be required through Phases 1a and 1b. However, any type of rotating machine generation added to meet Watt and VAR dispatching requirements of later phases will certainly contribute significantly to fault currents. This often requires modification of the traditional utility relaying schemes to successfully clear faults and restore the system after a fault.

The engineering analysis was performed in three steps:

1. Determine the area power flow characteristics for each phase.

2. Perform a DG siting analysis for each phase along with other possible solutions for meeting the load requirements at Hunters Point. While 'optimal' locations were identified, there is actually little difference between any of the locations on Hunters Point. The primary concern for the higher loading phases will simply be to site power generation somewhere within the development.

3. Perform operational feasibility analysis for proposed cases. This was done by modeling solar PV generation near the proposed development sites for the residential and commercial parts of Phases 1 and 2. For each phase of the development, the amount of Watt and VAR generation required to support the system was determined by assuming a hypothetical dispatchable generator at the location where the new 12 kV feeders originate on Hunters Point and are connected to the incoming utility feed. The generator was modeled as being dispatched by a simple deadband controller that keeps the loading on the incoming feed no greater than approximately 8 MW and 3.3 MVAR.

The impact on annual energy and capacity values are evaluated in the Reliability Analysis chapter.

3.1. Description of Development Phases

The redevelopment of the HPNS studied here consists of four parcels of land referred to as parcels A, B, C, and D. The first phase of development will occur on Parcel A. Subsequent phases will continue the development on Parcel A and the development of the other parcels.

Beginning at the entrance to the Hunters Point development, a new underground feeder system is proposed. Twelve underground feeders will branch out from this point, which could serve as the site for a new substation at some time during the development process. These feeders will replace the existing overhead lines that serve the HPNS. Initially, the feeders will be served from a single 12 kV line from the existing Hunters Point substation. The geographic topology of these feeders relative to the existing Hunter's Point substation is illustrated in Figure 23. Each feeder is shown in a different color. A computer model was developed from the Newcomb Anderson Associates Overall Site Plan[14].

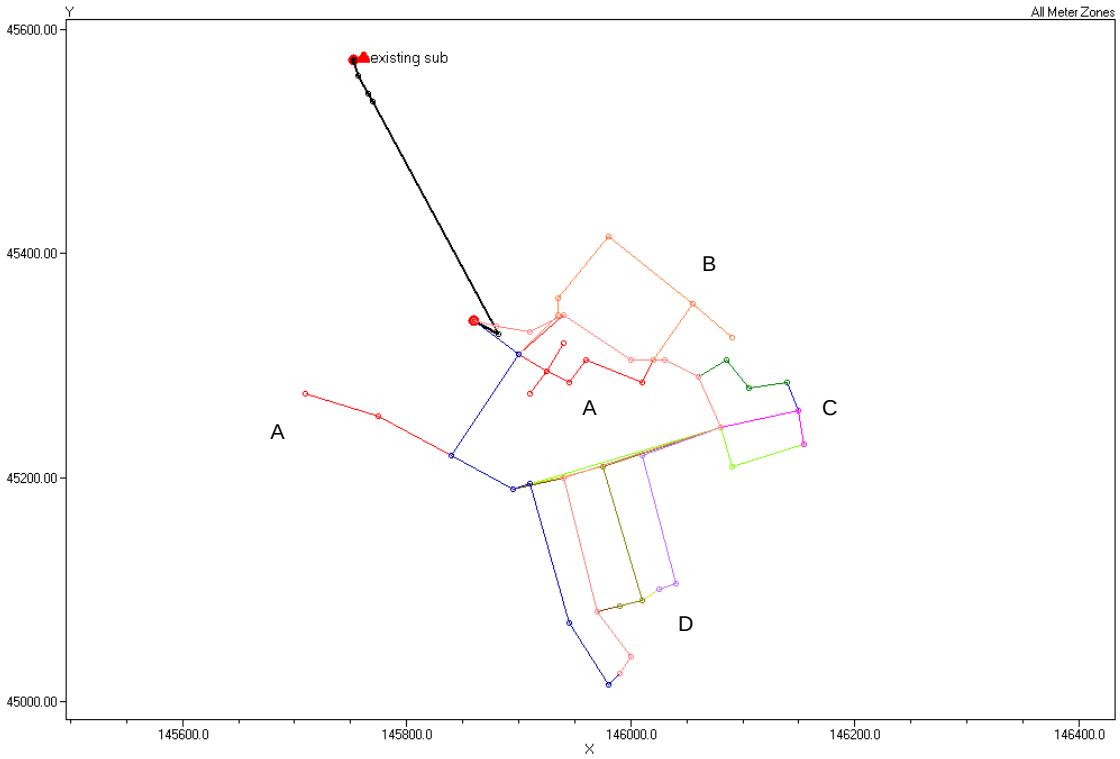

Figure 23: Locations of Hunters Point Underground Feeders

[14] Newcomb Anderson Associates, Overall Site Plan, Hunters Point Switchyard, Dwg E-2.2, October 13, 2003.

The peak load projected for each parcel is shown in Table 20 along with the total for each phase of the project. These figures were derived from the load forecast study by Newcomb Anderson Associates and modified to account for the energy efficient features proposed for the housing units at Hunters Point.[15]

Table 20: Loading Projected for Each Parcel

Parcel	Peak Load	Total Accumulated (kW)
A	4522 kW	4522
B	4597 kW	9119
C	11546 kW	20665
D	17774 kW	38439

The incoming line from the existing Hunter's Point station has an assumed capacity of approximately 8.6 MVA (8 MW, 3.3 MVAR). This is sufficient to serve the first part of Phase 1 development (Parcel A). However, additional supply capacity will be required to meet the projected peak demand for all remaining phases.

The HPNS redevelopment is proposed to take place in three major phases. The nomenclature used here for the various phases is as follows:

Phase 1a = Parcel A

Phase 1b = Parcels A + B

Phase 2 = Phase 1 + Parcel C

Phase 3 = Phase 2 + Parcel D

[15] Newcomb Anderson Associates, HPS Electric Service Evaluation, Task 5 Deliverable – Technical Memorandum for Preliminary Load Forecasts, Letter to Mr. Sam Larano, Hetch Hetchy Water and Power, August 5, 2003.

3.2. Description of Analysis

This section describes the work performed to gain an understanding of the essential electrical characteristics of the system and to evaluate the feasibility of proposed distributed generation (DG) alternatives from an engineering perspective. Prior to this analysis, models of the proposed distribution system have been constructed in Electrotek's Distribution System Simulator (DSS). This tool is used to perform the analysis described herein.

The steps in this analysis are as follows:

1. Generate graphics of the power flow to rapidly gain an understanding of the system and begin to understand where there might be some opportunities for DG.

2. Perform a siting analysis for various sizes of generation to determine where the most benefits to the system can be obtained.

3. Evaluate other possible solutions for meeting the load at Hunters Point.

4. Evaluate proposed distributed generator schemes for operational feasibility with respect to losses, voltage regulation, and impact on overcurrent protection.

3.2.1. Power Flow Characteristics

The next three figures depict the power flow at peak load for the main three build out phases. It is assumed for each of these cases that the power can be delivered from the existing substation, although that will be impractical past Phase I without some reinforcement of the existing lines bringing power from the substation to the Shipyard.

Figure 24 illustrates the feeder flows for the peak load case of Phase 1a (Parcel A). The thicknesses of the lines in this plot are in proportion to the power flowing in the feeders.

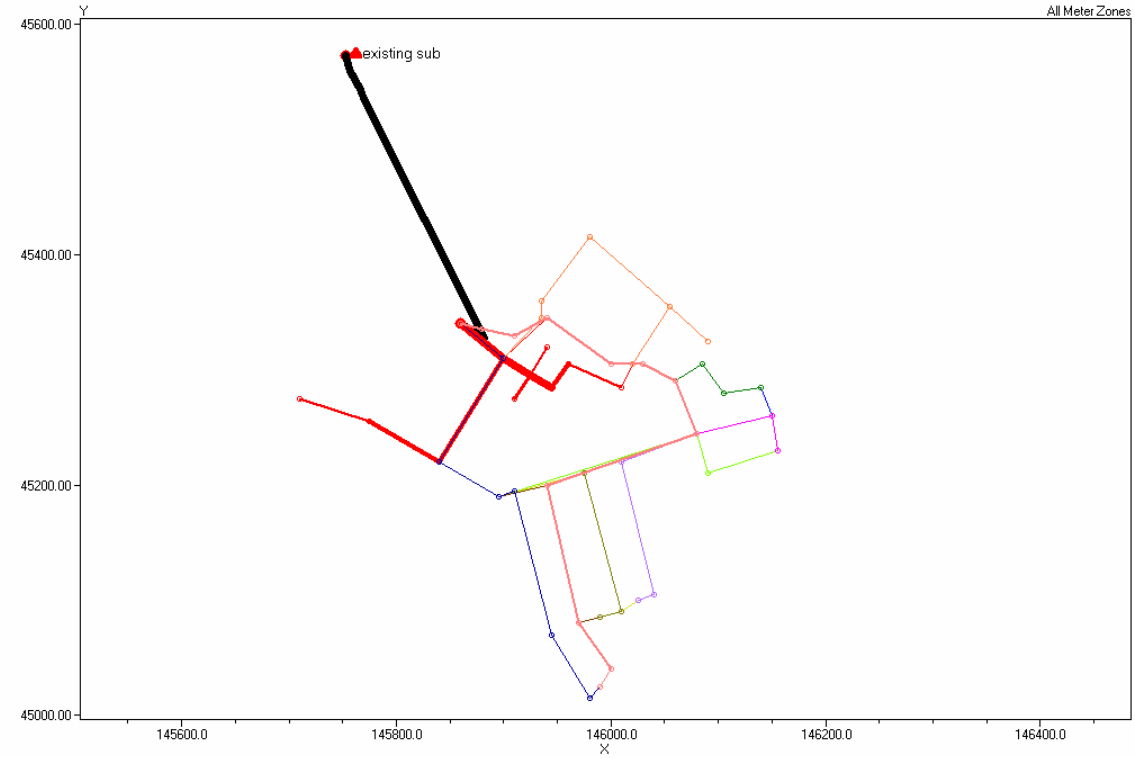

Figure 24: Peak Load Flow Diagram for Phase 1a

Figure 25 illustrates the feeder flows for the peak load case of Phase 1b (full development of parcels A and B). Again, the thicknesses of the lines in this plot are in proportion to the power flowing in the feeders. The main difference between this plot and the previous one is the increased power delivered to the northern part of the area.

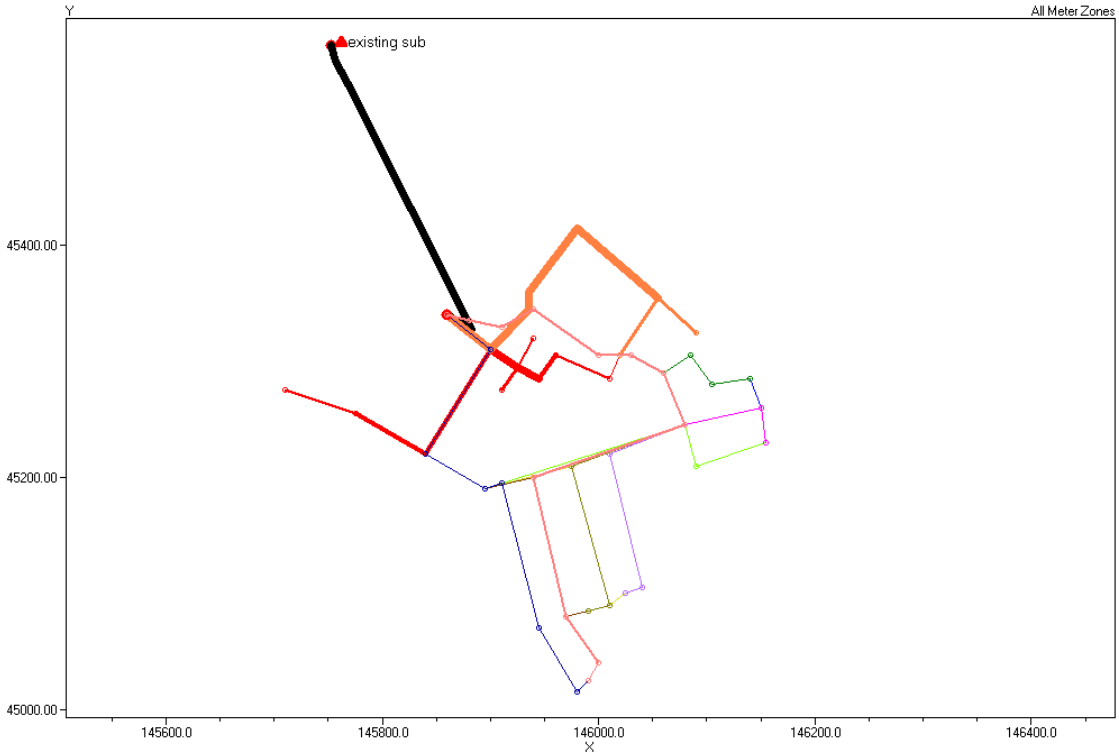

Figure 25: Peak Load Flow Diagram for Phase 1b

Figure 26 illustrates the feeder flows for the peak load case of the last phase (full development of parcels A, B, C, and D). The assumed loads for each parcel are distributed nearly equally among the feeders.

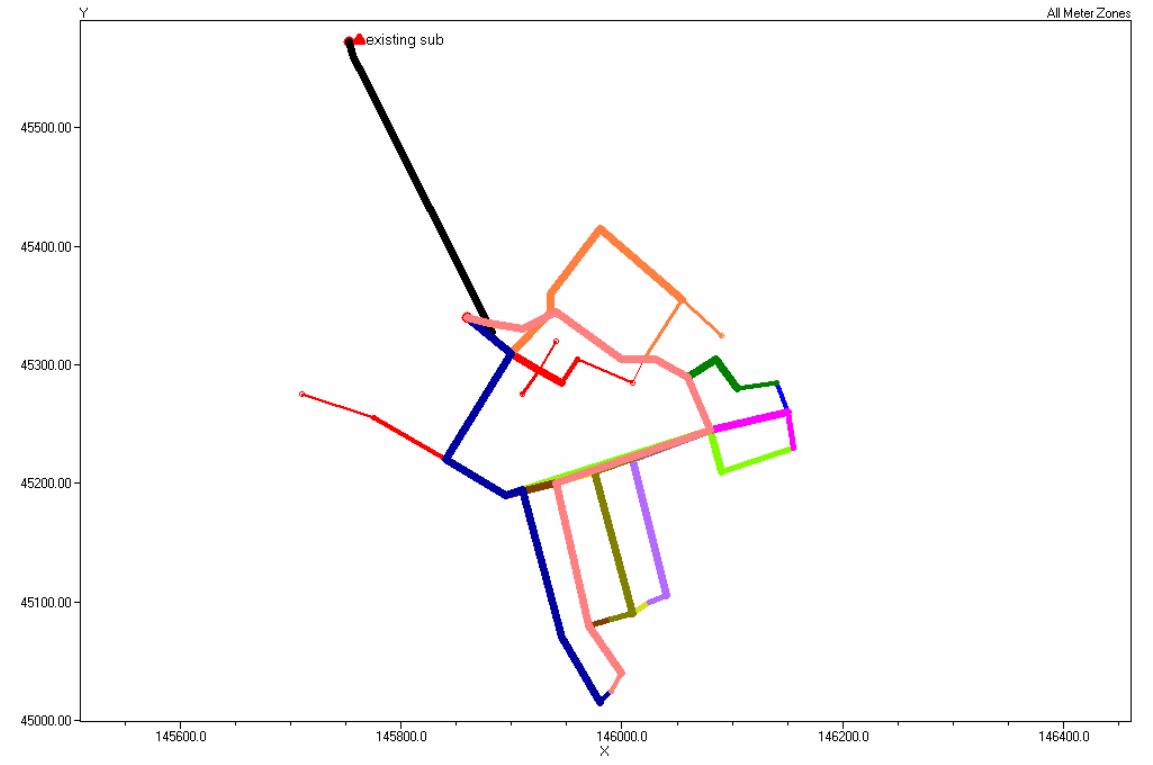

Figure 26: Peak Load Flow Diagram for Final Phase (Phase 3) – All Parcels

3.2.2. Phase 1a (Parcel A)

The base annual peak load profile for Phase 1a, which is the development of Parcel A, is shown in Figure 27. This is similar to other residential/commercial locations along the San Francisco Bay that have minimal air conditioning (cooling) load in the summer. The peak demand is expected in the early evening hours in the winter. A Christmas peak is also assumed. With conservation methods that might be employed, this load profile can be leveled.

This figure shows the base profile without the solar photovoltaic (PV) generation that is to be built into each structure in the development. The concept behind this analysis is to start with the expected load demand and then add local generation and storage effects.

With the projected 1.2 kW of solar PV per housing unit, the annual peak load profile becomes as shown in Figure 28. There would be a total of 1800 kW of PV generation. The solar PV generation clearly takes a large chunk out of the mid-day summer peak loading on the incoming 12 kV line. It also assists on the late morning peak in the winter months. However, it will not necessarily contribute to reducing the yearly peak that occurs in the early evening fall and winter hours.

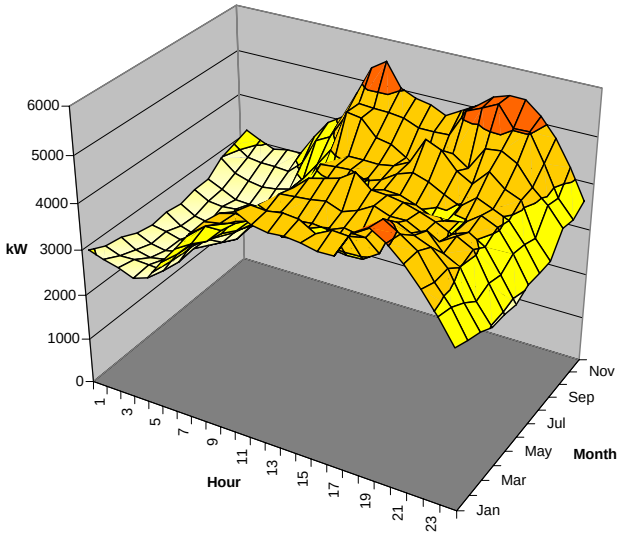

Figure 27: Phase 1a Peak Load Profile (no PV)

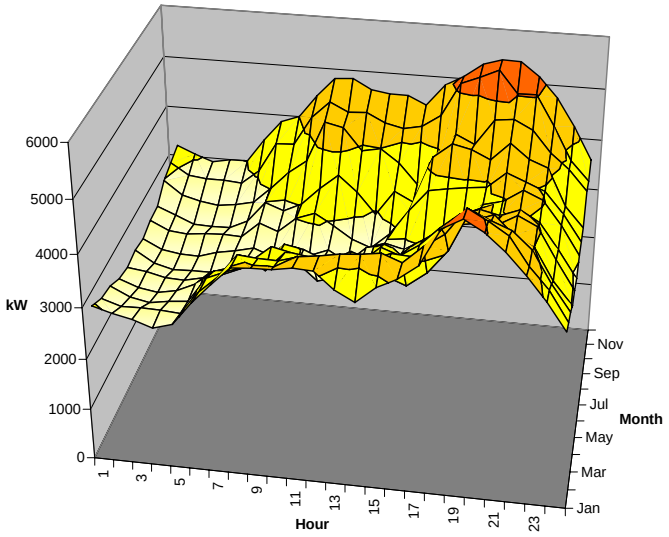

Figure 28: Phase 1a Peak Load Profile (with 1800 kW PV Generation)

The energy and peak power needs of Phase 1a can be met with the existing feeder from Hunters Point substation.

3.2.3. Phase 1b (Parcels A and B)

When Parcel B is developed in Phase 1b, the peak power needs of Hunters Point can no longer be met with the existing 12 kV feeder limited to 8 MW or 8.6 MVA. Figure 29 shows the annual peak load profile for the base demand with no PV generation considered. Figure 30 shows the same case, but including the impact of the PV

generation. At the conclusion of this phase, it is expected there will be a total of 3100 kW of solar PV generation installed.

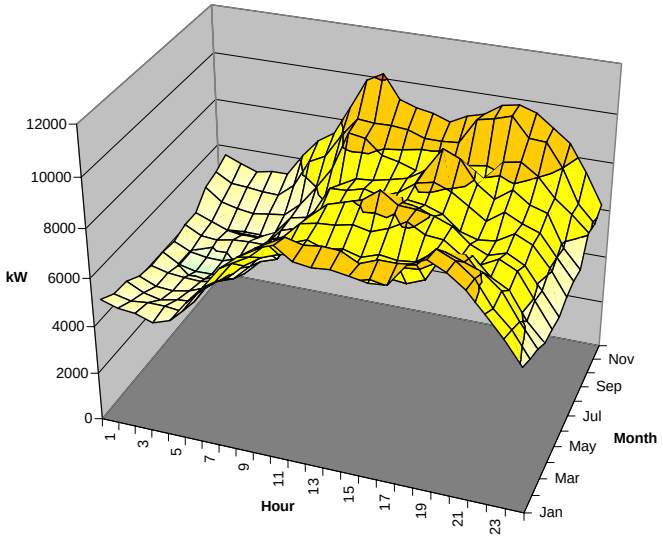

Figure 29: Phase 1b Peak Load Profile (no PV)

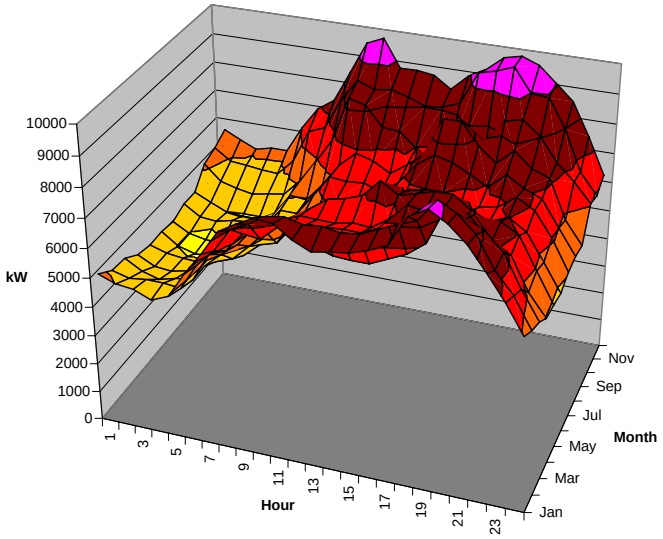

Figure 30: Phase 1b Peak Load Profile (with 3100 kW PV Generation)

For Phase 1b, the early day peak demand is higher than the evening peak due to the increase in commercial development. Considering the residential PV, the early peak

demand on imported power is reduced to approximately the same level as the evening peak. However, the evening peak exceeds the capacity of the single feeder to Hunters Point from the substation. The PV generation is not able to alleviate this demand without some sort of storage.

The feeder supplying Hunters Point would need to carry approximately 500 A, which is approximately 20 percent over its assumed rating of 416 A. The peak shortfall for Phase 1b is 1805 kW and 1570 kVAR (not necessarily coincident). The active power requirement can be easily met with some sort of peaking generation that runs less than 100 hours per year and approximately six hours on peak demand days.

Figure 31 shows the results of an optimal siting analysis for Phase 1b.

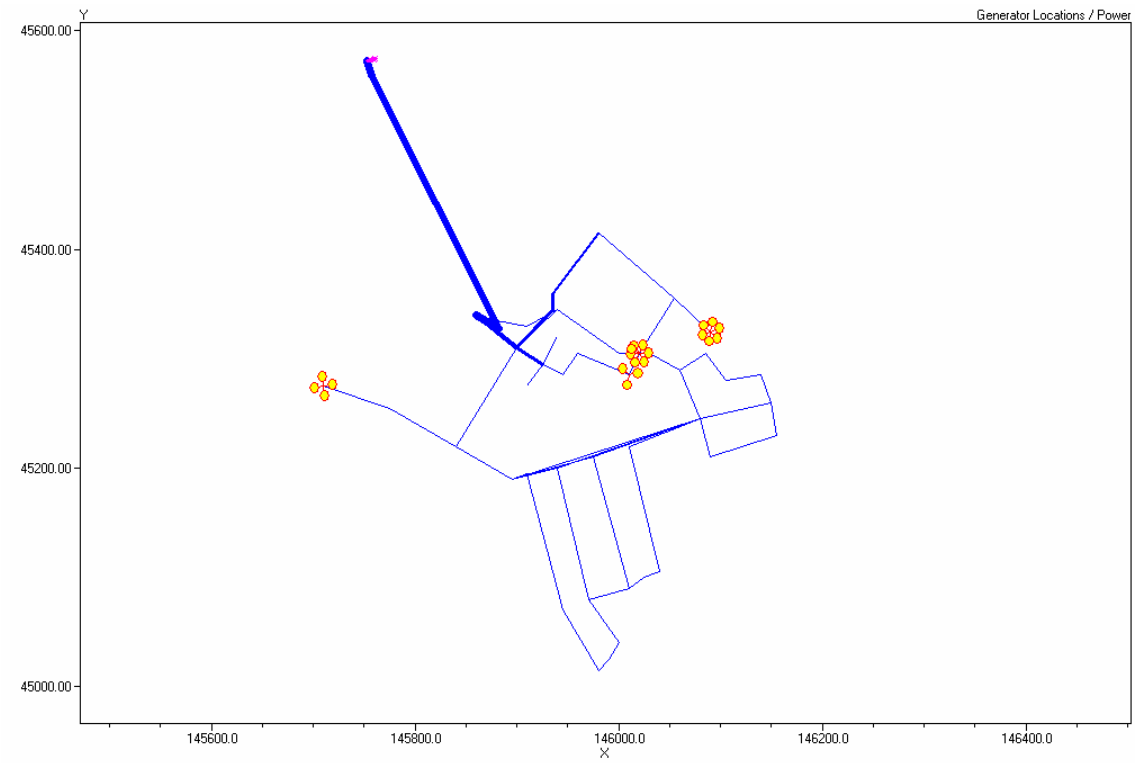

Figure 31: Phase 1b DG Optimal Siting results

The clusters of generators indicate the electrically optimal locations, which tend to be at the ends of the feeders. However, since it is expected to run only a few hours a year, seeking an optimal location for the peaking generation is of less importance than it might be if it were to run most of the year. The main constraint is the incoming line from the substation. A generator placed anywhere on Hunters Point would alleviate the loading on that line. By siting the generation farther out of the feeder, there is a bonus reduction in active and reactive power demand. However, due to the relatively short distances in this situation, there is little significant difference in the locations for electrical considerations. The overriding issue on siting generation will simply be

finding a location where there is room to place it such that it is environmentally acceptable.

Such a peaking generator would likely not be large enough to require changes to the existing utility system. The generation could be implemented with a single 2 –2.5 MW unit or, for more reliability, two 1.5 – 2 MW units. Generator units of this size are readily available. Such a generator would be expected to have minimal interaction issues with the utility protection system if operated in the typical parallel-connected mode. One issue could be the restoration of the system after a fault. Since the peaking generation would be running only during peak load, some coordination may be required to properly sequence the reconnection of loads and generators. All generation, including the solar PV, would have disconnected when the fault occurred.

3.2.4. Phases 2 and 3: Completing the Project

Table 21 shows the minimum amount of dispatchable power required to support the HPNS for the various phases of development. The table lists both the kW and kVAR values required. The values were determined by performing an annual simulation of the system and recording the peak values of power and reactive power output of the generation required to keep the loading on the incoming 12 kV line at, or below, its rating. The output of the solar PV generation was included in the simulation. Thus, the Table 21 represents the additional amount required to supplement the solar PV generation. The greatest requirement would be expected to occur in the winter months when the solar PV generation provides its least assistance.

The power can come from a mixture of generation and storage. Keep in mind that the values shown in Table 21 represent the *minimum* amount of addition power and reactive power resource required. There will have to be somewhat more capacity to produce this power to ensure that this minimum can be met.

No additional resource is required for the first phase (Parcel A only). The demand can be met entirely by the existing 12 kV supply. As the development progresses through Parcel B, the additional requirement can be met with a relatively straightforward peaking generator. However, to advance to the next phase without increasing the capacity available from the existing source, there will have to be at least 13 MW of power supply resource added on Hunters Point. This generation would have to operate 25% of the time. Over 8 MVAR of reactive power capacity will also be required.

If the incoming line could be reconductored to carry 12 MW, or another feeder could be tapped for an additional 4 MW, not only would the installed resource capacity drop by approximately 4 MW, but the amount of time the resource would have to produce power would decrease to less than 9% of the time. This might make it easier to meet the requirement with renewable resources. The reactive power capacity required would also drop, but by a smaller percentage, to 6.6 MVAR.

Table 21: Minimum kW and kvar Supplemental Generation Required on Hunters Point for Each Development Phase

Phase	kW	kvar
1a	0	0
1b	1805	1573
2	12918	8223
3	30856	18266

Over 30 MW of distributed power resource would be required to complete the development according to load projections. This resource would have to produce power over 60% of the time to avoid constructing new feeds from the existing PG&E system. Again, if it were possible to acquire another 4 MW of delivery capability in the lines currently supplying Hunters Point, the power requirement may be dropped by 3900 kW (there are some losses) and the resource would be expected to operate 32% of the time.

3.2.4.1. Dispatching the DG

For Phases 2 and 3, there would be many times when the power resources at the HPNS would be greater than the incoming capacity of incoming line. This is not a situation where one can achieve 'plug-and-play' and let the generators control themselves by local intelligence only. This would be something akin to operating a microgrid and some sort of intelligent control would be required. For the annual simulations, a simple deadband controller monitoring the active and reactive power on the incoming line was used to dispatch the generators (Figure 32). The objective of the controller was to keep the loading on the line to less than 8 MW and 3.3 MVAR with bandwidths of 100 kW or 100 kVAR. If the line loading were to go outside the band, the generation would be dispatched up or down to bring the loading back to center band. (The DG output is assumed to never go below zero.) This method is computationally simple to implement and converges well for performing the annual power flow simulations. Obviously, a more sophisticated controller could be designed that could take into account the availability of the various renewable resources and storage once those technologies are defined.

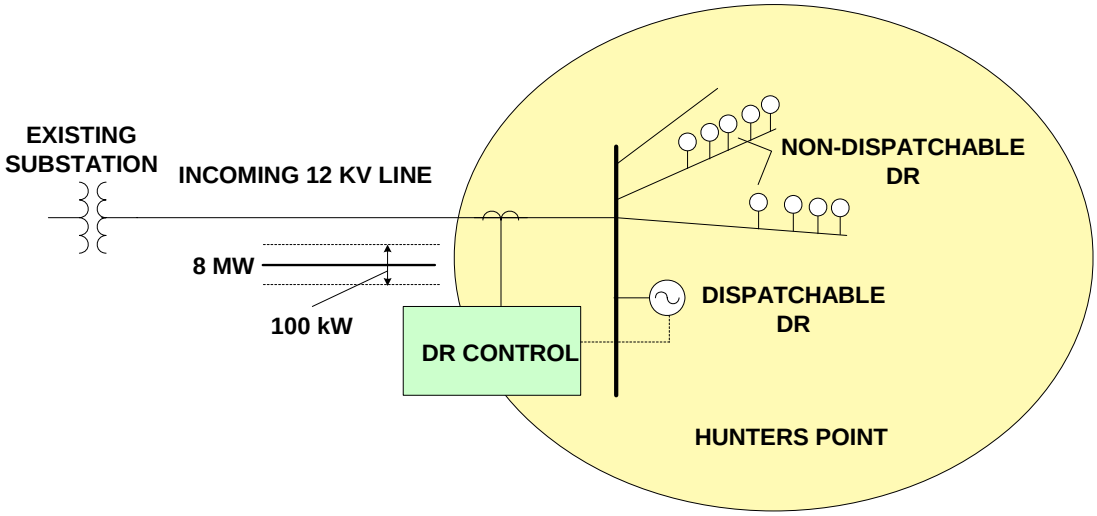

Figure 32: Model used to Determine DG Requirement for Hunters Point Shipyard Redevelopment. Power on Incoming Line Limited to 8 MW by Controlling Dispatchable DG

This simple simulation method quickly reveals the minimum requirements for power and reactive power to keep the incoming line loading within limits at all times.

Example results of using this model are shown in Figure 33 for Phase 1b (parcels A and B). This clearly shows that for this case the dispatchable DG would be required mostly during the winter months and seldom during the summer months. Note that the reactive power (kVAR) requirements do not always coincide with the active power (kW) requirements.

The dispatchable DG is assumed to be lumped at the bus where the new 12 kV feeder cables specified in the Newcomb Anderson Associates report are connected with the incoming 12 kV line. The DG could also be distributed among the various feeders. Because the feeders are relatively short, this wouldn't change the overall result materially as long as no feeders are overloaded with too much generation. The key is simply to have the DG present somewhere on Hunters Point to relieve the loading on the incoming line.

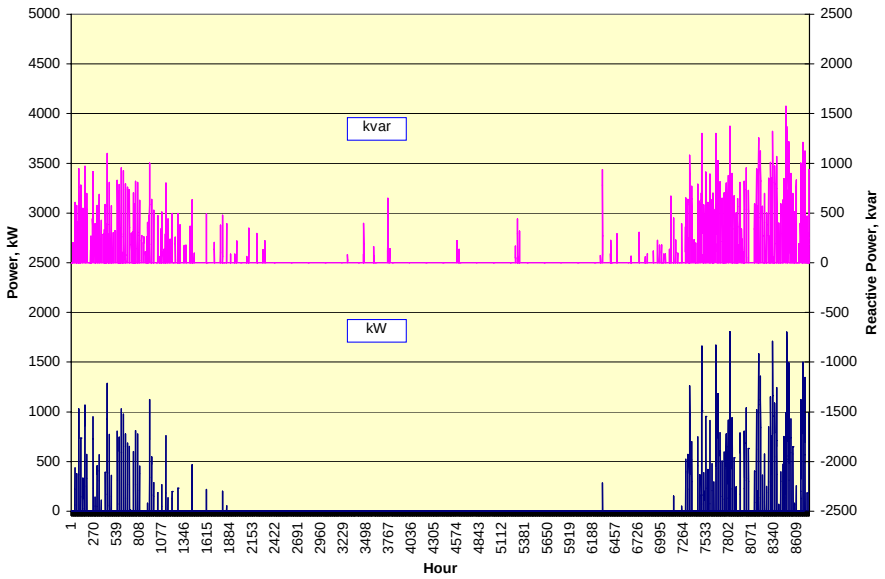

Figure 33: DG kW and kVAR output required for Phase 1b to limit incoming 12 kV line to 8 MW and 3.3 MVAR or less

Figure 34 and Figure 35 show the annual 3-D profile plots corresponding to Figure 33. These show the peak active and reactive power requirements, respectively, at a given hour of day in each month to keep the loading on the line no greater than its rating within the deadband tolerance.

In actual practice, some type of energy management system will have to be established at the HPNS to balance the available resources in real time. This will require dispatchable resources in addition to non-dispatchable resources such as solar PV and wind generation. The energy management system would also be required to supervise the restoration of the system after a fault. This subject is addressed in further detail in the Reliability Analysis chapter.

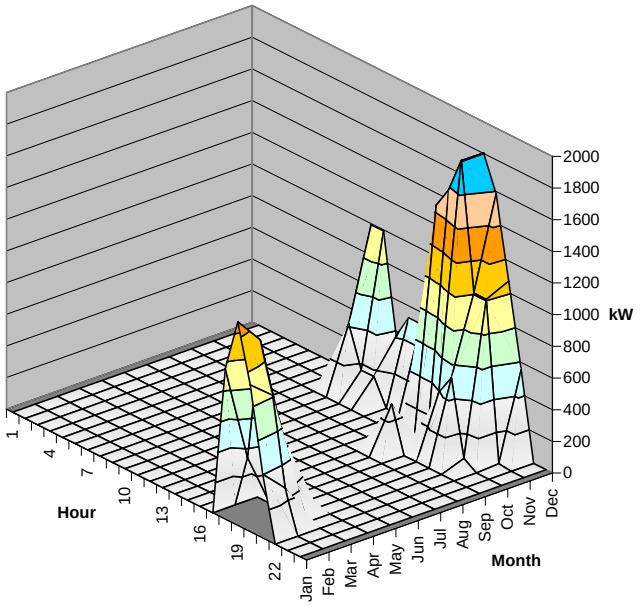

Figure 34: Peak DG Active Power Output Required for Phase 1b

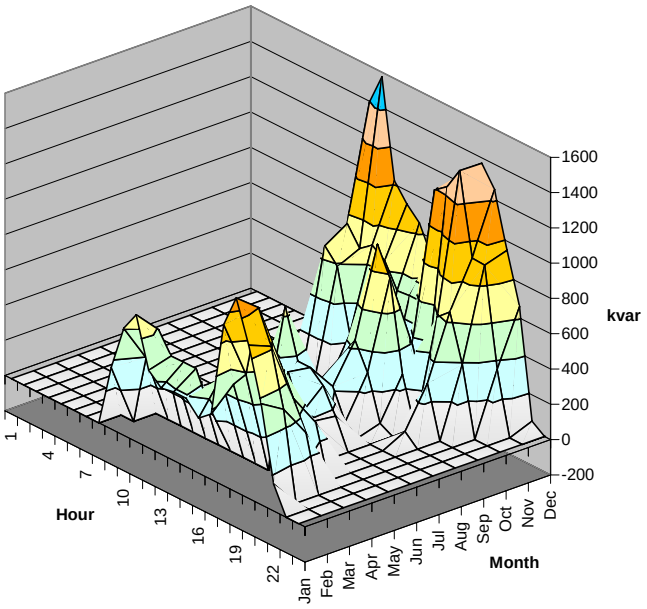

Figure 35: Peak DG Reactive Power Output Required for Phase 1b

The large amounts of generation required for Phases 2 and 3 could contribute significantly to voltage regulation and fault protection coordination issues with the

existing 12 kV distribution system. The simulations assumed fast response from the dispatchable generation and that voltage regulation was smooth. Considerable attention will have to be given to control actions during fault events on the 12 kV feeders at the HPNS and for remote fault events on other parts of the power system. For example, nuisance tripping of DG due to voltage sags on the transmission system is a common problem for parallel operated DG. However, this cannot be tolerated on the proposed HPNS scheme because the stability of the system is so dependent on the generation. Therefore, a substantial portion of the generation must be controlled from a central controller that is able to gather system data from several sources and quickly assess the condition.

4.0 Load and Resource Analysis

The redevelopment plans at the HPNS will result in a significant increase in local demand for electricity. As part of this RDG Assessment, we have conducted a load and resource analysis to determine what load levels will need to be served, when they will occur, and how they can best be met with RDG resources.

In previous sections of this RDG Assessment report, we established the avoided cost values that were then fed into an economic screening of potential resources. In addition to the economic screening, we conducted an engineering siting analysis to determine the best location for RDG to be installed within the HPNS. In this load and resource analysis, we further refine our assessment by combining the results of both the economics and the engineering screening analyses.

In the following sections, we will first explore in greater detail the load patterns and the ability of different RDG technologies to meet the local load requirements. We will then discuss the cost impact of serving each phase of the HPNS development and compare these costs to potential RDG alternative solutions.

An important element of DG assessment is evaluation of the fit between load shapes and DG output. The more coincident the DG-output shape with the load shape, the greater the benefits, particularly in terms of deferring distribution investment. This chapter presents information on the load shapes assumed for the various phases of the HPNS development and the use of DG to supplement the power supply available through PG&E's 12 kV line serving the area.

4.1. Local Area Load Shapes

The load shapes were developed by studying the plans for the development of the HPNS and comparing with load data for another Bay Area community with similar makeup. The loads were modeled by defining a base load for the residential and commercial facilities. The rooftop solar PV generation was then added as negative load following the solar output pattern for the area.

Our load shape analysis tool allows the user to select the year and data subset (system, substation, feeder, or some combination) of interest and view the corresponding load shape. For each hour of each month (e.g. 8:00 – 9:00 a.m., March) the highest hourly system load value determined by the simulations is plotted. The result is an image representing the load shape, as shown in Figure 36 for Parcel A. Figure 37 shows the annual energy (kWh) shape for this load. In this plot, each point of the surface represents the total energy consumed at this hour of day for the month. Both types of plot play an important role in understanding the loading characteristics.

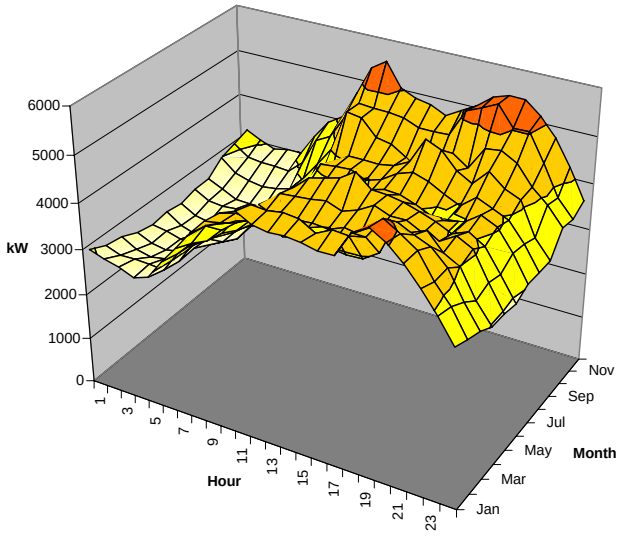

Figure 36: Parcel A Peak Load Profile (no PV)

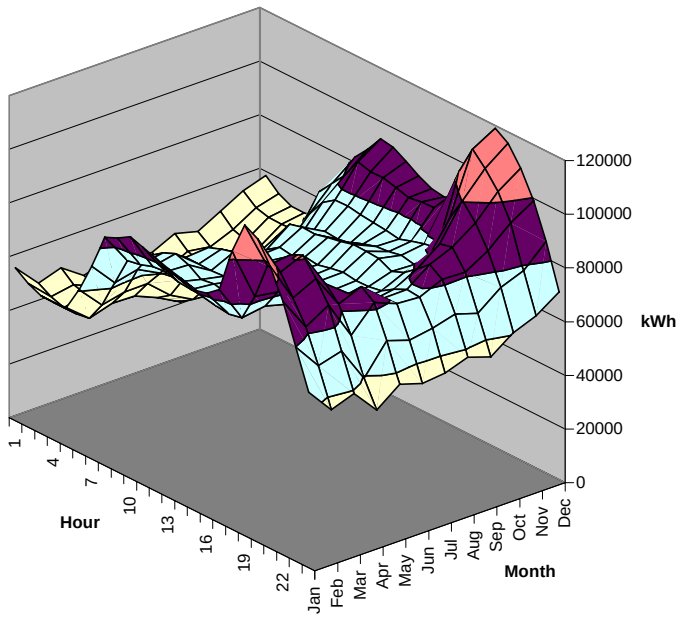

Figure 37: Annual energy load shape assumed for Parcel A

Figure 38 shows the impact that the solar PV generation has on the energy drawn from the utility system. There is a substantial chunk taken out of the mid-day energy demand characteristic. This 'chunk' is a reflection of the solar PV output shape (Figure 39).

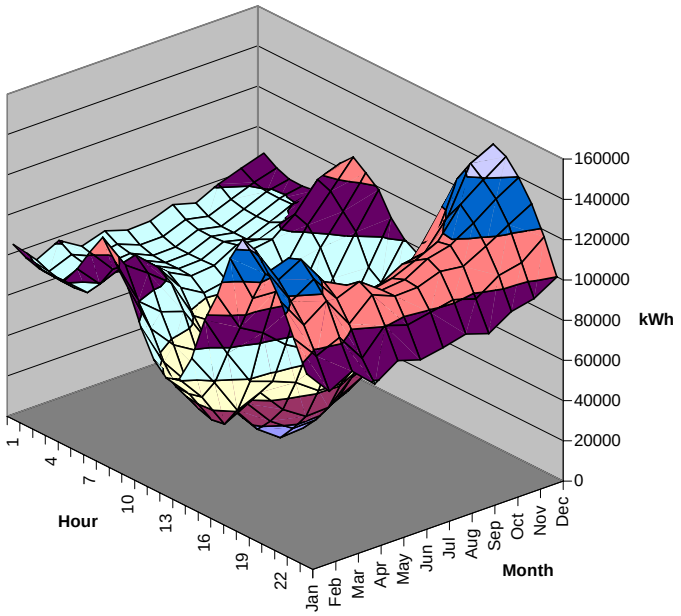

Figure 38: Net energy shape from PG&E after Parcel A build-out with 1800 kW solar PV (includes existing loads on Hunter's Point)

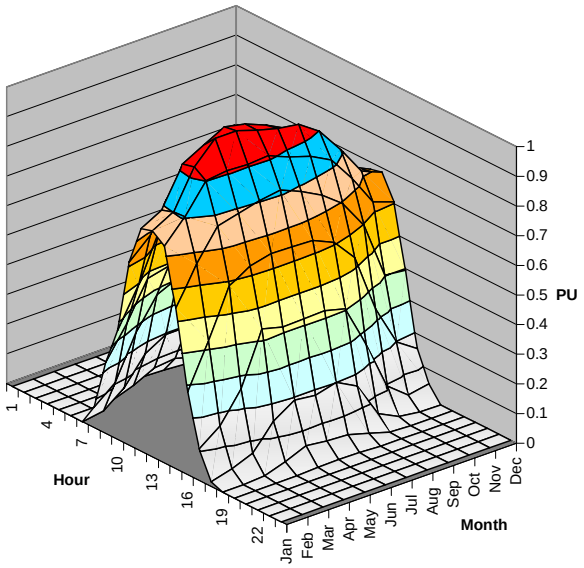

Figure 39: Assumed solar PV power output shape

The remaining figures in this section depict the energy consumption shapes assumed for Parcels B, C, and D.

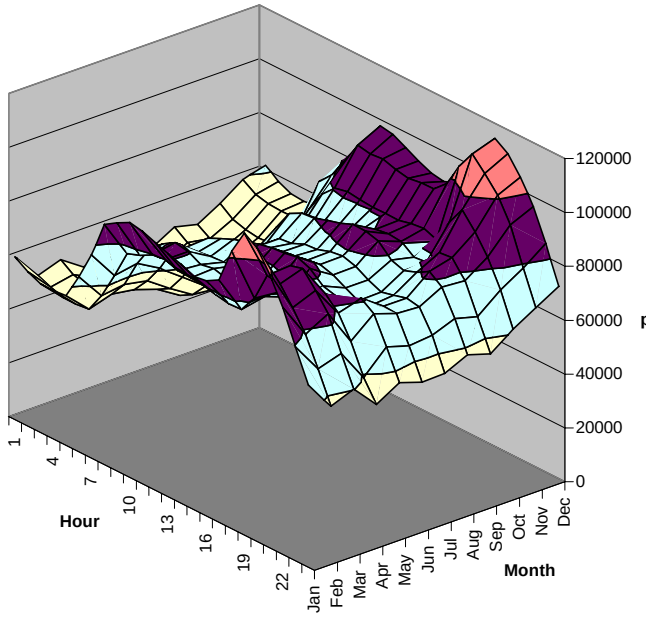

Figure 40: Annual energy (kWh) load shape assumed for Parcel B

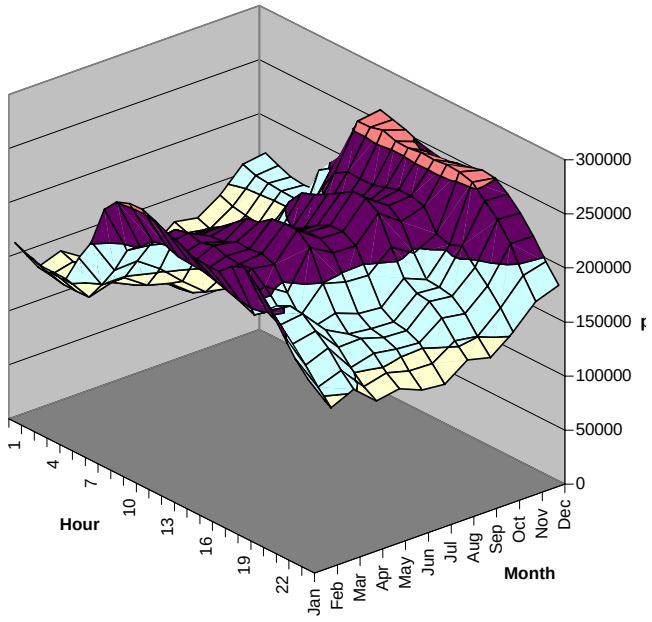

Figure 41. Annual energy (kWh) load shape assumed for Parcel C

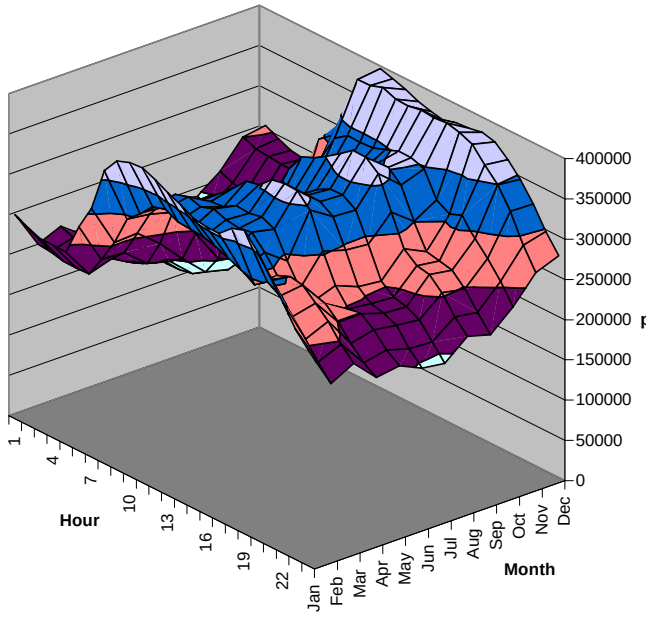

Figure 42: Annual energy (kWh) load shape assumed for Parcel D

4.2. Description of the Development Phases

The following charts and diagrams depict the loading on the system and required RDG capacities in a variety of ways for each of the phases of the development. These charts are primarily focused on the amount of supplemental RDG required to supply the HPNS load. The solar PV generation specified for the development is assumed to be embedded in the load characteristic.

A snapshot power flow one-line diagram of Phase 1a of the development is provided in Figure 43 so that the reader can better understand which part of the development is being considered. The thickness of the lines in the diagram is in proportion to the load flowing. Therefore, the thicker lines will be in the area under study.

The minimum required RDG capacities were determined by annual simulation of the system load at the end of each phase. A hypothetical infinitely-dispatchable generator was assumed to exist at the point where the 12 feeders converge. The generator was dispatched to prevent the incoming line from overloading.

4.2.1. Phase 1a: Parcel A

No supplemental DG is required to serve this phase. Figure 43 shows the relative loading for Phase 1a.

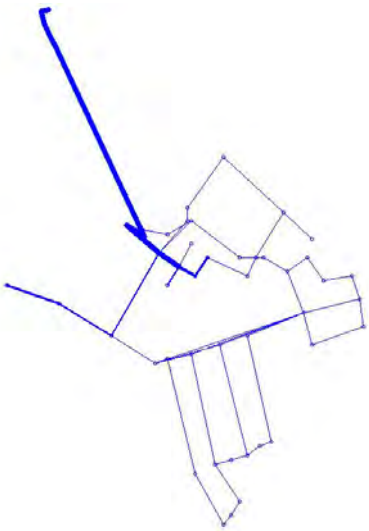

Figure 43: Illustration of relative loading for Phase 1a

Figure 44 and Figure 45 are included here to illustrate the impact that the solar PV generation has on the power being drawn from PG&E through the 12 kV line from the existing substation.

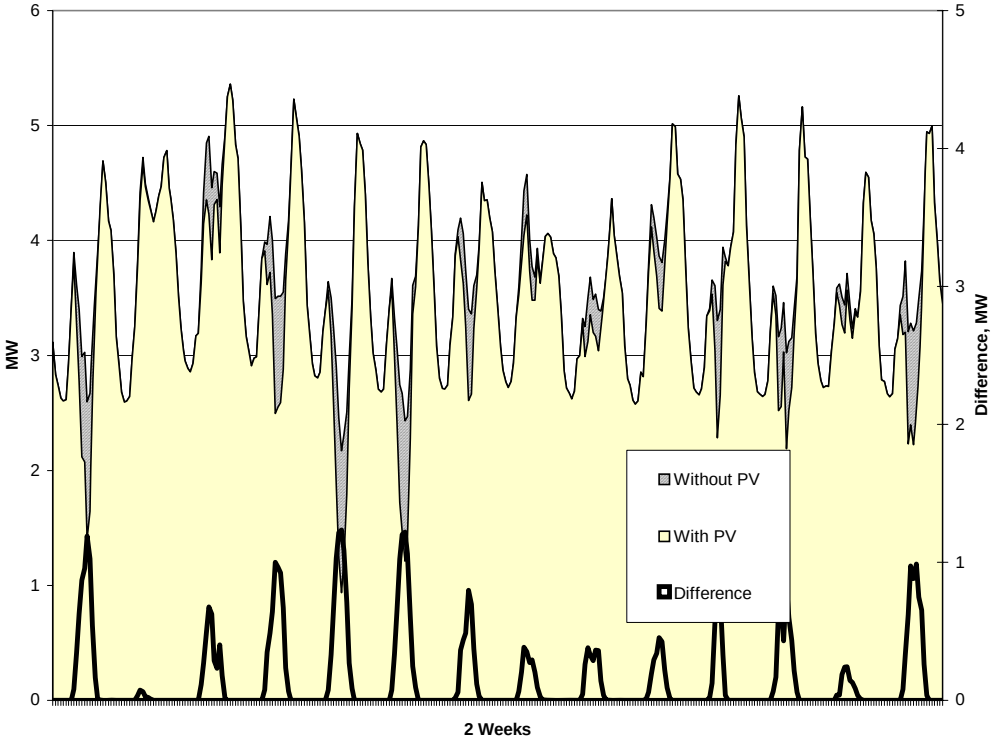

Figure 44: Impact of 1.8 MW solar PV generation on the kW demand from the incoming PG&E line during peak loading in winter

Figure 44 illustrates one of the issues with solar PV generation for serving loads in this area. There is not a good match between loading and PV output in the winter. This graphic shows the net load with PV superimposed over the simulation without PV for a two-week period. Where the cross-hatched area shows through the solid filled (yellow) curve, the PV is effective in reducing the load demand. The 'difference' curve is the output of the solar PV generation. The daily load peak is delayed in time relative to the PV output and the peak load is not reduced. In later phases of the development, supplemental RDG will be required to cover this load.

In the summer for Phase 1a, there are days where it is projected that the PV output may actually exceed load for a few hours. This is illustrated in Figure 45, where a better match between load and PV output is expected for the summer.

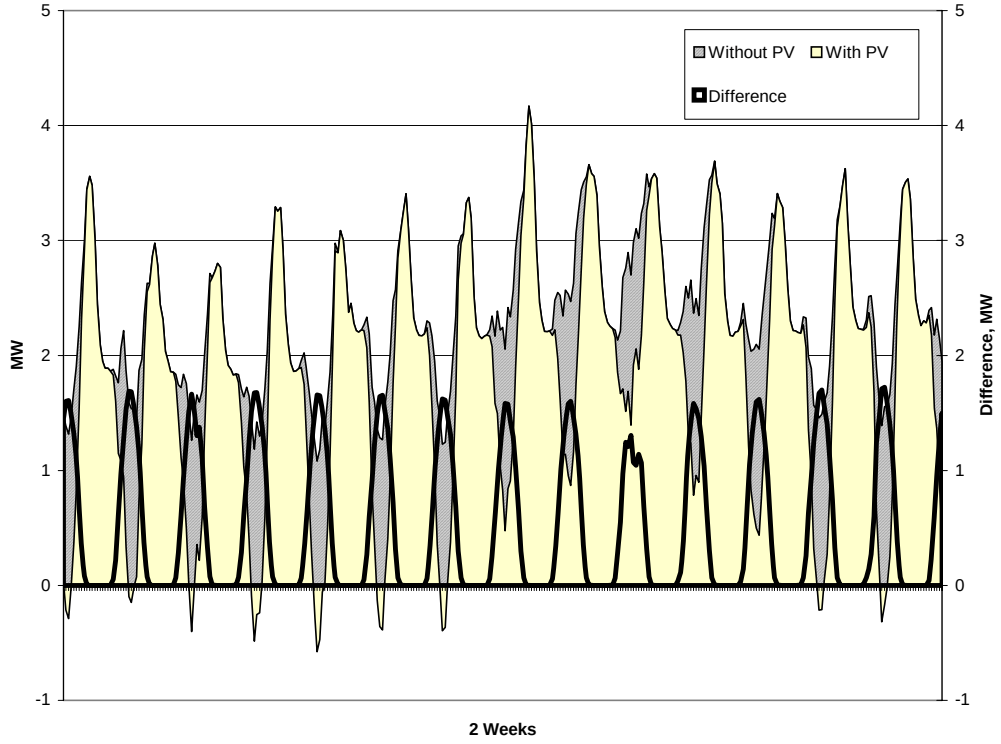

Figure 45: Impact of 1.8 MW solar PV generation on the kW demand from the incoming PG&E line during two weeks in summer

4.2.2. Phase 1b: Parcel A + Parcel B

Figure 46 shows the relative loading for Phase 1b.

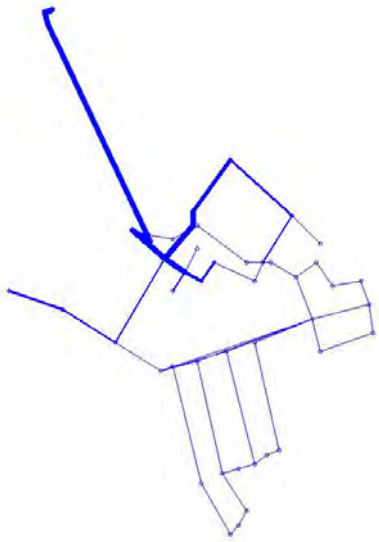

Figure 46: Illustration of relative loading for Phase 1b

At the end of Phase 1b, the load will exceed the assumed 8 MW limit of the line. Figure 47 shows the computed minimum kW and kVAR dispatch characteristics required for RDG to meet the load.

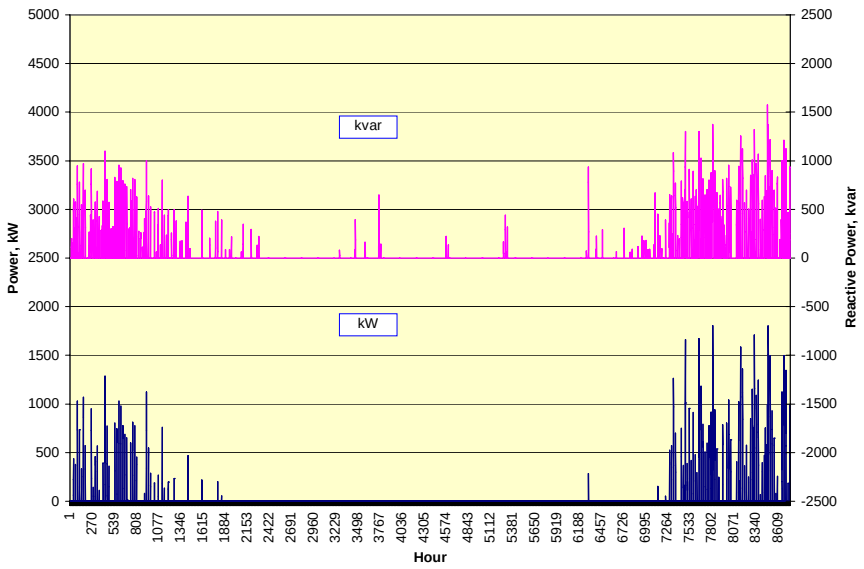

Figure 47: Supplemental RDG kW and kVAR output required for Phase 1b to maintain incoming PG&E line below 8 MW

The supplemental RDG is required mostly in the winter months for a few hours on some days. Figure 48 is a blow-up of a two-week time period around the winter peak and illustrates the extent of RDG output required. The solar output is so weak that there are few days where there is a significant difference in the required supplemental dispatch with or without PV.

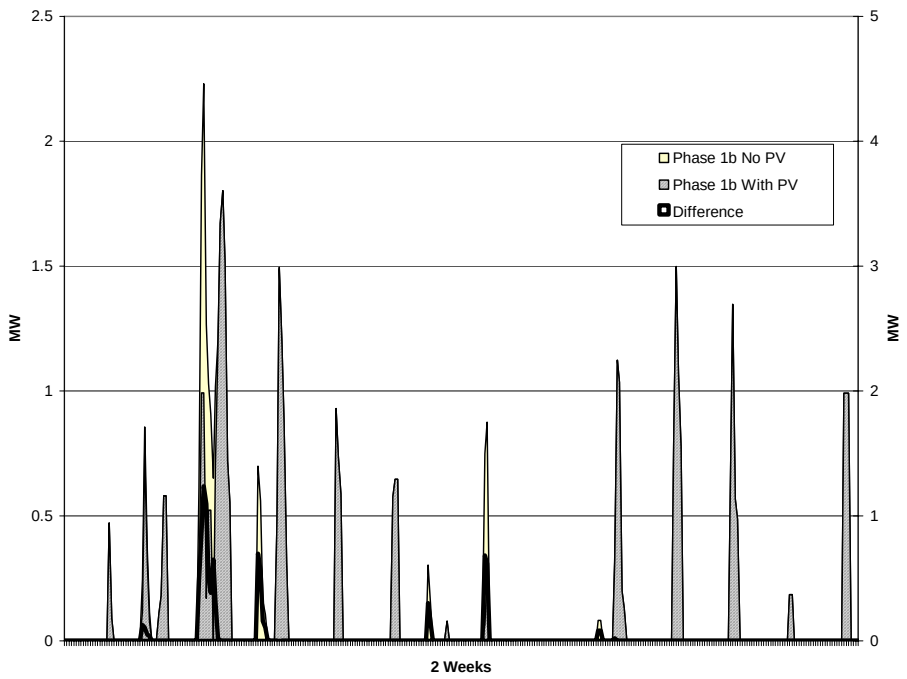

Figure 48: Comparison of RDG requirement with and without the solar PV for two weeks during winter peak illustrating the expected coincidence of load and generation for Phase 1b

In this case, the areas where the solid fill (yellow) shows through the cross-hatched fill are the times where the PV is effective.

The peak generation required is less than 2 MW. The generation would have to operate an average of six hours on peak demand days; less on other days.

Figure 49 shows the annual profile or peak power output required by the dispatchable generation. Figure 50 shows the energy associated with that dispatch. The vast majority of the energy would be required in the three or four winter months in the early afternoon.

This characteristic strongly suggests meeting the excess demand with peaking generation – possibly peaking generation leased only for the winter months.

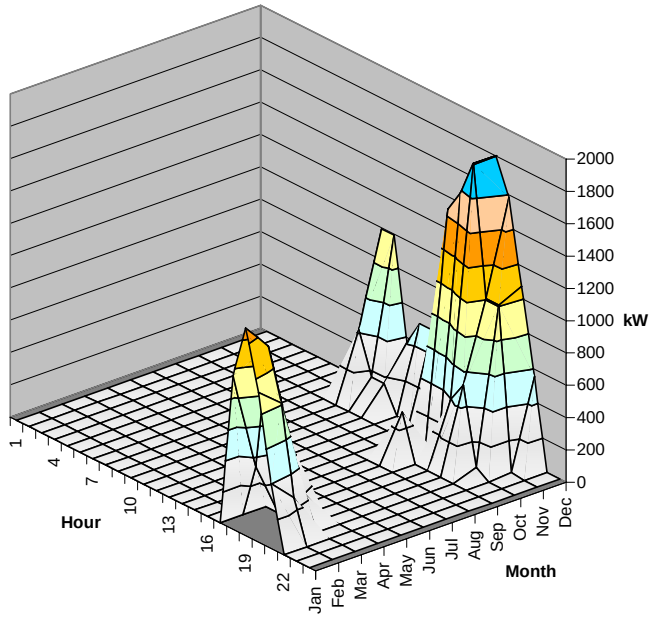

Figure 49: Annual shape of Supplemental RDG hourly peak power output required to keep the loading on the incoming line less than 8 MW for Phase 1b

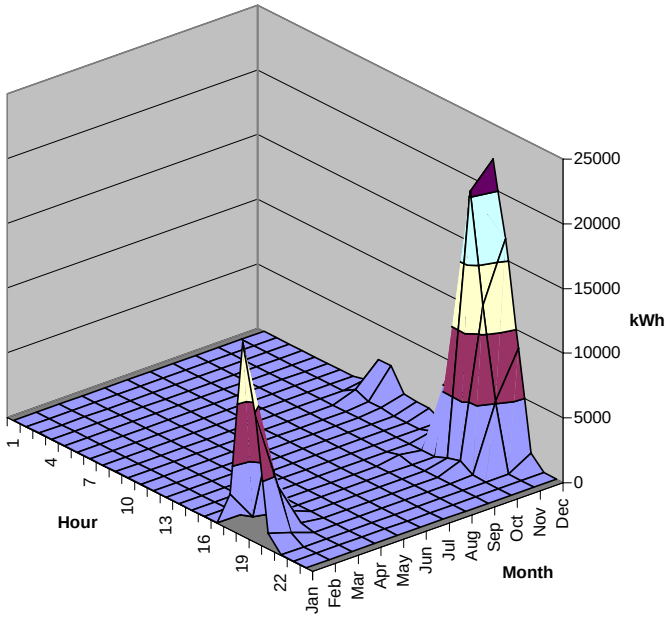

Figure 50: Annual shape of Supplemental RDG hourly energy (kWh) output required to keep the loading on the incoming line less than 8 MW for Phase 1b

4.2.3. Phase 2: Parcels A, B, and C.

Figure 51 shows relative loading for Phase 2.

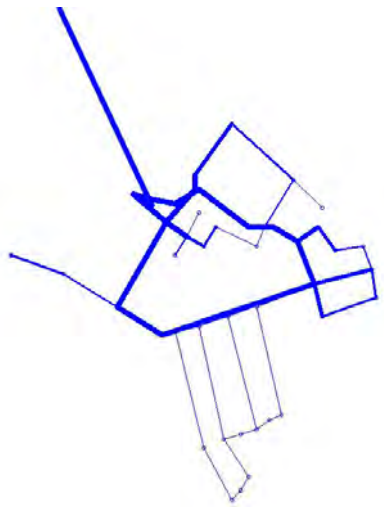

Figure 51: Illustration of relative loading for Phase 2.

For Phase 2, two basic cases were considered: 1) 8 MW limit on the PG&E service; 2) 12 MW limit on the PG&E service. The annual profiles shown in Figure 52 and Figure 53 indicate that the supplemental RDG is needed most of the time in values ranging from 5 MW to 13 MW. This suggests some amount of base loaded RDG should be installed, perhaps in two steps: one for summer and an additional amount for the winter. Figure 54 shows the energy associated with that dispatch.

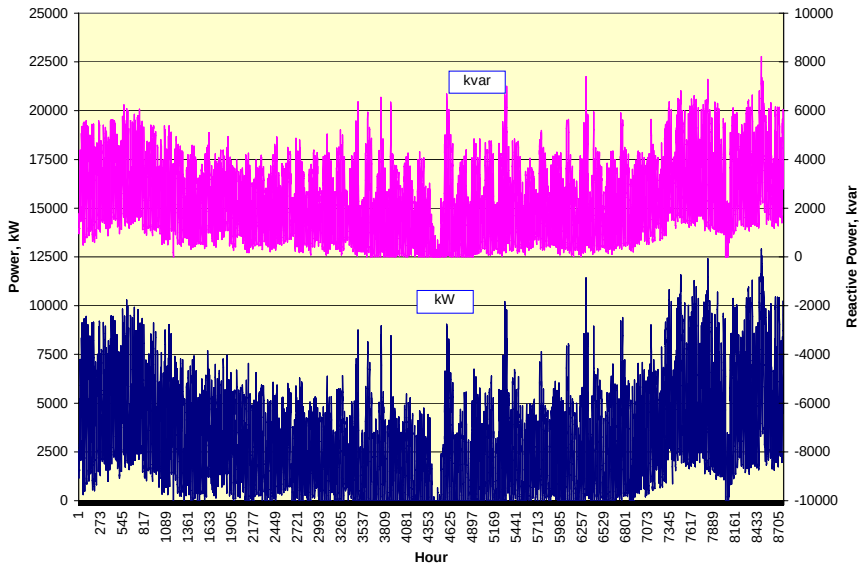

Figure 52: Supplemental RDG kW and kVAR output required for Phase 2 to maintain incoming PG&E line below 8 MW

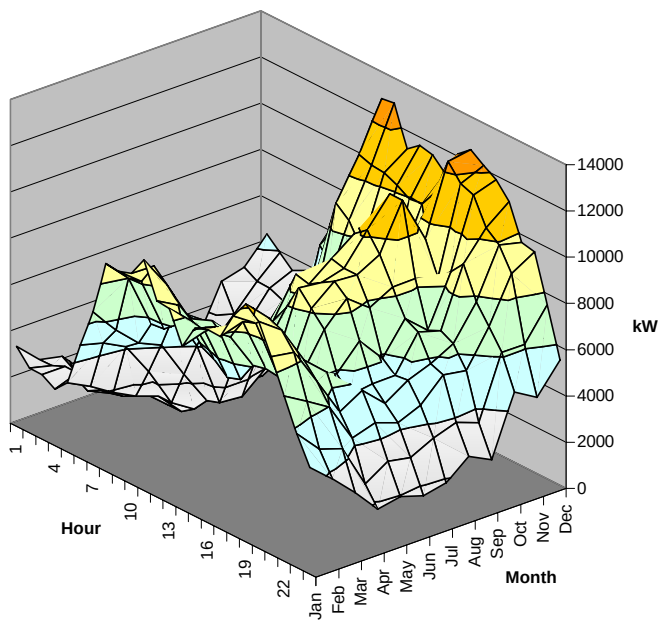

Figure 53: Annual shape of supplemental RDG hourly peak power output required to keep the loading on the incoming line less than 8 MW for Phase 2

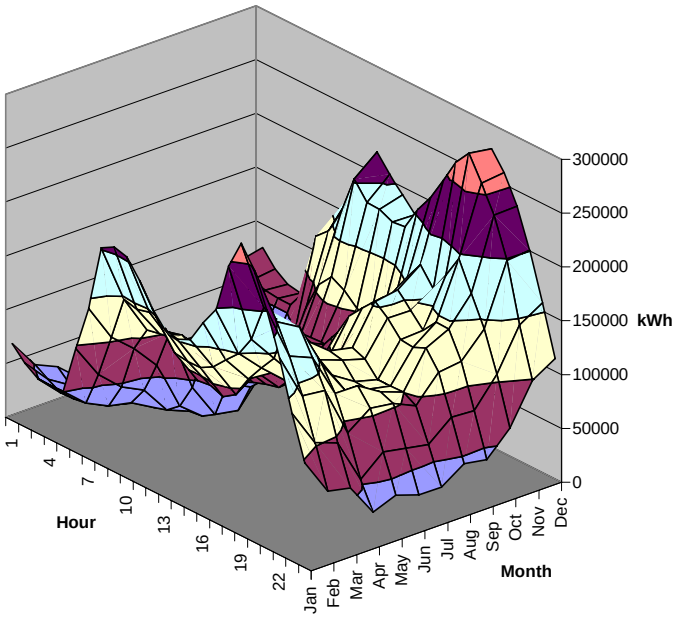

Figure 54: Annual shape of Supplemental RDG hourly energy (kWh) output required to keep the loading on the incoming line less than 8 MW for Phase 2

Figure 55 shows the supplemental RDG required under the 12 MW limit case.

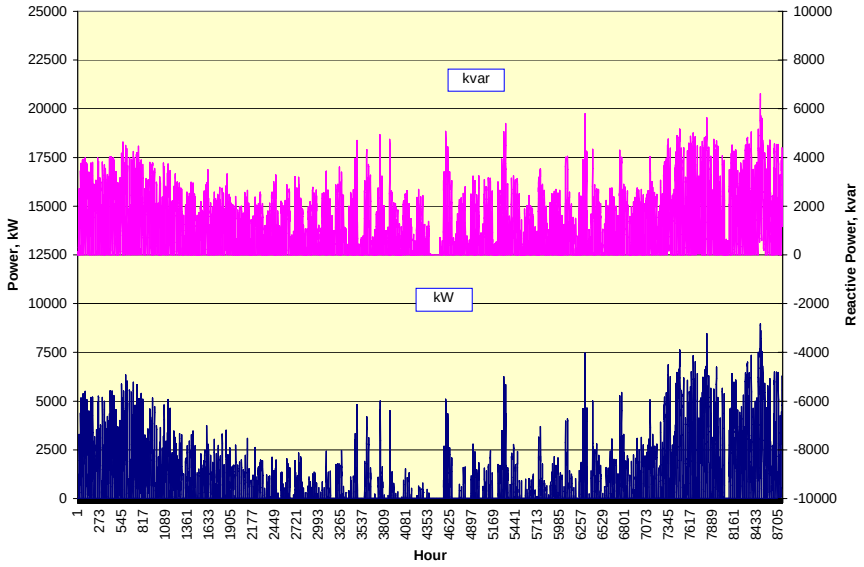

Figure 55: Supplemental RDG kW and kvar output require for Phase 2 assuming incoming PG&E line can be upgraded to supply 12 MW

4.2.4. Phase 3: Parcels A, B, C and D.

Figure 56 shows relative loading for Phase 3.

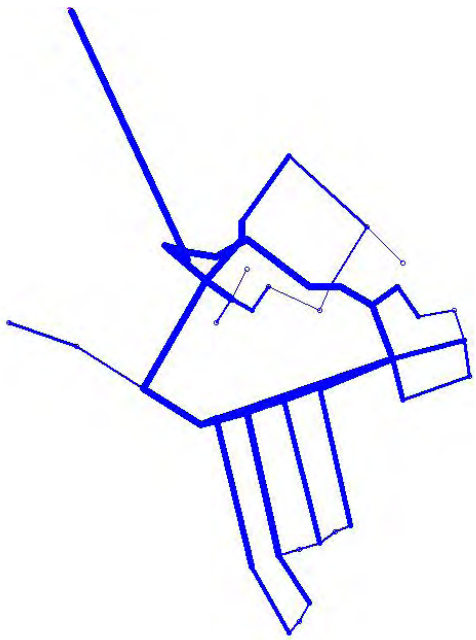

Figure 56: Illustration of relative loading for Phase 3

As with Phase 2, two limits on the amount of power required from PG&E were investigated: 8 MW and 12 MW.

Figure 57 suggests a base RDG capacity of approximately 20 MW is needed, supplemented by somewhat more than 10 MW to meet winter demand and sporadic peaks during the other months.

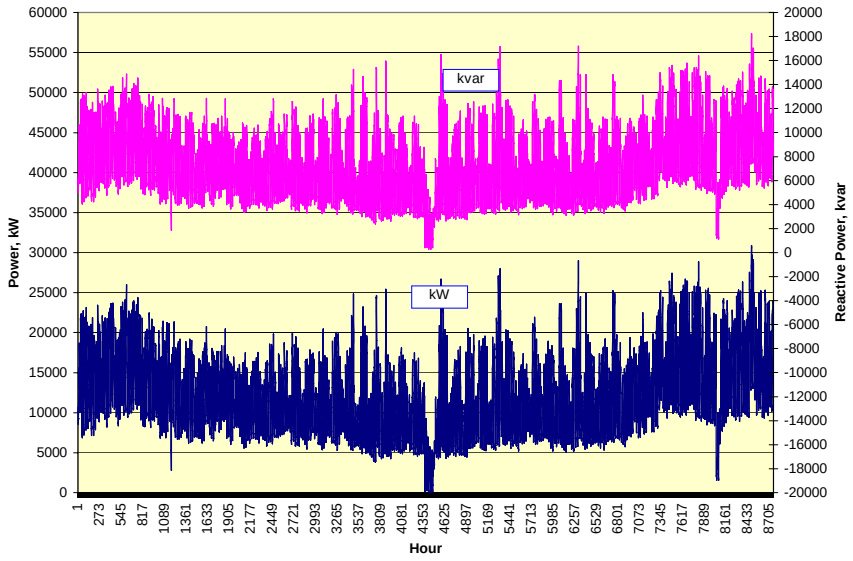

Figure 57: Supplemental RDG kW and kVAR output required for Phase 3 to maintain incoming PG&E line below 8 MW

Figure 58 shows the peak power output required by the dispatchable generation in Phase 3, and Figure 59 shows the energy associated with that dispatch.

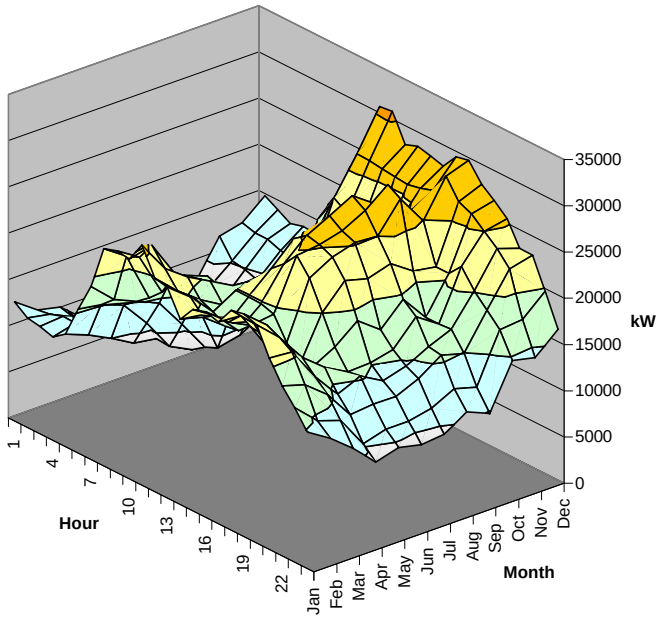

Figure 58: Annual shape of supplemental RDG hourly peak power output required to keep the loading on the incoming line less than 8 MW for Phase 3

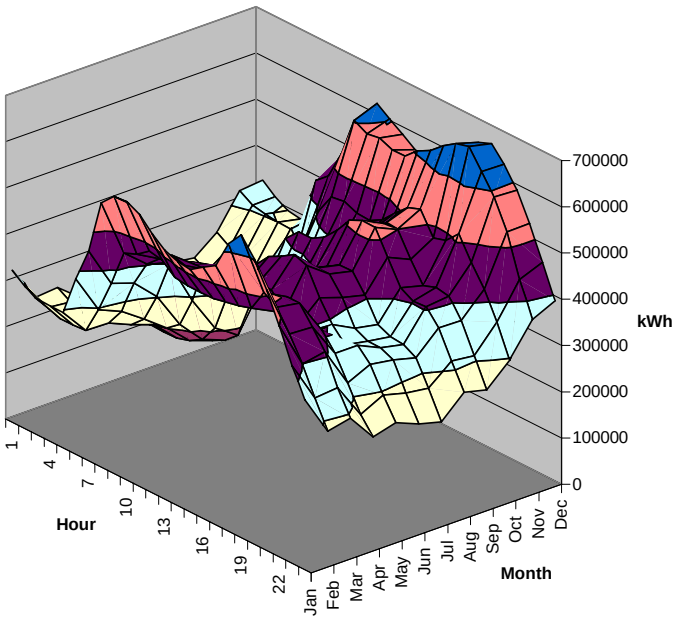

Figure 59: Annual shape of supplemental RDG hourly energy (kWh) output required to keep the loading on the incoming line less than 8 MW for Phase 3

Figure 60 shows the supplemental RDG required under the 12 MW limit case.

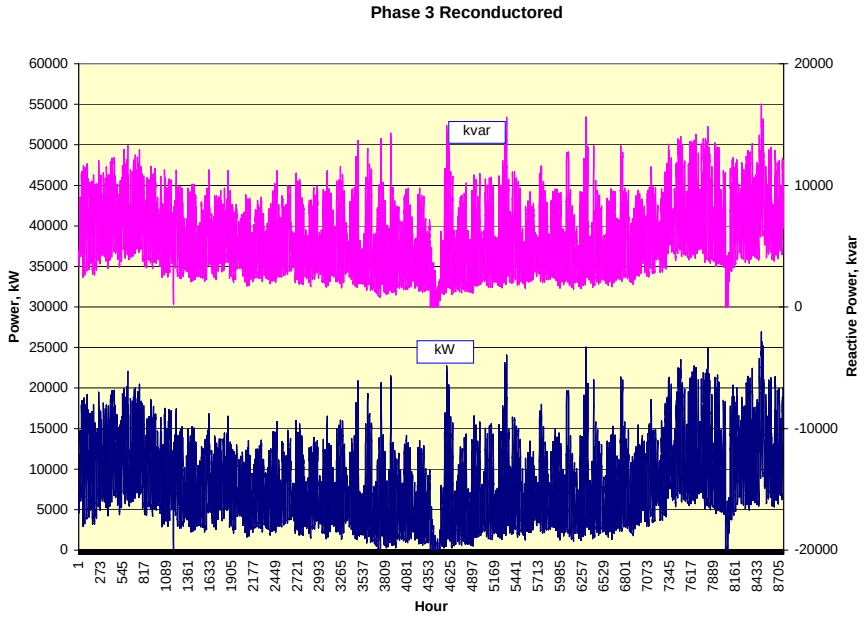

Figure 60: Supplemental RDG kW and kvar output require for Phase 3 assuming incoming PG&E line can be upgraded to supply 12 MW

4.3. Summaries of Demands and Savings

Table 22 and Table 23 summarize several of the key load-related results for the various cases considered.

Table 22: Energy and Demand Savings on PG&E Line

Phase	Line Rating	Supplemental RDG	PV	Purchased Power Savings		Peak Demand Savings	
	MW	kW	kW	MWh	% of gen	kW	% of RDG
1a	8	0	1800	3162	100.2797	----	----
1b	8	1805	3100	5602	100.0004	1756	97.29023
2	8	12918	3304	34547	100.0188	12874	99.65378
3	8	30856	3304	115865	100.0082	30822	99.89235
2	12	8965	3304	12606	100.0049	8921	99.50691
3	12	26912	3304	81422	100.0091	26880	99.88321

Table 22 shows the reduction, or savings, in energy and power demand achieved by producing much of the power by RDG at the HPNS. The purchased power savings almost directly coincide with the MWh produced by the generation. There is a very slight bonus due to a slight loss reduction, but nothing like the 4% or more commonly achieved when RDG is placed on longer, more heavily loaded distribution system. The distances are too short for the RDG to have much additional impact. Also, this reflects the simulated control strategy of dispatching the supplemental RDG so that the maximum incoming line loading stays approximately the same. The reduction in peak demand is also virtually identical to the amount of RDG applied. The slight deviations from 100% are likely due more to the deadband controller algorithm used in the simulation than anything else. The peak demand computed might fluctuate ±50 kW.

Annual feeder line losses range from 0.74% to 1.2%. This is a low figure that is again reflective of the relatively short distances and the dilution of the load currents in the shipyard with numerous branch feeders.

Table 23: Load Supplied by RDG

Phase	Line Rating	Load	Installed	PV Energy	% of Load	Supplemental	% of Load
	MW	MWh	PV kW	MWH	From PV	RDG MWH	From RDG
1a	8	25630	1800	3154	12.3	0	12.3
1b	8	48913	3100	5431	11.1	171	11.5
2	8	102885	3304	5789	5.6	28752	33.6
3	8	183685	3304	5789	3.2	110067	63.1
2	12	102885	3304	5789	5.6	6816	12.3
3	12	183684	3304	5789	3.2	75626	44.3

Table 23 indicates the minimum percentage of the load that would be supplied by RDG for the various phases of development and assumed incoming line ratings. For Phase 1b (Parcels A and B), the rooftop PV that is specified would serve 11.1% of the total load and the supplemental peaking generation, or storage, would serve an additional 0.4% ofthe load. As the development progresses to Phases 2 and 3, the percentage of the load served by RDG increases dramatically to 33% and 63%, respectively. If it is assumed the amount of power that can be received from PG&E increases to 12 MW from 8 MW, a smaller amount of supplemental RDG is required. In that case, the minimum percentage of the load that would have to be served from RDG drops to 12% and 44% for Phases 2 and 3, respectively. Of course, RDG could serve a much higher percentage of the load if the resource is available. These numbers represent the minimum RDG that is required in order to maintain service to the loads.

4.4. Load and Resource Engineering Summary

The development can proceed through Phase 1 (Parcels A and B) with a relatively minor amount of peaking generation to cover potential overloads. Approximately 2 MW of dispatchable RDG would be required. It would be expected to operate the equivalent of 100 hrs per year, with the maximum run time each day averaging approximately six hrs.

To meet Phase 2 and Phase 3 load, a significant amount of base load RDG would have to be employed. Since the demand is higher in the winter, it would be conceivable to do this with two or more steps of base load RDG. The smaller step would be operated in the summer.

The RDG in Phases 2 and 3 would be operating a large percentage of the time. It would also require a relatively sophisticated control system to coordinate the dispatch with the limits on the power that can be drawn from PG&E.

4.5. Meeting the Demand at HPNS

As described in the Distribution Avoided Cost section, the development plans for HPNS involve three distinct phases, covering four parcels of land. Table 24 shows the three planned phases of development and the associated increased load. Figure 61 is a map of the HPNS parcel boundaries.

Table 24: HPNS Planned Development Phases and Associated Load Growth

Development Phase	HPNS Land Parcel	Peak MW (from Phase)	Peak MW (cumulative)
Phase 1a	A	4.5	4.5
Phase 1b	B	4.6	9.1
Phase 2	C	11.5	20.7
Phase 3	D	17.8	38.4

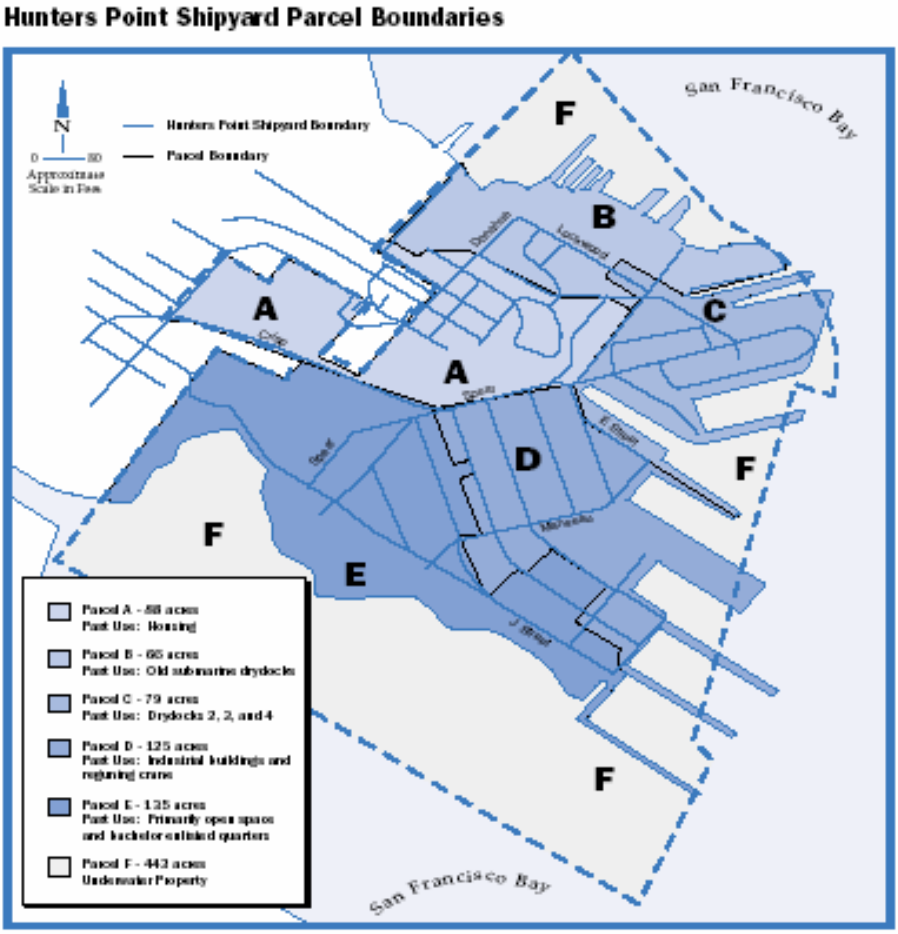

Figure 61: HPNS Area Map and Land Parcel Boundaries

We evaluated the load levels in Table 24 as our base case. However, the SFPUC is planning to add numerous energy efficiency measures as part of the construction process which would significantly reduce the peak load demand at the HPNS. A 45% reduction of *peak* load requirements would result from planned efficiency additions. Table 25 shows the resulting reduction in peak load MW required. The cumulative peak MW in the last column is shown here for illustrative purposes and is not an engineering estimate of the impact.

Table 25: Energy Efficiency Impact on HPNS Load Growth by Development Phase

Development Phase	HPNS Land Parcel	Peak MW (from Phase)	Peak MW (cumulative)
Phase 1a	A	4.5	4.5
Phase 1b	B	0.5	5.0
Phase 2	C	6.4	11.4
Phase 3	D	9.8	21.1

Using these estimates of load growth at HPNS, we mapped out the potential 'Paths' or series of choices that may occur throughout the HPNS redevelopment phases. Figure 62 shows the map with nine paths that corresponds with the base-case growth with the peak load levels in Table 24. Figure 63 shows a similar map, with only five paths, for the investments associated with the peak loads after incorporating energy efficiency measures in Table 25.

Each path represents a series of choices for investments to adequately serve the additional load at each phase of development. There are two predominant traditional engineering or "wires" solutions to meet the HPNS increased demand:

1. Reconductor a portion of the existing 12kV line serving the HPNS
2. Upgrade the existing line to a 115kV line

The first option provides an additional 4 MW of added capacity but not enough to complete the entire development without further system modifications and is a relatively inexpensive investment on a per MW basis. The 115kV line upgrade would obviate any need for other investments in wires or RDG as it would provide greater capacity than is expected to be needed at the HPNS site. Of course, this investment is substantially larger than the reconductoring.

The estimated engineering cost of the reconductoring option is $100,000, whereas the estimated engineering cost of the line upgrade is $1.25 million.[16] We assume, for this

[16] In calculating the avoided costs, the engineering costs are increased by 30% to represent fully-loaded project costs.

analysis, that the line upgrade costs are borne by PG&E and therefore avoided costs for this investment are calculated using PG&E's cost of capital (7.57%). Additionally, an inflation rate of 2% on the cost of the upgrades is assumed for this analysis.

The timing of the investment for each option affects the resulting avoided costs. Given that the development of the HPNS is planned to occur in three distinct phases, the timing options for meeting the load requirements of each phase can vary considerably. Table 26 summarizes the assumptions used for the engineering or 'wires' solutions at the HPNS.

Table 26: Baseline Avoided Cost Assumptions for Wires Solutions

Phase 1b Start Year	2007
Phase 2 Start Year	2010
Phase 3 Start Year	2012
Reconductoring cost (000s, 2005$)	$ 100
115 kV upgrade cost (000s, 2005$)	$ 1,250

In order to determine the most cost-effective path to adequately serve the new load at the HPNS, we use the results of the RDG Economic Screening Analysis as a comparison with the traditional wires solution.

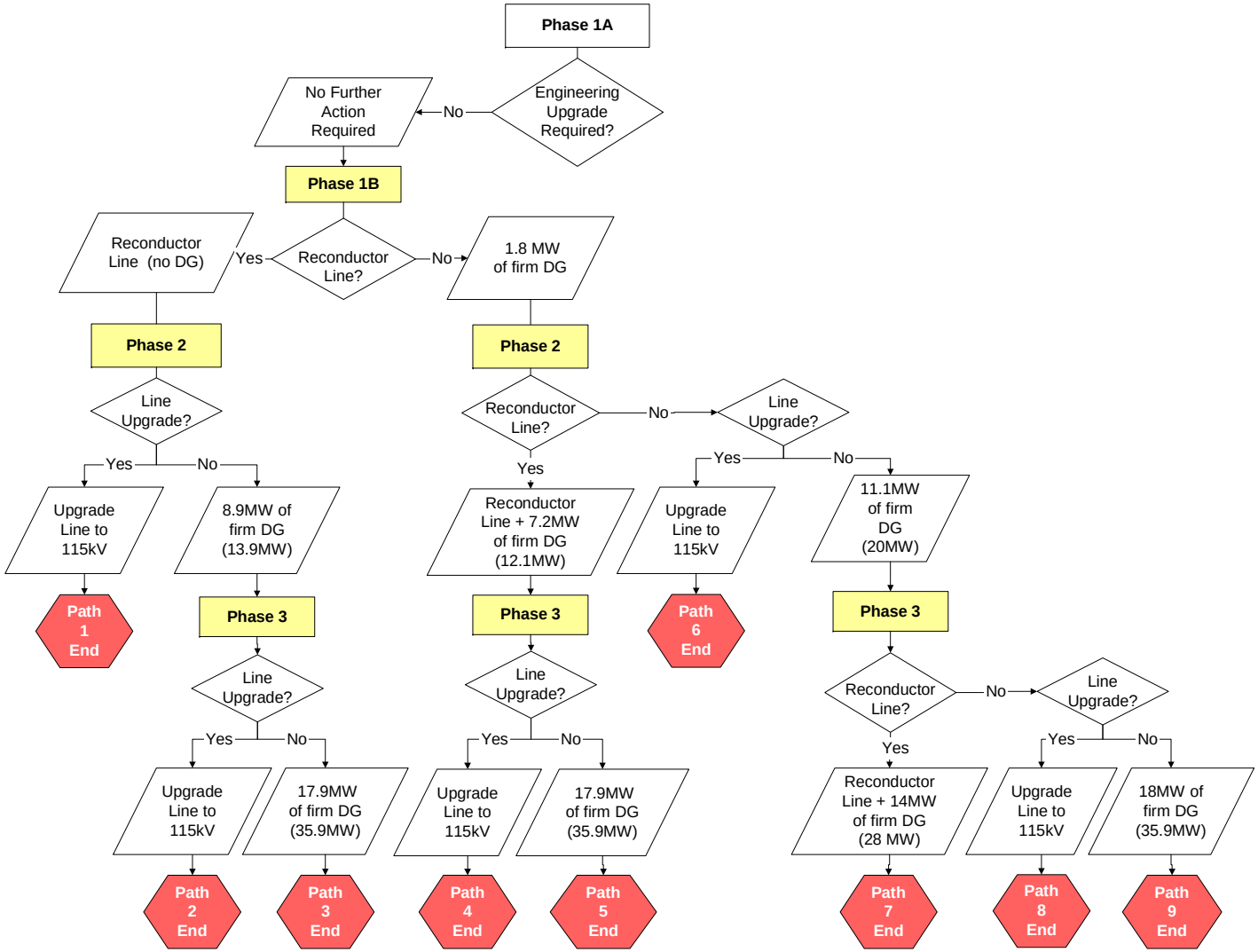

Figure 62: Paths for Investment Options at HPNS (no Energy Efficiency)

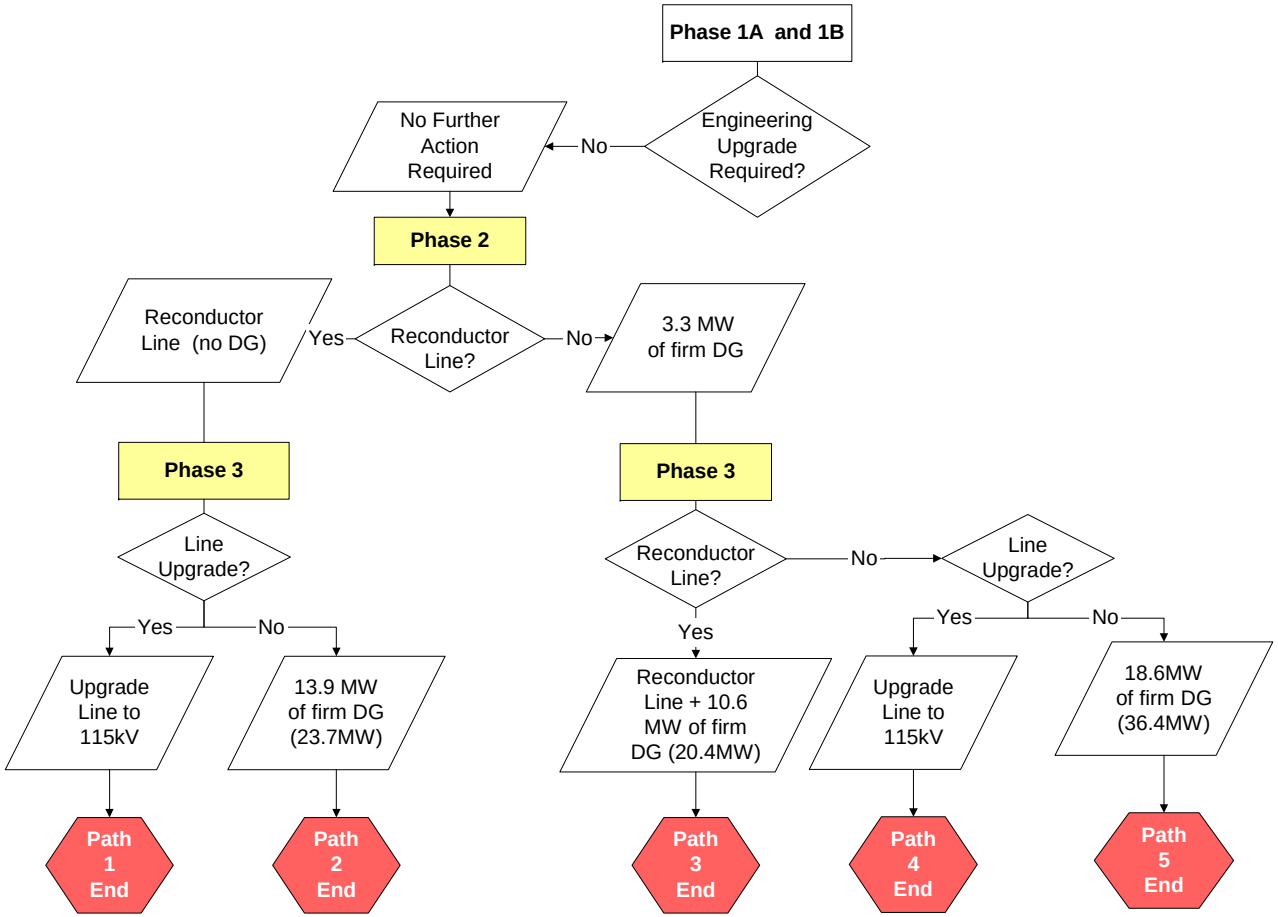

Figure 63: Paths for Investment Options at HPNS with Energy Efficiency Measures

4.6. Comparing Alternative Solutions

In order to determine what the most cost-effective solution, or combination of solutions, to meeting the HPNS load requirements we evaluated the following two cases from the TRC perspective with and without energy efficiency in the development plan.

1. Comparing traditional wires solutions to a single RDG technology
    a. The RDG technology used is the 800kW biogas-reciprocating engine with CHP. The CHP was selected because it is the most cost-effective RDG solution available in our screening. To achieve capacities greater than 800kW, we assume multiple units are installed.
    b. In some paths the reconductoring wires solution is employed along with the RDG technology to meet the load.
2. Comparing traditional wires solutions to a combination of baseload and peaking DG technologies
    a. The baseload RDG technology used is the 800kW biogas-reciprocating engine with CHP and the peaking RDG technology is the 100kW Polysulfide Bromide flow battery (Regensys technology).
    b. In some paths the reconductoring wires solution is employed along with the RDG technologies to meet the load.

Additionally, we repeated the above analyses from the UCT perspective. Some of the paths that incorporate RDG may prove cost-effective from the TRC perspective but not from the UCT perspective.

4.6.1. Comparing traditional wires solutions to a single RDG technology

Figure 64 and Figure 65 are the same maps shown in Figure 62 and Figure 63 respectively but the net benefits of the combined wires and RDG solution associated with each decision and path are added in grey boxes. In Figure 64, Path 9, a Phase 1B net cost of $66,000 to reconductor the line may be compared to a net benefit of $2,662,000 to add 1.8MW of RDG. There is a net benefit for the RDG solution because we are using a cost-effective technology to begin with and the benefits grow with the amount of RDG installed. Moving to Phase 2, along Path 6, the line is not reconductored, resulting in a net cost of $778,000 to upgrade the line. This may be compared to a net benefit of $25,375,000 to add 11.1MW of firm RDG along Paths 7, 8, and 9, and to the net benefit of $21,734,000 associated with reconductoring the line and 7.2 MW of firm RDG along Paths 4 and 5. The cumulative values for each of the Phase totals are shown in bold below each path end.

After incorporating energy efficiency, our analysis shows similar results. Figure 65 shows that Path 5, which adopts the largest CHP capacity possible, has the overall greatest value of $74,782,000.

The net benefits from the TRC perspective get larger with each MW added of cost-effective RDG. So the primary limitations of a cost-effective RDG solution would include:

1. A sufficient fuel source for a large amount of generation
2. An effective use of the waste heat from a large CHP unit that would be required in the later phases of the HPNS redevelopment
3. Finding an appropriate location for the technology
4. Engineering limitations of the distribution system to handle additional RDG.

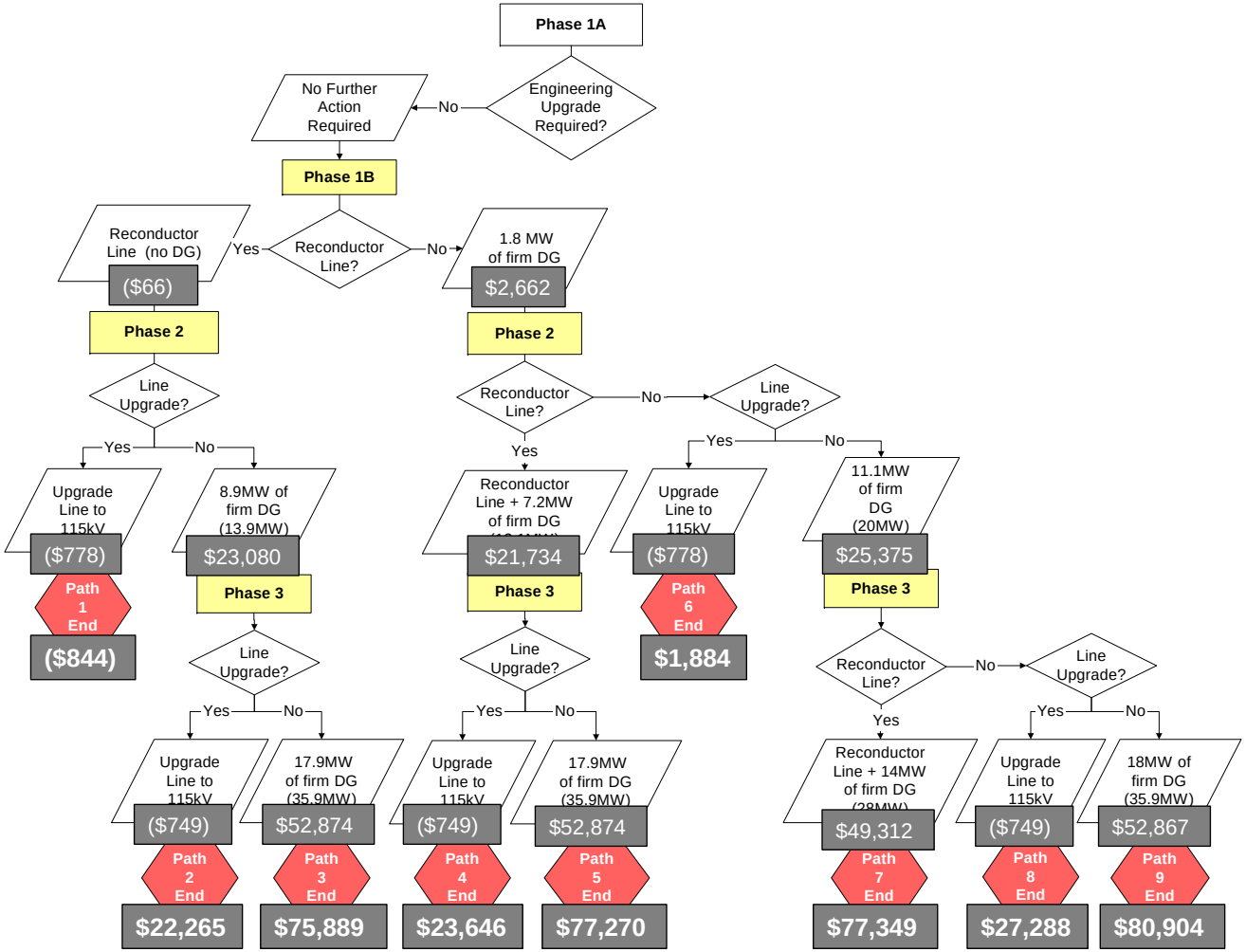

Figure 64: Costs (in 000s) for 9 Investment Paths at the HPNS (no energy efficiency). RDG technology is a baseload 800kW biogas-reciprocating engine operating with CHP

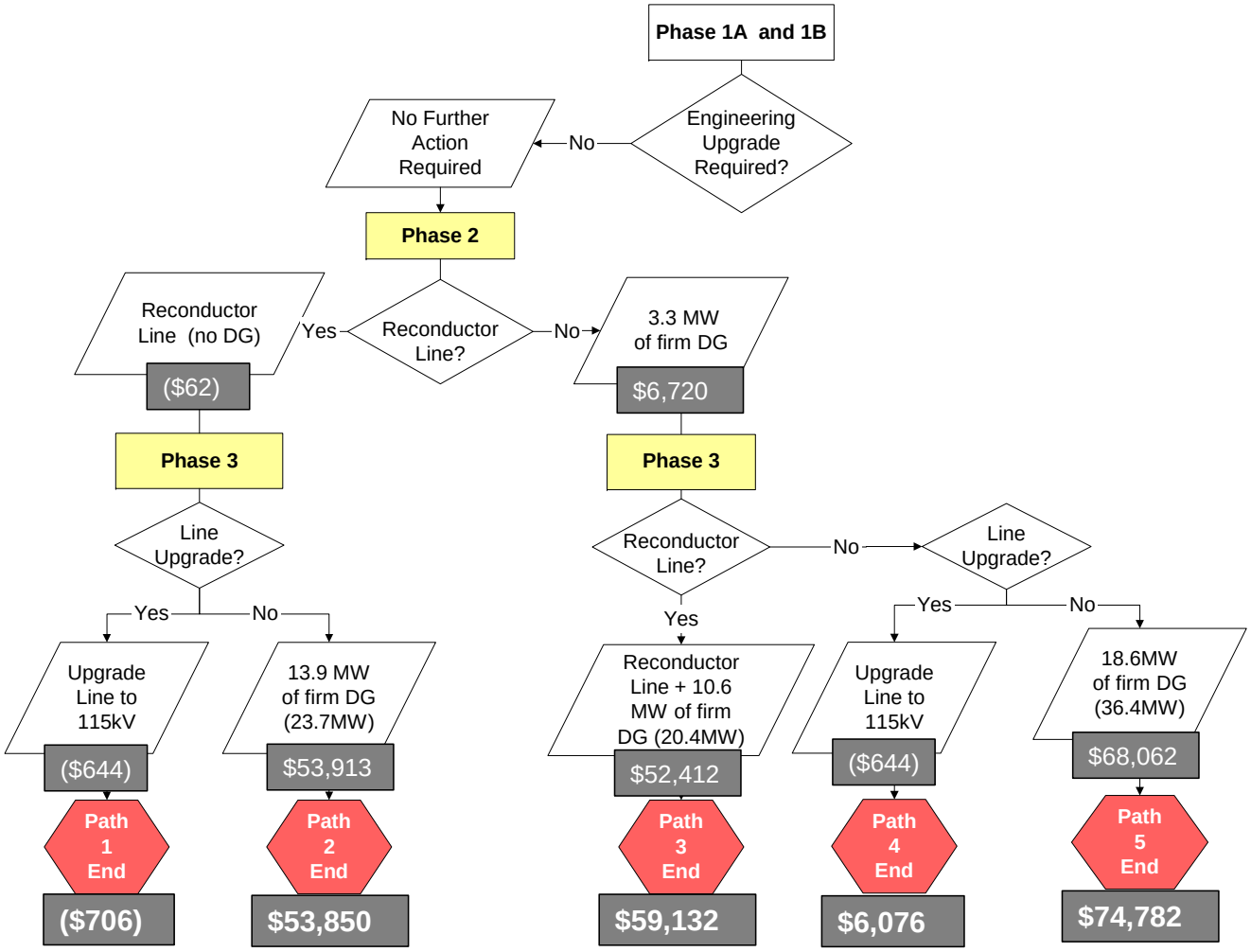

Figure 65: Costs (in 000s) for 5 Investment Paths at the HPNS (with energy efficiency). RDG technology is a baseload 800kW biogas-reciprocating engine operating with CHP

4.6.2. Comparing traditional wires solutions to a combination of baseload and peaking DG technologies

We also evaluated a combined baseload and peaking RDG solution against the traditional wires solution. In this case, we calculated the RDG results using a baseload 800kW biogas reciprocating engine with CHP along with a peaking 100kW flow battery technology as our RDG solution. We found a similar result with this combined RDG solution to the single technology comparison evaluation described above. The net benefits of the baseload RDG technology were large enough to offset the net costs of the peaking technology but as a result the total net benefits were reduced.

Figure 66 and Figure 67 show the results of the combined RDG comparison analysis for the load case without efficiency measures and with efficiency measures, respectively. Again Path 9 in Figure 66 and Path 5 in Figure 67 have the highest value because the greatest amount of cost-effective RDG is installed on these paths.

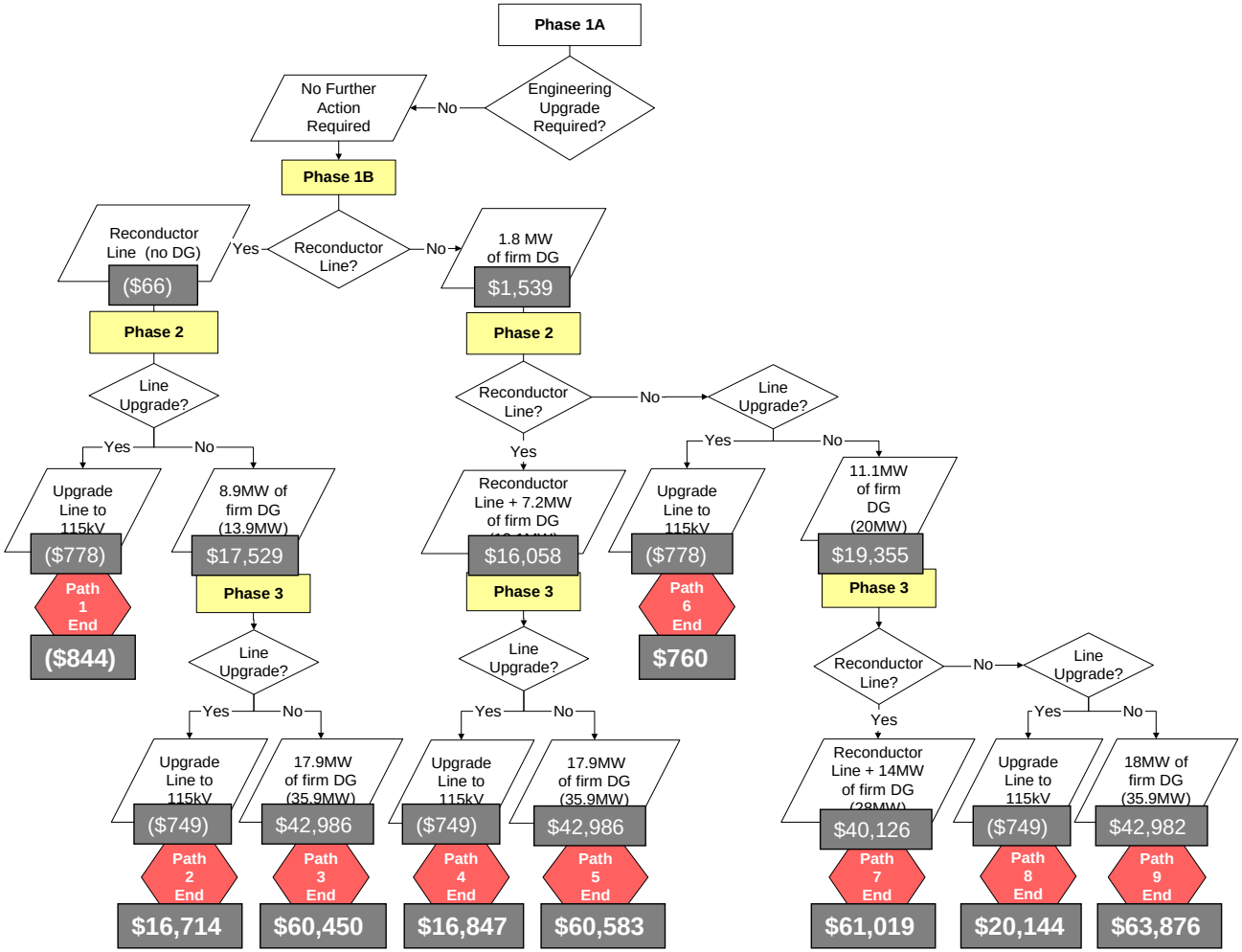

Figure 66: Costs (in 000s) for 9 Investment Paths at the HPNS (no energy efficiency). RDG solution includes a baseload 800kW biogas-reciprocating engine operating with CHP and a peaking 100kW Polysulfide flow battery

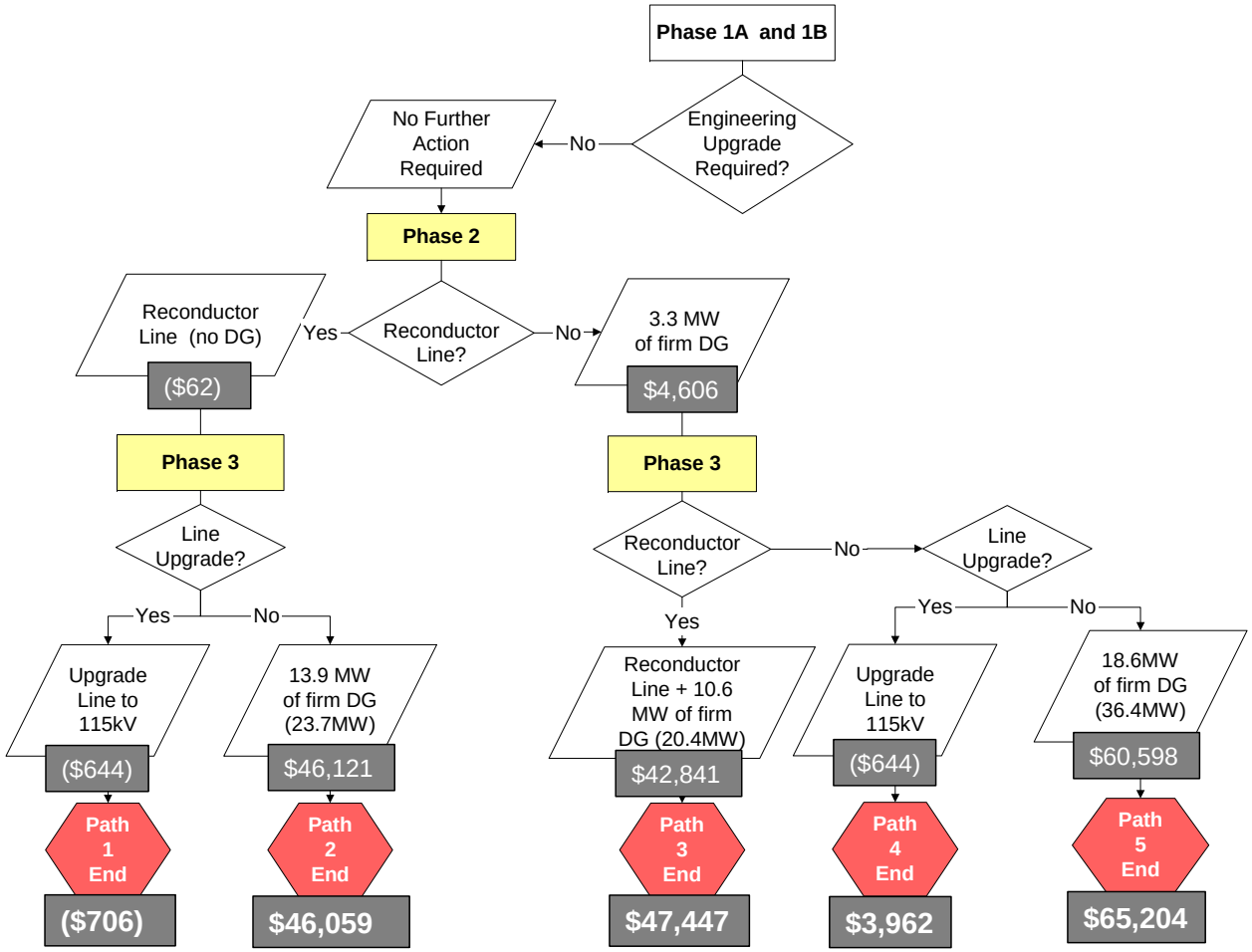

Figure 67: Costs (in 000s) for 5 Investment Paths at the HPNS (with energy efficiency). RDG solution includes a baseload 800kW biogas-reciprocating engine operating with CHP and a peaking 100kW Polysulfide flow battery

4.6.3. Comparing traditional wires solutions to an RDG solution from the UCT perspective

The analysis of biogas generation with an internal combustion engine and waste heat recovery shows positive economics from the TRC, or community cost perspective. This implies that the overall energy bill for the community is less. Located at a customer site, this type of application would also be cost-effective from the DG owner perspective because the cost of producing energy is less than the retail rate.

We further evaluate the biogas generation with CHP as a SFPUC / Hetch Hetchy installation. With this approach, the generation would be located at HPNS and directly connect to the PG&E distribution grid. The energy could then be used by SFPUC for its customers, and support the distribution system at HPNS. As we saw in the cost-effectiveness chapter, this application is nearly cost effective with a B/C ratio of 0.89. The shortfall is $0.008/kWh, or less than 1 cent per kWh. The key driver for this result, despite attractive municipal utility financing, is our expected cost of the fuel from biogas, which is estimated at $9.50/MMBtu in 2005 and escalated at 2% thereafter. To the extent that the installation fits within the SFPUC / Hetch Hetchy stated public goals of pursuing renewable energy within San Francisco, this narrow shortfall may be justified by the indirect benefits of the project.

Figure 68, below, shows the cost-effectiveness results from the SFPUC perspective with a CHP application. Assuming that SFPUC would have to pay for the line-upgrade to serve HPNS, the least cost alternative would cost $706,000. Clearly, if PG&E upgrades the line at their cost, or the developer pays for the line upgrade, these costs would be zero from the SFPUC perspective. The least expensive alternative with RDG would have a lifecycle net cost of $2,783,000 and a difference of $2,075,000 over the life of the project.

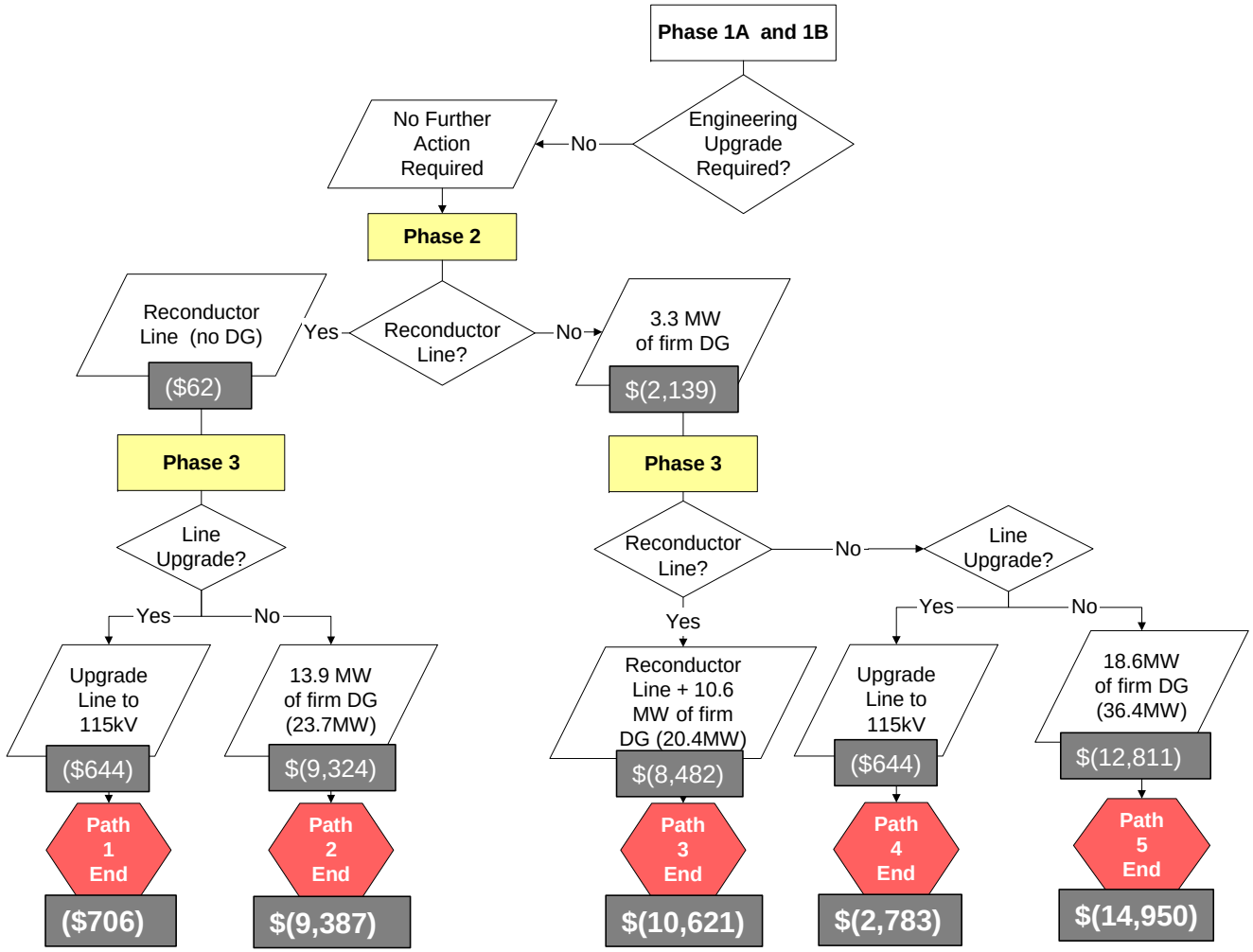

Figure 68: Utility Cost Test (UCT) Results for 5 Investment Paths at the HPNS (with energy efficiency). Costs are shown in 000s. RDG solution includes a baseload 800kW biogas-reciprocating engine operating with CHP (80$) and a peaking 100kW Polysulfide flow battery (20%)

Given the relatively narrow $0.008/kWh gap in cost-effectiveness, we evaluated the key input variables to determine which inputs are most important to the outcome. Figure 69, below, shows the range of net benefits for each important variable. The total shortfall in net benefits with base-case assumptions is $495/kW of installed RDG. With a change from the base-case in generation market prices (market prices are higher), transmission costs (transmission prices are higher), or fuel (lower fuel prices), the installation becomes cost-effective. A 20% change in capital costs or capacity factor does not result in cost-effectiveness, all other factors being equal. Therefore, while a SFPUC biogas generator with CHP is not cost-effective in the base case, this economic screening analysis indicates that it is relatively close to cost-effective and more detailed pro-forma analysis may be warranted to further evaluate the project. This is especially true if indirect benefits are attributed to developing more renewable generation within the City.

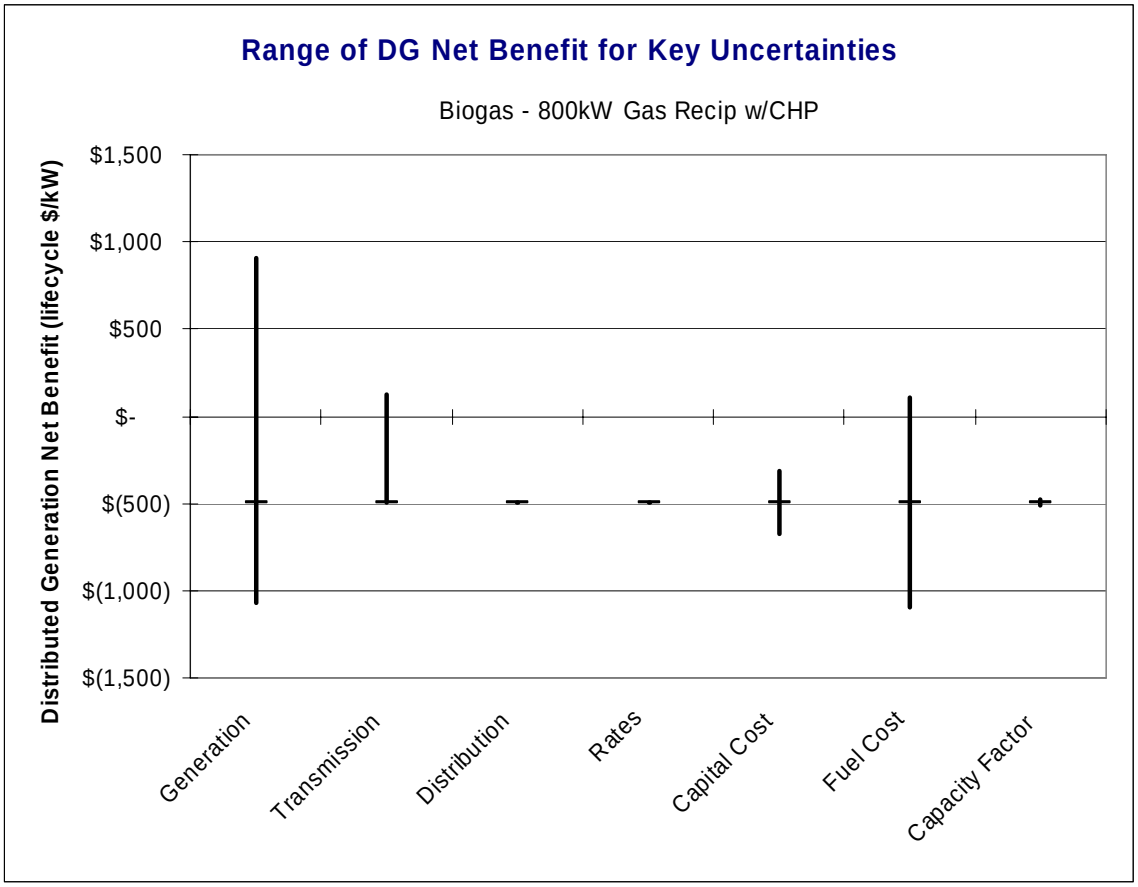

Figure 69: Range of DG Net Benefits for Key Uncertainties (800 kW Recip Engine with CHP operating with biogas fuel)

5.0 Reliability Analysis

The analysis of DG for the HPNS redevelopment presents many interesting challenges. The objective is to reliably supply electrical power to the development without adding significant demand to the existing PG&E power delivery network and requiring new lines. As far as possible, the load demand is to be met with renewable DG. This increases the challenge because some types of renewable DG are not dispatchable and cannot easily supply reactive power, a necessity for good power quality.

The development of four parcels, designated A, B, C and D, is to take place in three major phases. The first phase is split into two, designated herein as Phases 1a and 1b. Rooftop solar photovoltaic (PV) generation will be employed extensively in the first two phases.

The area is currently fed by an overhead 12 kV line from the substation at the Hunters Point generating plant. One of the key limiting factors is the rating of this line. For this study, it is assumed to be 8 MW. The amount of DG capacity – both active and reactive power - required to supplement the solar PV generation and prevent overloading of the line for each phase of the development has been computed from annual simulations of the proposed system. For Phases 2 and 3 the results were also computed assuming the 12 kV service to the Shipyard could be upgraded to 12 MW from 8 MW. The results are summarized in Table 27.

Table 27: Summary of Minimum Supplemental DG Requirements

Phase	Incoming Line Limit	Peak Generation Required (MW)	Equivalent Capacity Factor (%)	Peak Reactive Power Required (Mvar)
1a	8 MW	0	----	0
1b	8 MW	1.8	1.0	1.6
2	8 MW	12.9	25.4	8.2
2	12 MW	9.0	8.7	6.6
3	8 MW	30.9	41.8	18.3
3	12 MW	26.9	36.2	16.7

Phase 1a (Parcel A) can be implemented without supplemental DG. The existing line should have sufficient capacity to support this phase of the development. The reliability of the system at this phase is identical to the existing system because it is assumed the solar PV generation will require the utility supply to operate. The 1800 kW of solar PV generation would be expected to provide a significant percentage of the energy required in this phase.

At the end of Phase 1b (Parcels A and B), the load will exceed the capability of the existing line by 1.8 MW despite having a total of 3100 kW of solar PV generation. In addition, 1.6 MVAR of reactive power generation will be required. This generation is required only a few hours per year in the winter months when the solar PV generation is ineffective. The additional generation would be required to have a capacity factor equivalent to only 1% of the 1.8 MW rating. The requirement can be met by operating approximately 100 hrs per year, with a maximum of approximately six hours on the peak load day. This can be achieved by readily available inexpensive peaking generators. It can also be accomplished by storage. The primary reason supplemental DG is needed is that the solar generation lacks a few hours of completely compensating for the peak load, particularly when the days are shorter. A key requirement is that the supplemental generation or storage must be dispatchable.

The reactive power requirement does not necessarily correspond to the active power demand, which suggests that the reactive power demand be supplied separately from the active power generation. This can be accomplished by switched capacitors or special inverters on the renewable DG specifically designed for the purpose of supplying reactive power.

The dispatching of the DG (both active and reactive power) will require some sort of energy management system installed as part of the Phase 1b development. This is necessary to prevent the incoming line from being overloaded. The simulations suggest that it is not practical for local intelligence on DG devices and reactive power sources to determine the proper dispatching. It would make sense to install this system at the time the new underground feeders for the development are constructed.

The role of the energy management system becomes crucial as the development proceeds into Phase 2 (developing Parcel C). The system would have to control a minimum of approximately 13 MW of DG, which is at least 5 MW more than the capacity to deliver power from the utility source. To achieve reliability comparable to the existing wire delivery reliability will be a challenge. Recovery from system faults requires a sequence of steps to prevent overloading and to match generation with the load as the load is brought back on line. The prevention of nuisance generator trips that often plague DG applications will be of high importance. If the utility supplied power can be increased to 12 MW, the minimum required DG is reduced by 4 MW and the amount of time that the dispatchable DG would have to operate is reduced from an equivalent of 25% to about 9%.

The same trends continue into Phase 3 development in which over 30 MW of dispatchable DG would be required.

The values shown in Table 27 are minimum values required. In practice, the DG capacity required to operate successfully would be 150% to 200% greater to allow for generator downtime and to achieve the capacity necessary to handle load inrush and step load changes with adequate power quality. In our analysis of the economics of DG,

we have included an estimate of the additional DG required to achieve the 'firm' capacity for the HPNS.

An alternative to supplying the load with DG is to build a new 115 kV/12 kV substation at the entrance to the Shipyard. While this could resolve the basic capacity issues, it is not without reliability issues. Building a single radial feed to the substation could result in extended outages, especially if it is buried without conduit. Constructing a redundant feed would be expensive.

5.1. Description of Development Phases

The redevelopment of the HPNS studied here consists of four parcels of land referred to as parcels A, B, C, and D. The first phase of development will occur on Parcel A. Subsequent phases will continue the development on Parcel A and the development of the other parcels.

Beginning at the entrance to the HPNS development, a new underground feeder system is proposed. Twelve underground feeders will branch out from this point, which could serve as the site for a new substation at some time during the development process. These feeders will replace the existing overhead lines that serve the HPNS. Initially, the feeders will be served from a single 12 kV line from the existing Hunters Point substation. The geographic topology of these feeders relative to the existing Hunter's Point substation is illustrated in Figure 70. Each feeder is shown in a different color. A computer model was developed from the Newcomb Anderson Associates Overall Site Plan[17].

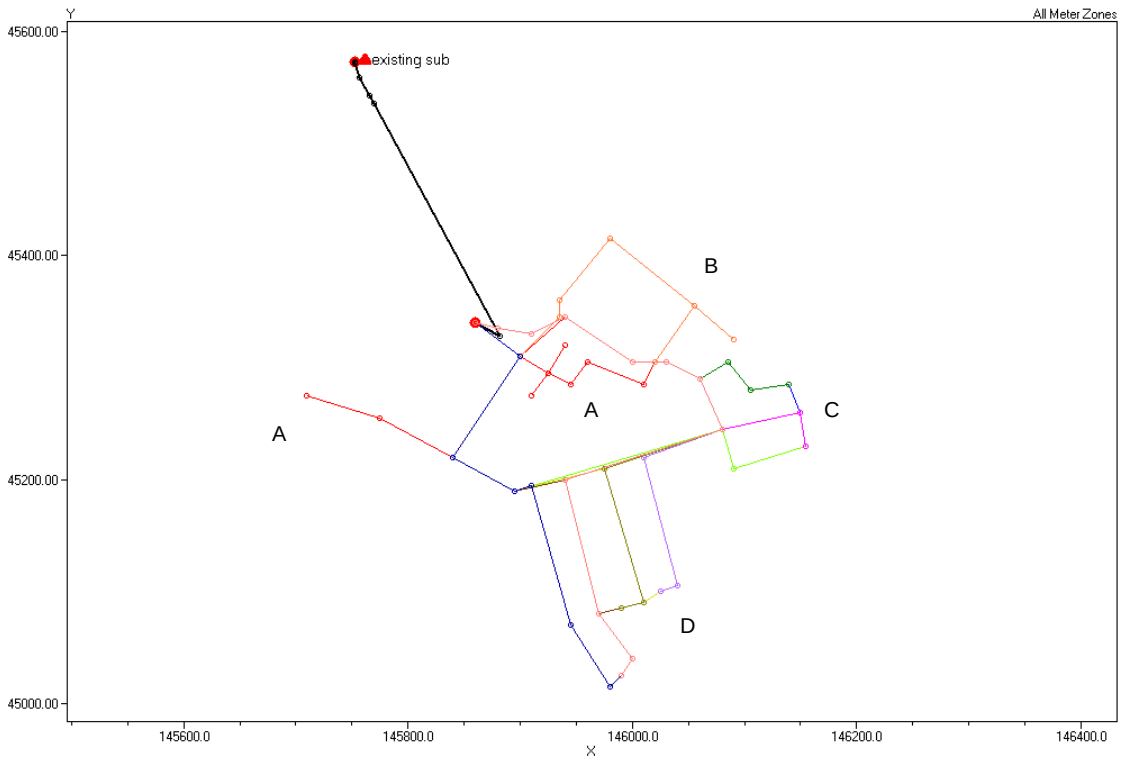

Figure 70: Locations of Hunters Point Underground Feeders

[17] Newcomb Anderson Associates, Overall Site Plan, Hunters Point Switchyard, Dwg E-2.2, October 13, 2003.

The peak load projected for each parcel is shown in Table 28 along with the total for each phase of the project. These figures were derived from the load forecast study by Newcomb Anderson Associates and modified to account for the energy efficient features proposed for the housing units at Hunters Point.[18]

Table 28: Loading Projected for Each Parcel

Parcel	Peak Load	Total Accumulated (kW)
A	4522 kW	4522
B	4597 kW	9119
C	11546 kW	20665
D	17774 kW	38439

The incoming line from the existing Hunter's Point station has an assumed capacity of approximately 8.3 MVA. This is sufficient to serve the first part of Phase 1 development (Parcel A). However, additional supply capacity will be required to meet the projected peak demand for all remaining phases.

5.2. System Load Characteristics

The load shapes were developed by studying the plans for the development of the HPNS and comparing with load data for another Bay Area community with similar makeup. The loads were modeled by defining a base load for the residential and commercial facilities. The rooftop solar PV generation was then added as negative load following the solar output pattern for the area.

The annual energy consumption profile assumed for Parcel A is shown in Figure 71. This is similar to the peak demand profiles shown in the corresponding Engineering Screening Analysis chapter. Each point on the plot corresponds to the energy consumed in that hour for all the days in a given month.

[18] Newcomb Anderson Associates, HPS Electric Service Evaluation, Task 5 Deliverable – Technical Memorandum for Preliminary Load Forecasts, Letter to Mr. Sam Larano, Hetch Hetchy Water and Power, August 5, 2003.

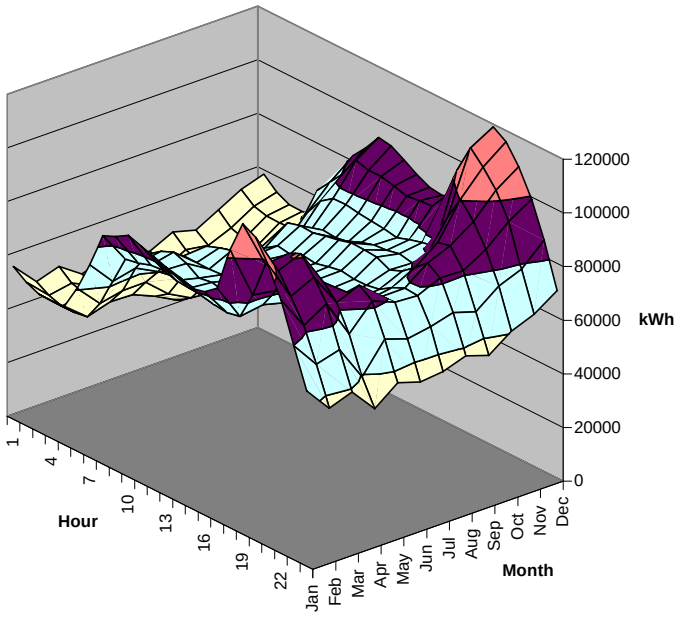

Figure 71: Annual energy load shape assumed for Parcel A

When the solar PV generation characteristic (Figure 72) is included with the load characteristic, the reduction in energy drawn from the PG&E line during the mid-day is quite obvious (Figure 73). Figure 73 includes existing loads on Hunters Point that are assumed to be transferred to the new feeders. Thus, the maximum hourly energy consumption is greater than for Parcel A alone.

This gives a good idea of the impact of the solar PV generation in terms of energy consumption. The impact on reliability is still an open question because the solar PV generation requires the presence of the utility feed to operate. The value of reduced loading on the incoming line cannot be evaluated without detailed knowledge of the characteristics of the utility supply system. The other issue that is apparent from this figure is that without storage to extend the output of the solar DG, the peak demand remains largely unchanged.

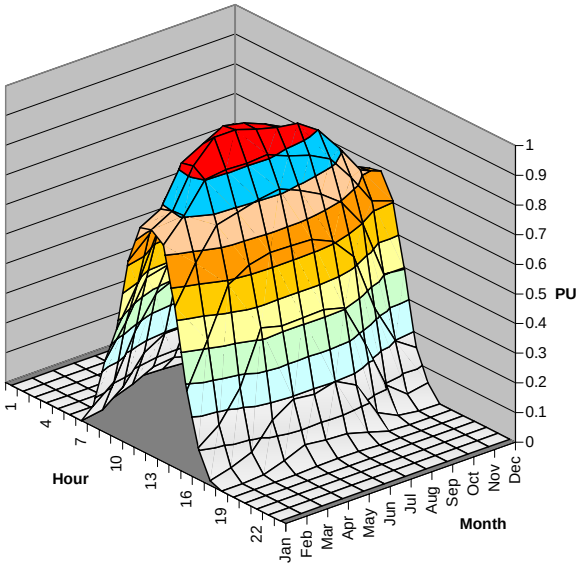

Figure 72: Assumed solar PV power output shape (per unit)

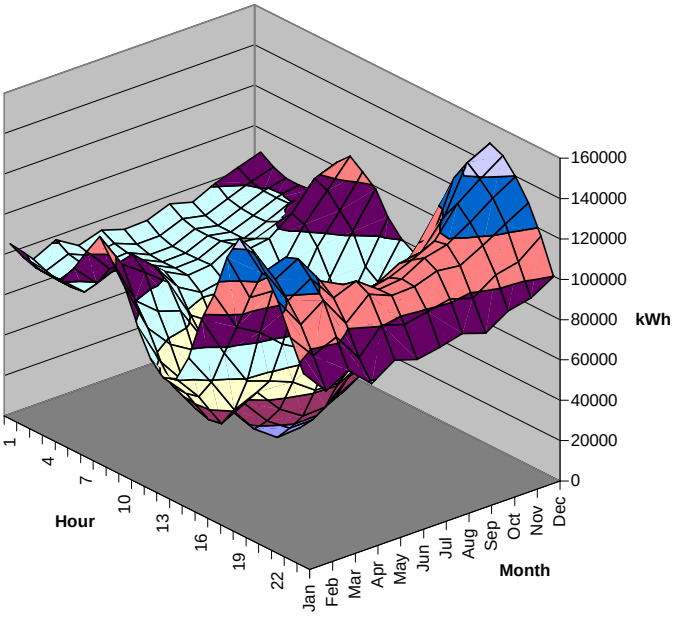

Figure 73: Net energy from PG&E after Parcel A buildout with 1800 kW solar PV

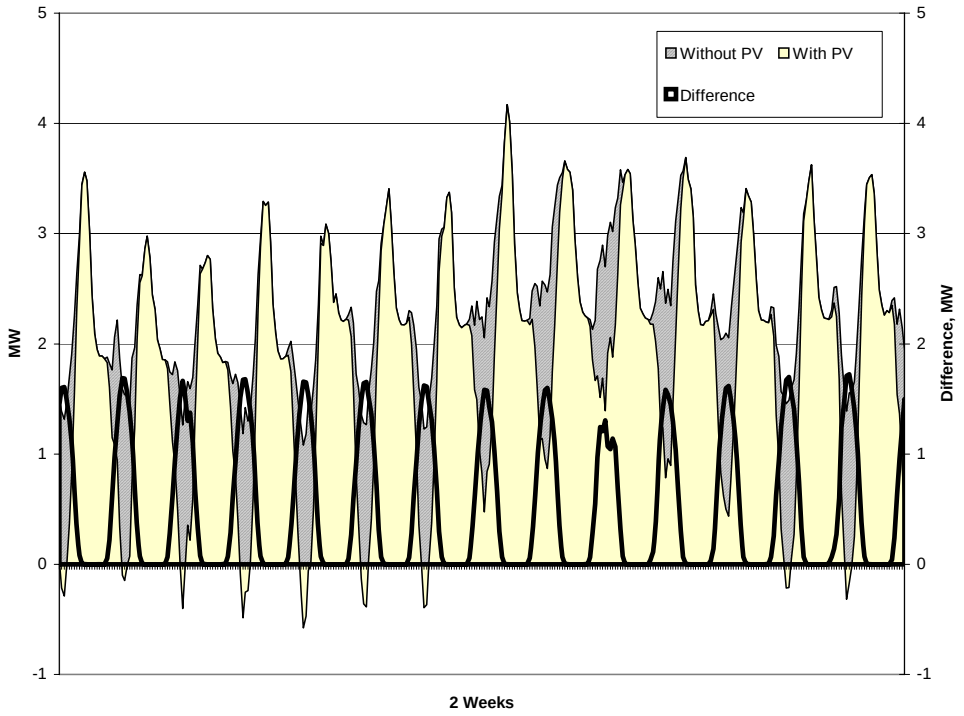

Figure 74: Impact of 1.8 MW solar PV generation on the kW demand from the incoming PG&E line during two weeks in summer (Phase 1a)

Figure 74 illustrates the impact of the solar PV generation on the kW demand from the utility system in another way. This shows a two-week period during the summer. The cross-hatched area in the background shows the base load demand without considering the PV output. The solid filled area (yellow fill) shows the net in the incoming 12 kV line while the dark curve shows the difference, or the solar PV output. Where the crosshatched area shows through, the solar PV output is canceling out the load demand. At some times on light load days, the 1800 kW of solar PV generation assumed installed during Phase 1a would be expected to exceed the load demand and result in a net negative power flow in the line.

5.3. Reliability Evaluation

The reliability analysis in this case differs from that performed for the other three cases in this DG Assessment Project 3.1. In those cases, the utility power delivery system remained dominant and the DG options considered were supplemental. Therefore, the problem was to estimate the impact DG would have on the reliability of the system as the load grows. The topology of the distribution system was important because DG could impact the ability to restore the system after the failure of a key line or transformer. In this case, it is proposed to support the redevelopment of the HPNS

mostly by DG in the later phases without constructing new power delivery facilities from the surrounding utility grid.

There are so many feeders (12) in the Newcomb Anderson Associates approach that the impact of the DG is likely inconsequential to the feeder reliability. Each of the individual feeder branches is moderately loaded and it can be expected that switching to pick up loads out of service from a fault within the development can be accomplished easily with or without DG. The capacities are not sufficiently taxed to the point where the presence of DG, or lack thereof, is likely to make much of a difference. This is in contrast to other cases studied in this project where DG can free up sufficient capacity to potentially make an improvement in the reliability.

Up through Phase 1 (Parcels A and B), the reliability of the system is basically unchanged from the present. The chief DG proposed is rooftop solar PV generation. While the DG capacity is significant (3100 kW), this type of generation would typically require the presence of the utility supply in order to operate. Therefore, when the incoming PG&E line is not energized, the HPNS will be without power, which would be the situation with, or without, DG. Thus, the DG would not improve the reliability for the end users by providing backup power. The other major issue is restoring the system after a fault. All the DG will disconnect at the time of the fault leaving all the load on the incoming feed.

Toward the end of Phase 1, the load is projected to exceed the assumed rating of the incoming line by less than 2 MW a few times during the year. This deficit can be handled by any of a number of relatively inexpensive peaking generator solutions. It is also conceivable to address this deficit with storage that is charged during off peak times. Another option is to undertake a modest load curtailment program to get through the anticipated peaks. In either case, an energy management system of some sort will have to be employed to monitor the situation so that feeder restoration can take place in an orderly fashion and that the incoming line is never overloaded. It should be practical to install such a system at the point where the incoming PG&E line connects with the feeders proposed in the Newcomb Anderson Associates design.

Reliability becomes a more serious issue once significant supplemental generation becomes necessary in Phase 2. This concern would continue into Phase 3 development. When there is a short circuit fault on the system, all the generation and the utility source must disconnect to stop the arc, permitting the fault to clear. Starting back up can be a challenge. The utility breaker can be closed back in quickly, but the utility line cannot pick up all the load. Therefore, the load will have to be re-energized in segments coordinated with the dispatchable DG.

A possible sequence is:

1. Re-energize the utility feed and part of the load (probably the residential feeders from Phase 1);
2. Start some of the dispatchable DG – enough to cover the next segment of load;

3. Re-energize the next segment of load; and
4. Repeat steps 2 and 3 until all the load is restored to service.

In general, the rate of actual faults on the West Coast is low compared to the rest of the USA due to the relatively low incidence of severe storms. So this scheme should work as well in this area as it could anywhere. There are some concerns, however.

One concern is to minimize the nuisance DG trip rate. This is a problem for all types of DG operated in parallel with the utility system, particularly in the initial months after installation until all the minor bugs are worked out. While fault rate may be low in a given part of the system, there are generally several transmission system faults each year that cause voltage sags over a wide area. Depending on transmission voltages, sags due to faults hundreds of miles away are sometimes observed on local distributions systems. The relaying on the DG may interpret the event as a fault for which it must disconnect, resulting in a nuisance trip. Also, there are a myriad of problems with fuel quality, component failures, and the like, that cause DG devices to trip off. Some of this must be expected. To compensate, there must be a substantial amount more DG capacity installed than the expected demand for it and a control system must be designed to take quick corrective action should inadvertent generator tripping leave a significant deficit in the supply.

There must also be more DG capacity installed than load to accommodate the load inrush when restoring load after an outage. This should not be a problem for Phase 1, but it would not be far into Phase 2 before the problem would appear. A rough rule of thumb for rotating machine generation is to have twice the rated kVA capacity as the maximum expected step change in demand in order to start motor load without causing excessive voltage sags. Inverter-connected DG is apt to be more of a problem and the amount of operating experience with inverters in this regard is light. Ongoing microgrid research might provide some insight into how to better handle this situation without adding large amounts of excess capacity.

A final concern we will point out is with the HPNS system specifically. As has been discussed, the reliability of the system for Phases 2 and 3 will be low if there are many faults on the local system that result in sustained interruptions. The inherent delay in restoring the system using the sequence described above will increase unserved energy indices over what they would be if all load were served conventionally. Therefore, fault prevention is a high priority. The new feeder cables in the development itself are specified to be installed in conduit. This should greatly reduce the exposure to faults and result in satisfactory delivery reliability once the power reaches the HPNS. The weak link is likely the line from the existing substation to the point of interconnection on the new development.

Figure 75 is a photograph of a portion of that line near the substation at the Hunter's Point power plant. It is a typical overhead double circuit line, which is common throughout the USA. Two things in this photograph would give some concern to distribution engineers seeking a design for a line with higher-than-average reliability:

1. The presence of trees and the congestion with other overhead line structures in the vicinity (there are others directly behind the camera position as well) which creates more opportunities for faults.
2. The proximity of the wood poles to the roadway. The presence of reflective stripes on the pole suggests a history of, or concern for, automobiles striking poles. This is a major cause of interruptions in urban areas with such structures.

These concerns could largely be negated by burying the 12 kV line. The cost to bury 3-phase distribution cable in urban areas currently averages more than $1M per mile plus terminal equipment. The distance here would appear to be approximately 0.25 mi. The determination of whether it is economical to make this investment to protect the HPNS development load from faults would depend on the historical outage rate on the line.

Figure 75: A Portion of the Existing 12 kV Feed to Hunters Point Looking Toward the Substation at the Hunters Point Power Plant

In summary, we conclude that there will be little difference from the present in the reliability of the power service to the HPNS for the first phase of the redevelopment. As the redevelopment nears the end of Phase 1, a relatively minor amount of peaking generation, storage, or load curtailment may be required to maintain that reliability. To go beyond Phase 1, a sophisticated energy management system will be required along

with dispatchable DG to coordinate power requirements with the incoming utility line so that it is not overloaded and to manage the restoration of the system after faults. The minimum amount of DG required to supply the load is determined as described in the next section of this report. Keep in mind that more DG capacity would be required to provide for generation outages and for minimizing operating problems during system disturbances.

The potential operating difficulties can also be mitigated somewhat by strengthening the tie to the local utility grid. Two scenarios are considered later in this report:

1. Strengthening the existing 12 kV supply from 8 MW to 12 MW. If there is to be investment to increase the reliability of the line, one may as well upgrade its capability.
2. Constructing a new 115/12 kV substation at the Hunters Point Shipyard. It is assumed that this substation can be sized to eliminate all capacity issues. However, there are still some reliability concerns to be addressed.

5.3.1. Minimum Required Supplemental DG

The minimum amount of DG, in addition to the solar PV generation specified for the various parcels, required to support the projected load was determined. Figure 76 illustrates the computer model used for this analysis.

The model was based on the DSS computer program model established from the circuit drawings in the Newcomb Anderson Associates drawings as described previously. The assumed solar PV generation was embedded with the load model. Finally, it was assumed there was sufficient dispatchable DG present at the HPNS to supply the deficit between the load demand and the capability of the incoming line. Then annual simulations were performed using the assumed load shapes for each phase of the redevelopment. The dispatchable DG was dispatched to eliminate the deficit in active and reactive power for each hour.

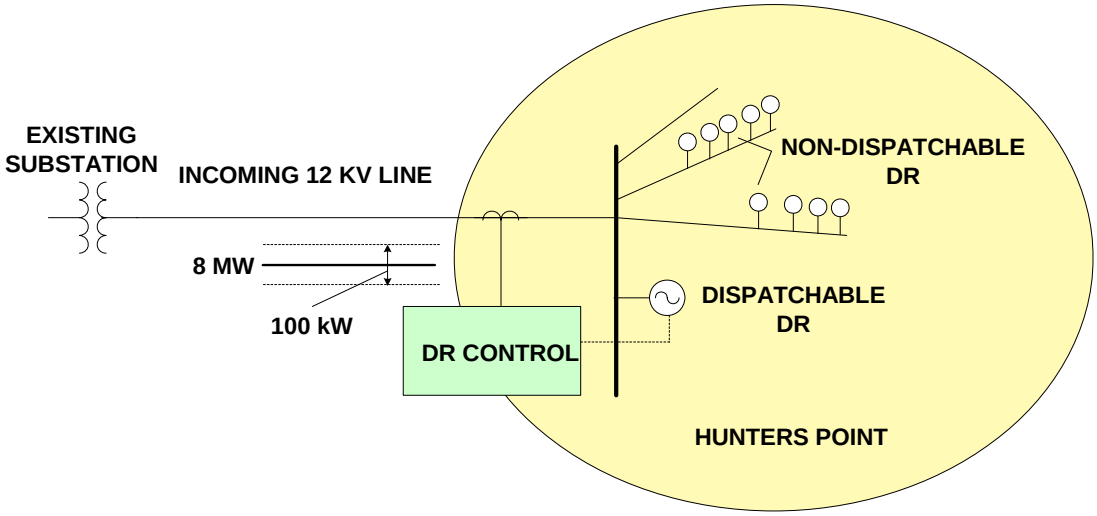

Figure 76: Model Used to Determine Minimum DG Requirements to Meet Projected Hunters Point Shipyard Loads

The dispatchable DG was assumed to be lumped at the bus where the 12 feeders meet. A test was also made with the generators distributed among the feeders, but the difference in the results was inconsequential because each of the feeders is relatively short for the load it is carrying. Therefore, the single generator model was used for simplicity.

The dispatch of the DG is determined simply to prevent overloading of the incoming 12 kV line. It was assumed that the line was rated at 8 MW. A simple deadband controller was modeled to dispatch the DG active power. A bandwidth of 100 kW was used. If the line loading was projected to exceed 8050 kW, the DG power output was increased to bring the loading back to approximately mid-band. Conversely, if the line loading was projected to be less than 7950 kW, an attempt would be made to decrease the DG output by an amount to return the line loading to mid-band. The DG output was not permitted to drop below zero (consuming power). Thus, the resulting DG output characteristic gives the minimum amount of active power production required to meet the projected load while not overloading the incoming utility line.

Obviously, a more intelligent control could be devised that could also take into account the status of resources within the HPNS development to optimize the economic dispatch. This simple dispatching model was employed because it worked very well in the annual simulations without causing solution convergence difficulties. It quickly yields a useful estimate of the minimum amount of DG required to support the load.

The active power requirement gives only part of the answer concerning the amount of DG needed. Reactive power will be a serious issue because many renewable DG technologies do not typically produce significant reactive power while operating in parallel with the utility. However, there will still be a reactive power requirement to compensate for the current flow in the lines and the power factor of the loads.

It was initially thought that the reactive power requirement could be determined simply by maintaining a predetermined voltage at the HPNS. However, this proved unreliable, possibly due to the relatively short distances involved. Minor changes caused widely divergent results and resulted in overloading the line although the active power in the line was within the desired band. Therefore, the reactive power requirement was also determined by employing the simple dead-band controller model for dispatching the reactive power. It was assumed that the rated current in the line was 416 A based on a similar line design on file. This results in a reactive power limit of 3280 kVAR. A 100 kVAR bandwidth was assumed.

For Phase 1a, this model yields zero for the minimum DG requirement because the entire load can be served from the incoming line. The first interesting phase is Phase 1b where the loading exceeds the line rating for approximately 100 hours. The computed DG requirement for the year is shown in Figure 77.

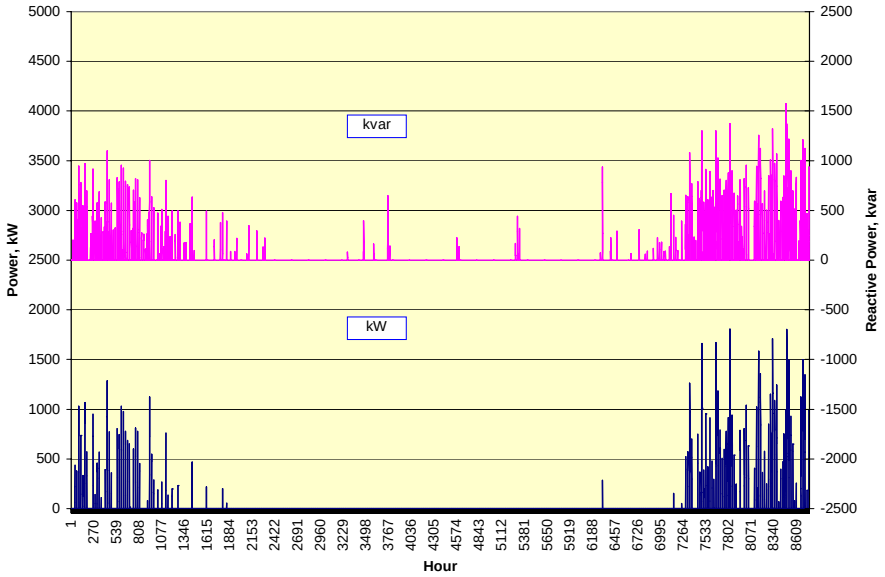

Figure 77: DG kW and kVAR output required for Phase 1b to maintain incoming PG&E line below 8 MW and 3.3 Mvar

This chart shows that the minimum active power requirement is approximately 1800 kVAR and the reactive power requirement is approximately 1600 kVAR. While there is generally good correlation between the Watt and VAR requirements, they are not necessarily coincident. Although this requirement might be met with a single dispatchable synchronous machine generator, a reactive power source that is separate from the active power source might be desirable.

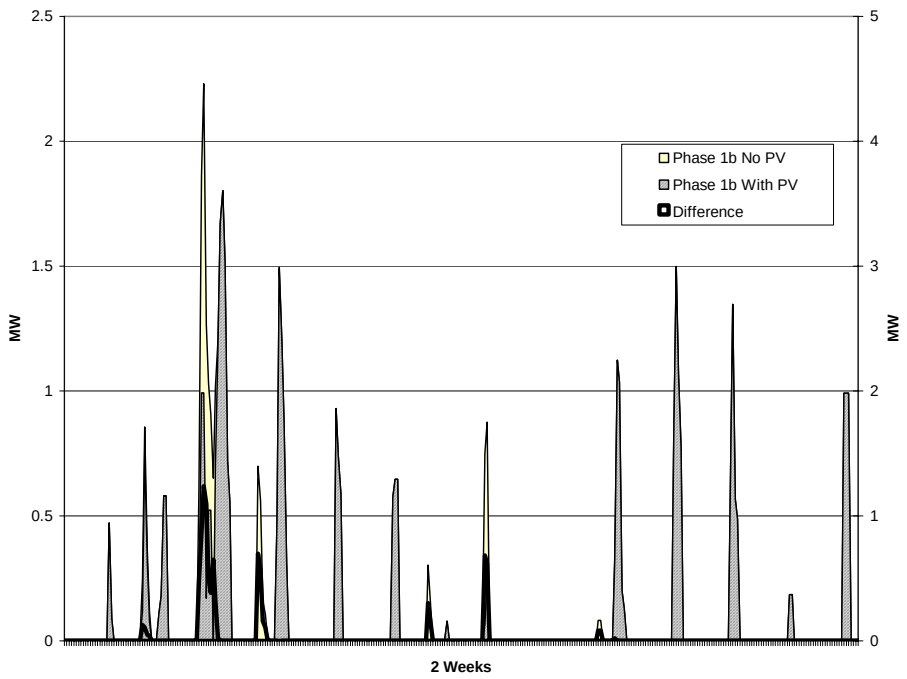

Figure 78: Comparison of minimum supplemental DG requirement with and without the solar PV for two weeks during winter peak illustrating the expected coincidence of load and generation (Phase 1b)

This model also produces some interesting results that yield insight into some of the difficulties of attempting to meet firm load demand with renewable generation. Figure 78 shows an overlay of simulation results for a two week period around the winter peak for the Phase 1b case with and without solar PV generation. The cross-hatched area shows the requirement for the case with 3100 kW of PV generation installed. Where the solid (yellow) shaded area shows through, the PV is effective in reducing the loading on the incoming line. The PV output is the difference curve (heavy black line). For several days in this period, the solar PV generation is not effective and the difference must be covered by some sort of dispatchable generation.

For Phase 1b, a 1.8 MW generator would have to operate the equivalent of 93 hours per year at full power to satisfy the required energy with the longest dispatch on the peak demand day being the equivalent of six hours of continuous operation at full power. The shape of the annual dispatch characteristic is shown in Figure 79 and Figure 80. The former shows the maximum power dispatch required for a given hour in a month. The latter shows this characteristic in terms of the *energy* required from the DG to meet the requirements imposed by the incoming line limits. This shows that the generation would be expected to operate mostly from 5 PM to 8 PM in the months of November through February.

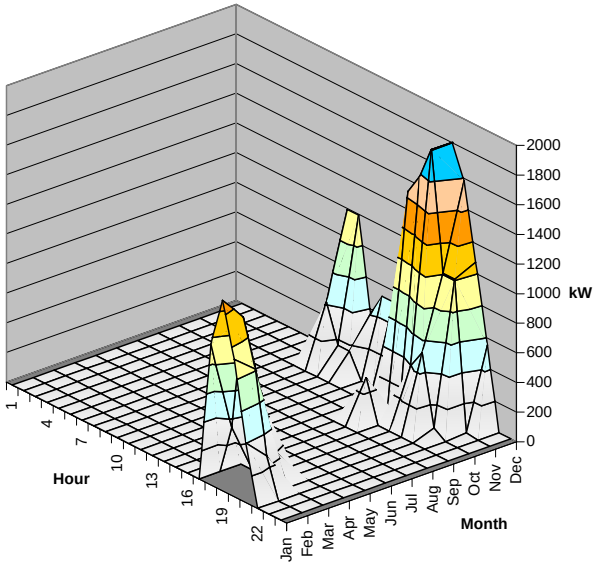

Figure 79: Annual shape of DG hourly peak power output required to keep the loading on the incoming line less than 8 MW for Phase 1b

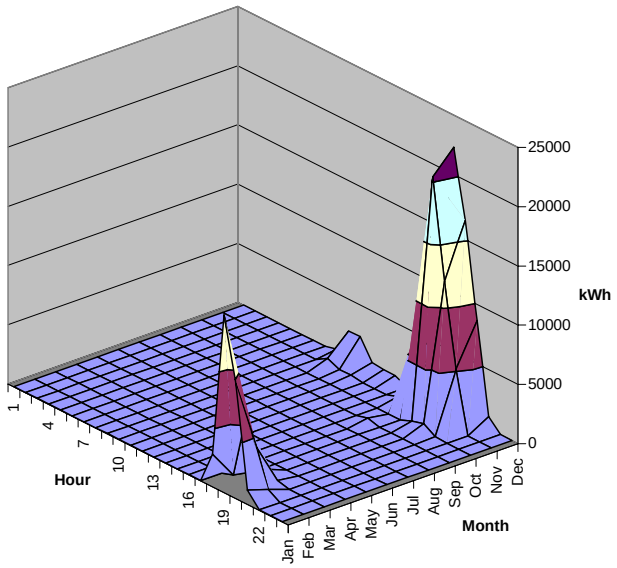

Figure 80: Annual shape of DG hourly energy (kWh) output required to keep the loading on the incoming line less than 8 MW for Phase 1b

5.3.1.1. Results for Phases 2 and 3

The next series of charts shows the results of the minimum required DG simulations for Phases 2 and 3. Table 29 provides a concise summary of these results. There is a quite

significant deficit that must be made up by DG in each of these phases. Supplemental DG would be expected to operate nearly all the time at some level except perhaps during the summer. The average power output is indicated by the Equivalent Capacity Factor in the table.

The first chart in each series shows the 8760 dispatch required for kW and kVAR. The next two charts show the 3-D annual profile plots for these results with the first being the peak power for the hour and the second being the total energy for the hour. The fourth chart shows the 8760 dispatch characteristic assuming the incoming utility line can be upgraded to 12 MW instead of being limited to 8 MW.

Table 29: Summary of Phase 2 and 3 Results

Phase	Incoming Line Limit	Peak Generation Required (MW)	Equivalent Capacity Factor (%)	Peak Reactive Power Required (Mvar)
2	8 MW	12.9	25.4	8.2
2	12 MW	9.0	8.7	6.6
3	8 MW	30.9	41.8	18.3
3	12 MW	26.9	36.2	16.7

Equivalent capacity factor = (total kWh req'd)/ (Peak generation req'd)

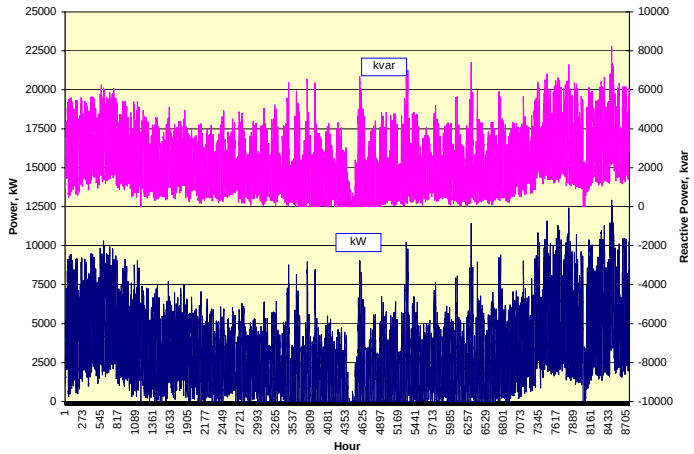

Figure 81: DG kW and kVAR output required for Phase 2

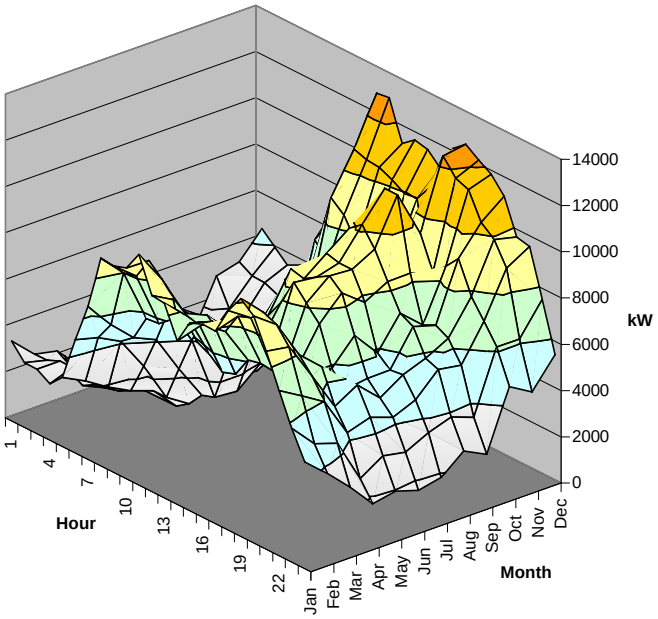

Figure 82: Annual shape of DG hourly peak power output required for Phase 2

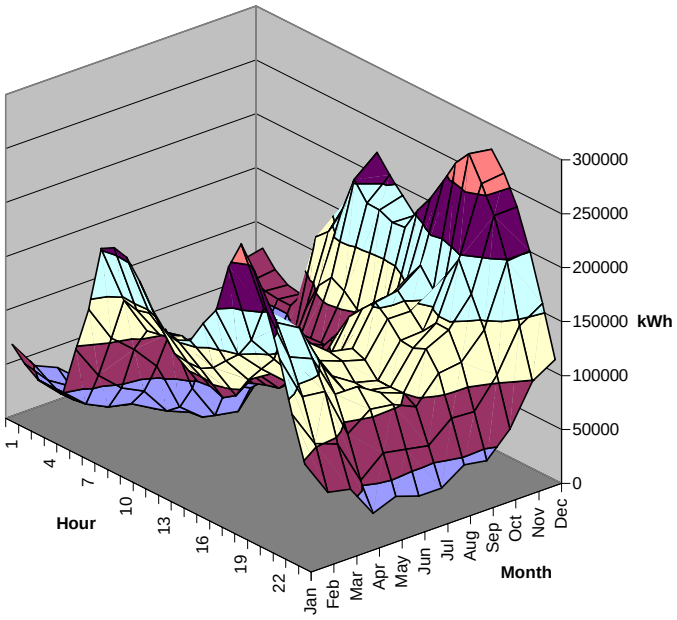

Figure 83: Annual shape of DG hourly energy (kWh) output required for Phase 2

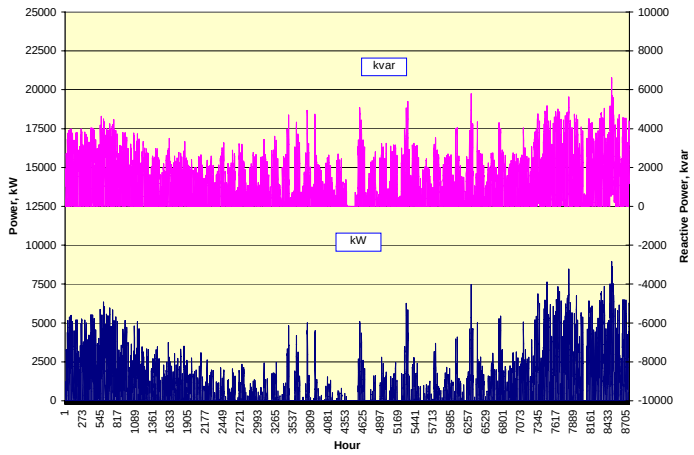

Figure 84: DG kW and kVAR output required for Phase 2 assuming incoming PG&E line can be upgraded to supply 12 MW

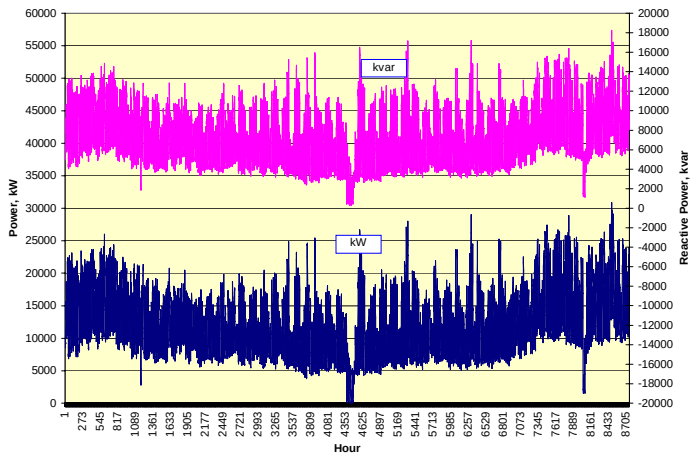

Figure 85: DG kW and kVAR output required for Phase 3

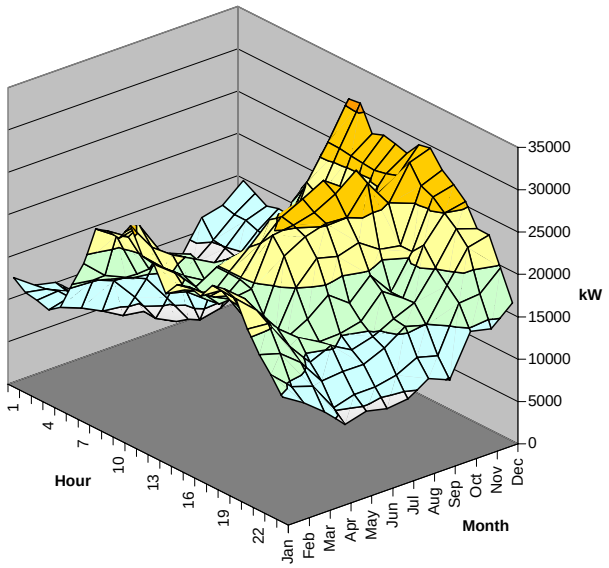

Figure 86: Annual shape of DG hourly peak power output required for Phase 3

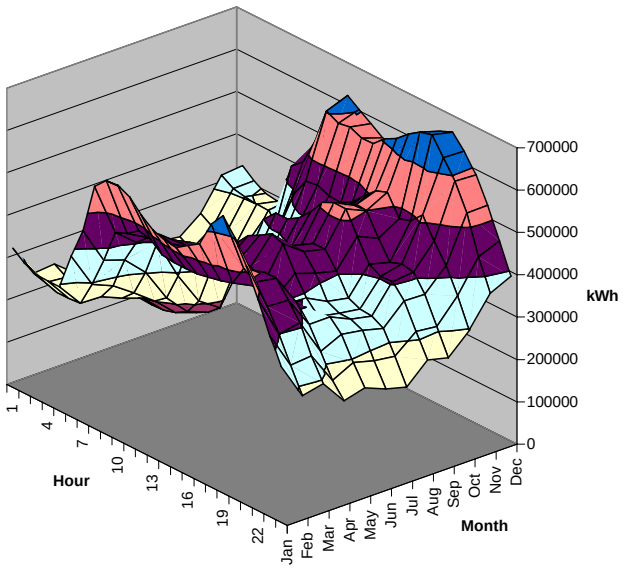

Figure 87: Annual shape of DG hourly energy (kWh) output required for Phase 3

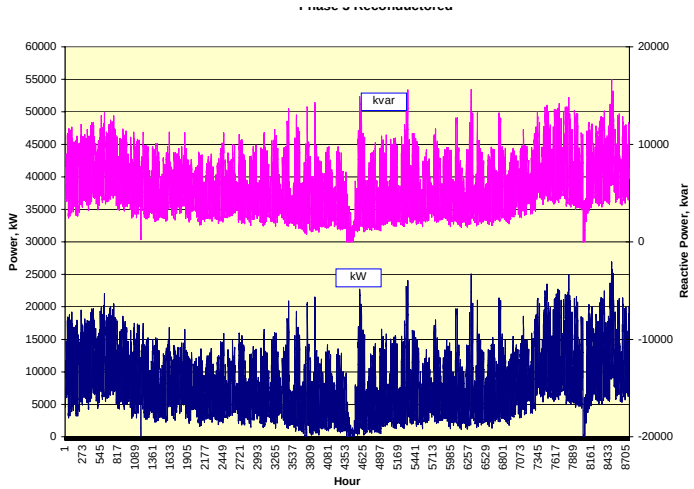

Figure 88: DG kW and kVAR output required for Phase 3 assuming incoming PG&E line can be upgraded to supply 12 MW.

5.3.2. Summary: DG Minimum Requirements

Table 30 provides a summary of the computed minimum supplemental DG requirement for each phase of the development along with the peak load expected for that phase.

Table 30: Summary of Loading and Minimum Required DG Capacities for the Various Phases of the Hunters Point Development (based on 8 MW limit on incoming line)

Phase	Parcels	Peak Load (kW)	Min. Req'd kW	Min. Req'd kvar
1a	A	4522	0	0
1b	A+B	9119	1805	1573
2	A+B+C	20667	12918	8223
3	A+B+C+D	38441	30856	18266

It should be re-emphasized that these represent the *minimum* additional DG required to serve the load for each of these phases. To achieve satisfactory reliability, the rated capacity of the DG devices will likely be 50-100% higher depending on the number of units and the expected step load changes the system would be expected to accommodate.

For example, the 1805 kW requirement of Phase 1b can easily be met by a single generator rated approximately 2 MW. These are readily available and leasing one for the winter months is a likely economic solution to meeting this projected deficit.

However, the generator is absolutely required to meet the load demand without shedding load. Therefore, it would generally be advisable to have two such units to better ensure that at least one comes on. Alternatively, one may choose to acquire three 1-MW units to allow for the contingency of one failing to operate.

For Phases 2 and 3, the situation is more complicated and will depend on the mix of generation added as the development progresses. However, it would not be unreasonable to expect that the required DG capacity to reliably meet the load to be approximately 20-25 MW for Phase 2 and 35-60 MW for Phase 3 depending upon the DG coincident output and local load growth. Much of that additional generation would have to be dispatchable to better match load and demand. The incoming line would permit a swing of only +/- 8 MW.

5.4. 115 kV Substation Option

Another approach to handling the load demand for Phases 2 and 3 is to construct a new 115 kV/12 kV substation on the HPNS site with sufficient capacity to handle the 40 MW of load anticipated for the final phase of development. This would also allow a greater variety of renewable DG to be utilized in the redevelopment without operating concerns. The feeders specified in the Newcomb Anderson Associates report would be connected to 12 kV at the substation site. While this appears to be a straightforward solution, there are some subtle reliability issues with respect to this particular site.

Two options for supplying such a substation from the existing 115 kV system are illustrated in Figure 89. Figure 89(a) shows a simple radial feed from what appears to be a nearby 115 kV cable terminal (Figure 90) to a possible substation site on the edge of the HPNS area. This would certainly be the simplest way to serve such a substation if it can be accomplished. The least costly line would be an overhead line. It may be tempting to require burial of the line – many, if not all, of the 115 kV lines coming into this area appear to be buried in the vicinity of Hunters Point. A portion of the cable path may have to be submarine cable depending on the exact route selected. This can be 3-10 times more expensive than building an aerial line. While this may be aesthetically more acceptable, the downside of constructing a simple radial feed with buried cable is that when there is a cable failure repair times are quite lengthy. This is particularly true if part of the line is submarine cable. In contrast, an overhead line might be typically repairable in 2-3 hours.

Without sufficient backup resources, this would mean that most of the load on the HPNS development would be unserved during the repair time for Phases 2 and 3.

To get around this reliability problem, one could bury two 115 kV cables in separate trenches to the substation site. One plan for configuring the lines is shown in Figure 89(b). Besides the extra cable, there is considerably more switchgear (represented by the squares) involved. Thus, this option is considerably more costly than the simple radial feed.

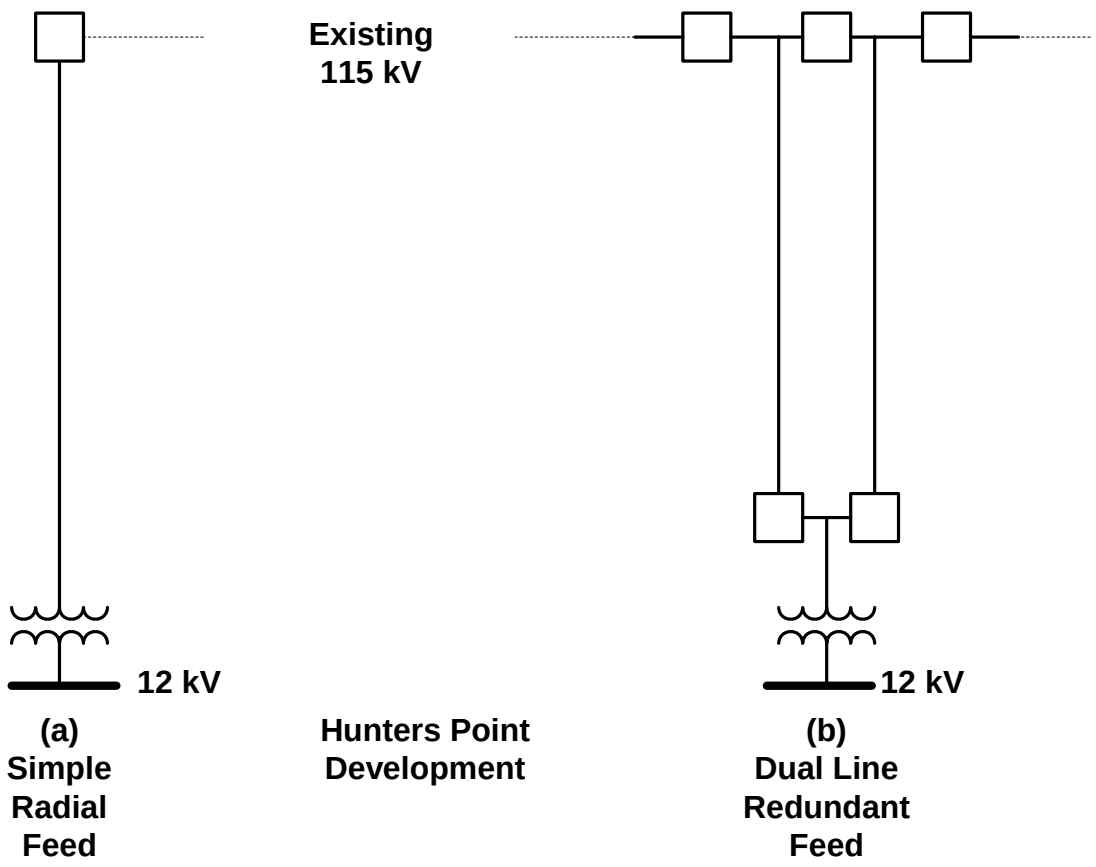

Figure 89: Two Options for Supplying a New 115 kV Substation for the Hunters Point Redevelopment Project

Another option for achieving shorter repair times for a simple radial feed with buried cable is to install the cable in conduit rather than direct burial. The distance is relatively short – perhaps, a few hundred meters, so this might be possible. When the cable suffers a failure, it is more easily replaced. Of course, using a conduit approach will also add considerable expense to the project.

The typical estimating cost of the substation equipment alone is commonly at least $10/kVA. Thus, a 50 MVA substation might be expected to cost at least $500,000. Cable and site preparation costs would likely escalate that cost to a few million dollars.

This analysis assumes that there is adequate capacity in the 115 kV loop to tap off another 40 MW.

Figure 90: View from Possible Substation Site on Hunters Point Shipyard to an Apparent 115 kV Cable Terminal

6.0 Uncertainty Analysis

The RDG Assessment results for the SFPUC described in the Results of Economic Screening Analysis (section 2.4) are driven by Base Case input data. The resulting conclusions are subject to uncertainty given variability in input assumptions used throughout the analysis. This uncertainty analysis allows us to test how alternate scenarios for several key input data would affect the overall results of the assessment. This chapter describes the method we used to test the sensitivity of the RDG Assessment results to particular ranges of uncertainty in the inputs. We built this testing process into the RDG screening tool so that users can easily observe the potential robustness of their results under uncertainty and subsequently improve their information for decision-making and planning.

6.1. Uncertainty Analysis for Key Inputs

We established sensitivity tests in the RDG screening analysis to examine the effect of alternative values for the following seven key input assumptions:

- generation market prices
- transmission prices
- distribution costs
- DG capital costs
- fuel costs
- capacity factor
- rates

For each input, we can select a Base, High, or Low scenario and then immediately observe the effect of this change on the cost-effectiveness results. The degree of change under each scenario can also be varied using the model.

6.1.3. Generation Market Prices

As described in the Avoided Costs section of this report, we used a Base Case forecast of electricity prices for the period from 2006 through 2025 to calculate our initial RDG economic screening. As history has shown, electricity market prices can vary dramatically from forecasted values. In order to test the effect of market prices on our Base Case results we established a 'Low' and a 'High' scenario of the forecasted values. A description of these values is provided below.

6.1.3.1. Low Scenario

In our Base Case forecast, electricity prices for the years 2006 – 2007 are given by forward electricity prices. Since these are forward contracts that a utility can buy, the forecast represents a fully hedged position. For this reason, we hold the first two years of the Low

scenarios constant with the Base Case. For years 2008 and beyond, we assume a market price equal to 80% of the Base Case.

6.1.3.2. High Scenario

We based our High generation avoided cost scenario on the SFPUC marginal retail rate of $82.89/MWh provided us by the SFPUC. This number represents the additional revenue to the SFPUC from the sale of an additional MWh of energy, inclusive of T&D value. The marginal retail rate represents an upper bound on the value of RDG since it is likely the highest amount the SFPUC could sell the energy for given the current range of market forecasts.

The Base Case, High, and Low avoided generation cost scenarios are shown in Figure 91.

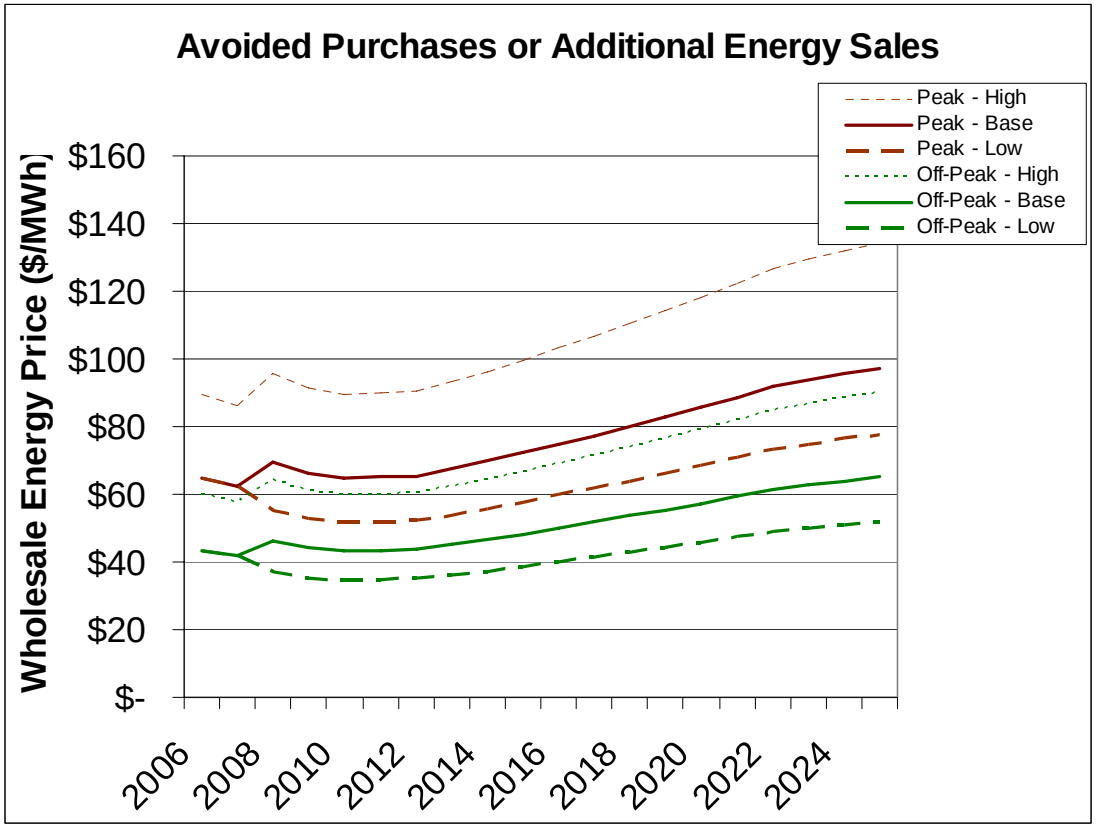

Figure 91: Comparison of Base, High, and Low scenarios for avoided generation costs

6.1.4. Transmission Prices

In the case of uncertain transmission prices, we used a Base Case value equal to current avoidable transmission costs of $5.16/MWh. Because transmission prices are unlikely to decline, we use the same value for our Low scenario. We input a High value at $15/MWh,

reflecting considerable uncertainty surrounding the possibility of "nodal" pricing under future California transmission market design.

6.1.5. Distribution Costs

While distribution costs are included in the Economic Screening model, we did not incorporate this value into the Uncertainty Analysis due to the nature of the distribution investments described in the Load and Resource section.

6.1.6. RDG Capital Costs, Fuel Costs, and Capacity Factors

RDG capital costs, fuel costs, and capacity factors are varied by plus or minus 20% of the Base Case for the High and Low scenarios respectively. These are default assumptions that can be revised by technology as more specific information is gained.

6.1.7. Rates

Rates were set to be 10% higher in the High scenario, and 20% lower in the Low scenario. This asymmetry in the sensitivity range is due to the rate structure and our base case assumptions; changing the capacity factor and other assumptions that drive our rate calculation can have a greater effect on the Low side of our Base Case assumptions than on the High side.

6.2. Results of Uncertainty Analysis

In this section, we provide the results from testing the uncertainty around the base case results from four different RDG technologies including.

- 800 kW biogas unit
- 100 kW polysulfide bromide battery
- 100 kW solar PV unit
- 750 kW wind turbine

There are numerous RDG technologies included in the screening model and each of these can be tested in a similar way.

6.2.1. 800 kW Biogas

Figure 92 shows the range of TRC test results obtained for an 800 kW biogas generator with CHP by varying each key input while holding all others at the Base Case. Although we vary only one input at a time in this example, multiple inputs can be varied simultaneously as shown below in Figure 93.

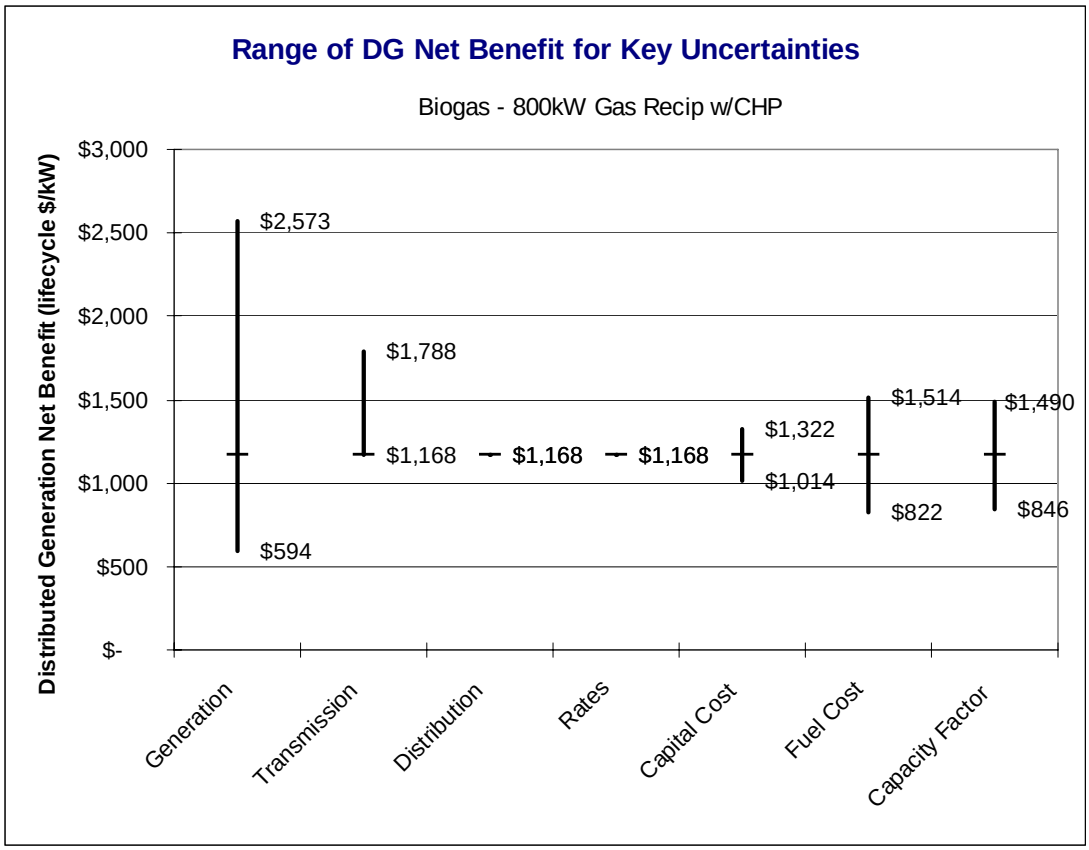

Figure 92: Net benefit range for key uncertainties from the TRC test perspective

As can be observed in Figure 92, the 800 kW biogas unit we screened is cost-effective under the TRC test in the Base Case (the central tick marks) and remains cost-effective under both our high and low scenarios of all key variables.

Figure 93 shows the results of the TRC test sensitivity analysis in the form of a 'spider diagram'. As in Figure 92, one can easily discern the effect of a move from Base to High or Low scenarios for any of the input variables. The nucleus of the spider diagram is the Base Case scenario and each 'leg of the spider' represents the effects on the overall net benefit of the RDG installation of a change in that variable while holding all other variables at the Base Case. The spider diagram also allows the reader to discern how large a change in the variable was required to effect the change in cost-effectiveness.

In the case of this 800 kW biogas generator, there is no single input variable that makes the CHP plant uneconomic from the TRC perspective.

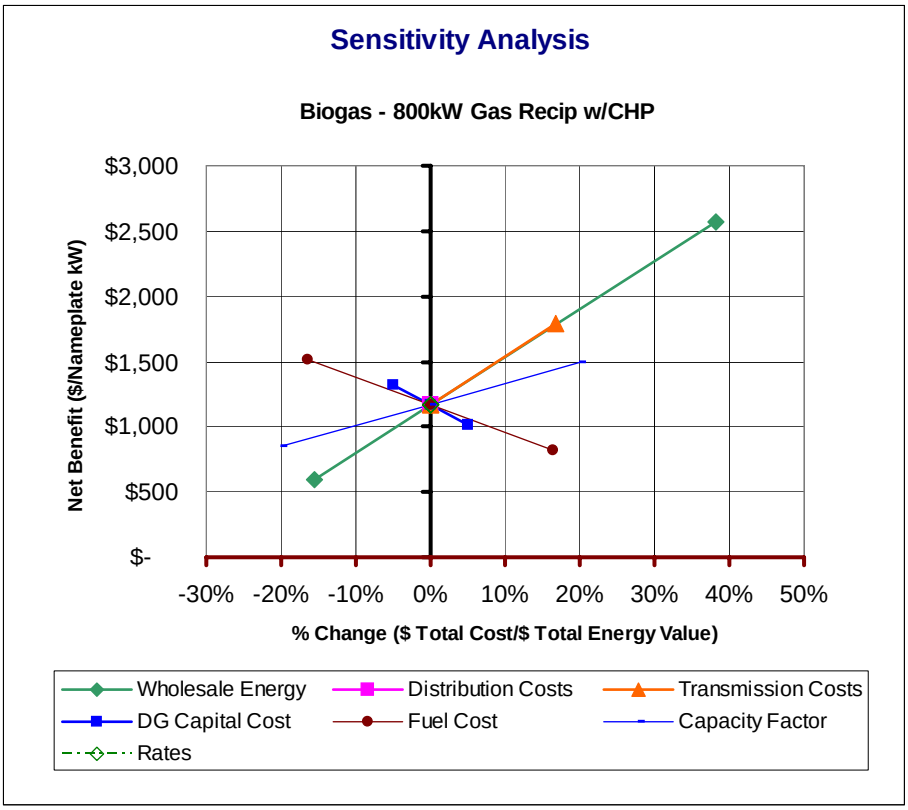

Figure 93: Sensitivity analysis for 800 kW biogas-generator with CHP from the TRC test perspective

The percentage change along the horizontal access is expressed as the change in the lifecycle value of the variable being tested, relative to the change in lifecycle value of the generation output of the unit. This generation output value is calculated as the generation unit's hours of operation multiplied by the forecasted wholesale generation price on a lifecycle basis. In the case of transmission prices, these vary in our analysis from $5.16/MWh in the Base Case to $15.00/MWh in the High case. While this is an increase in the transmission price of close to 300%, the sensitivity ratio is calculated as:

$$\% \text{ Change} = (T_H - T_B) / (G\ \text{Output}_B) = 17\%$$

where:

T = lifecycle transmission avoided cost value

G Output = lifecycle value of generation savings given the unit's output

H = High Scenario

B = Base Scenario

For the 800 kW biogas unit, wholesale energy and fuel costs under the scenario analysis change by a significant amount relative to the generation value of the unit's output. DG capital cost, in contrast, makes up a smaller percentage of overall costs, so a variation of plus or minus 20% in the DG capital cost is relatively small (<5%) when expressed as a percentage of the generation value.

6.2.2. 100 kW Polysulfide Bromide Battery

Figure 94 and Figure 95 show the sensitivity of the 100 kW polysulfide bromide battery to changes in input values. In this case, even a large increase in wholesale energy prices is not enough to yield a cost-effective result for this technology. To evaluate the economics of the flow-battery, we have used the off-peak energy price as the 'fuel-cost.' If lower priced off-peak energy were available, this would improve the economics. As is the case with many emerging technologies, the high capital costs contribute most to the poor economics. If these can be offset through research grants or research and development funding, the project could prove economical.

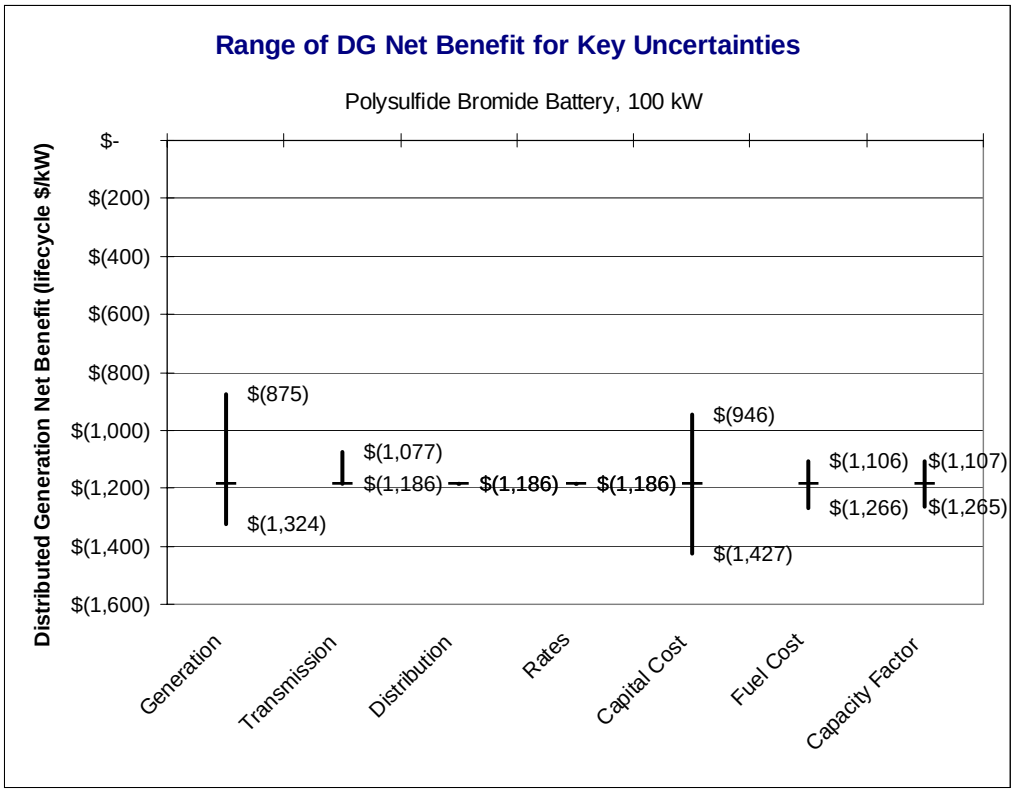

Figure 94: 100 kW polysulfide bromide battery: Net benefit range for key uncertainties from the TRC test perspective

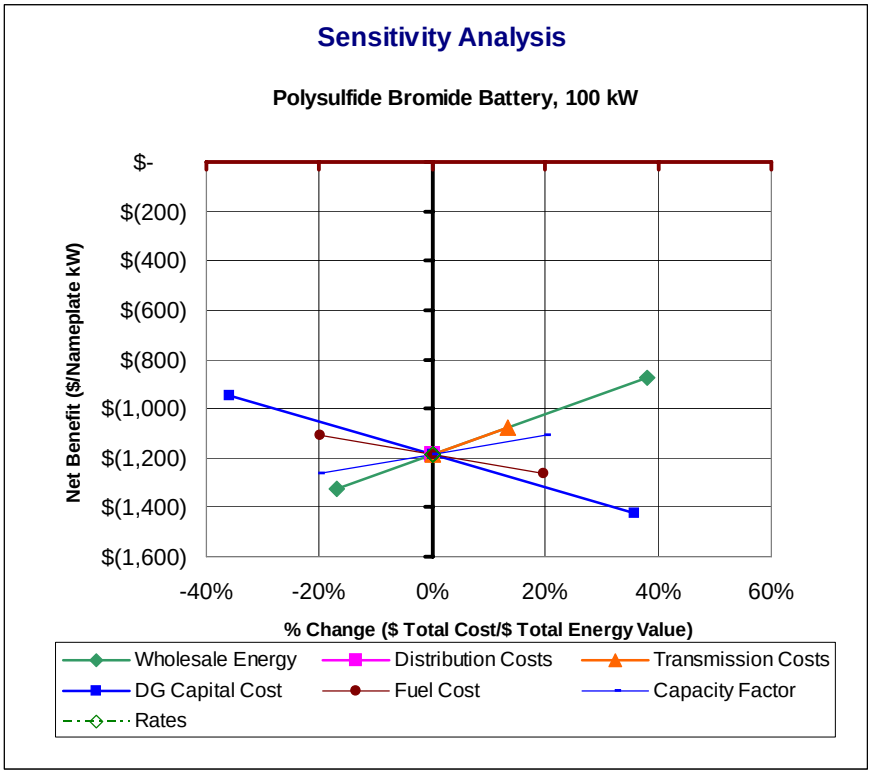

Figure 95: Sensitivity analysis for 100 kW polysulfide bromide battery (TRC perspective)

6.2.3. 100 kW Solar PV

For a 100 kW solar PV system, as with the polysulfide battery, the most important driver of results in the sensitivity analysis is capital cost, as can be observed in both Figure 96 and Figure 97. Note that the range of capital costs ranged from 50% of the Base Case to represent a high-incentive level, to 120% of the Base Case. The high capital cost per unit of output dwarfs the other variables so that a rise or fall in the capital costs has a significant effect on total costs, and therefore on the overall cost-effectiveness of the technology. Nevertheless, the technology proves not to be cost-effective even under the Low capital cost scenario.

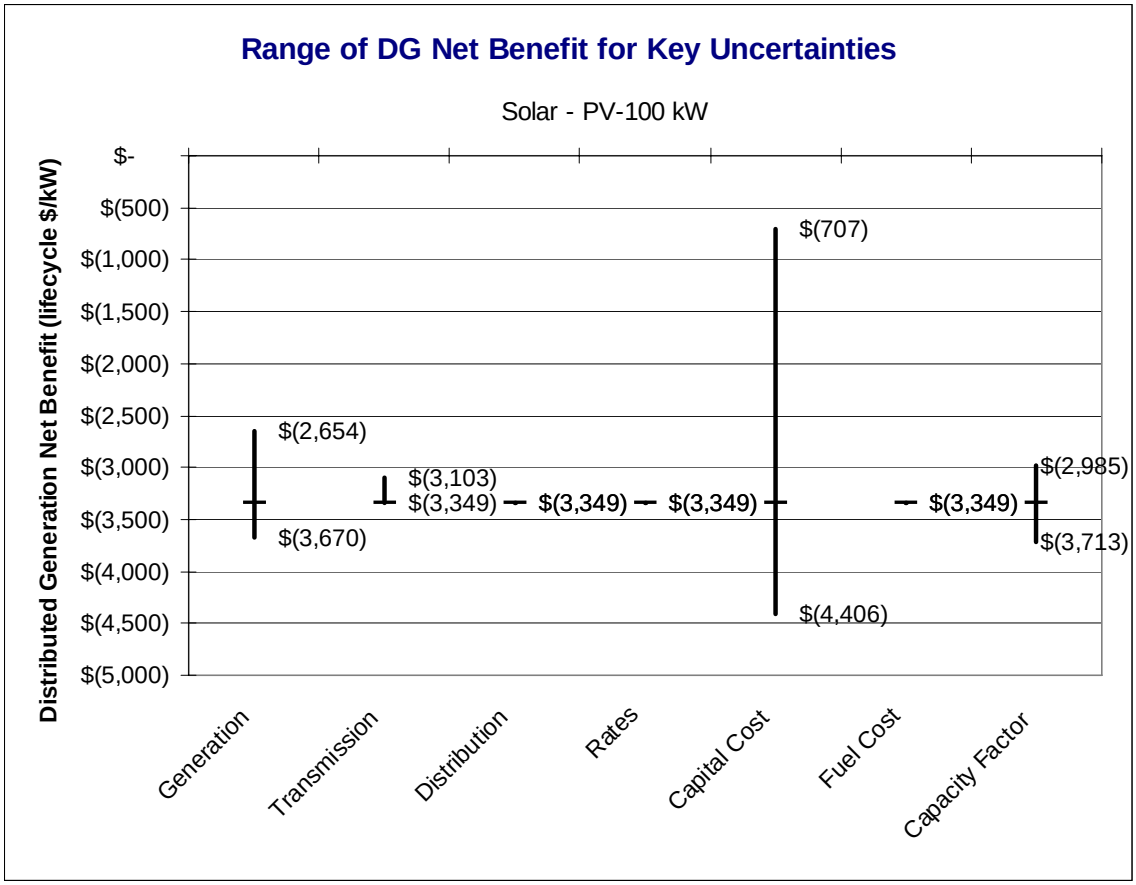

Figure 96: 100 kW solar PV: Net benefit range for key uncertainties from the TRC test perspective

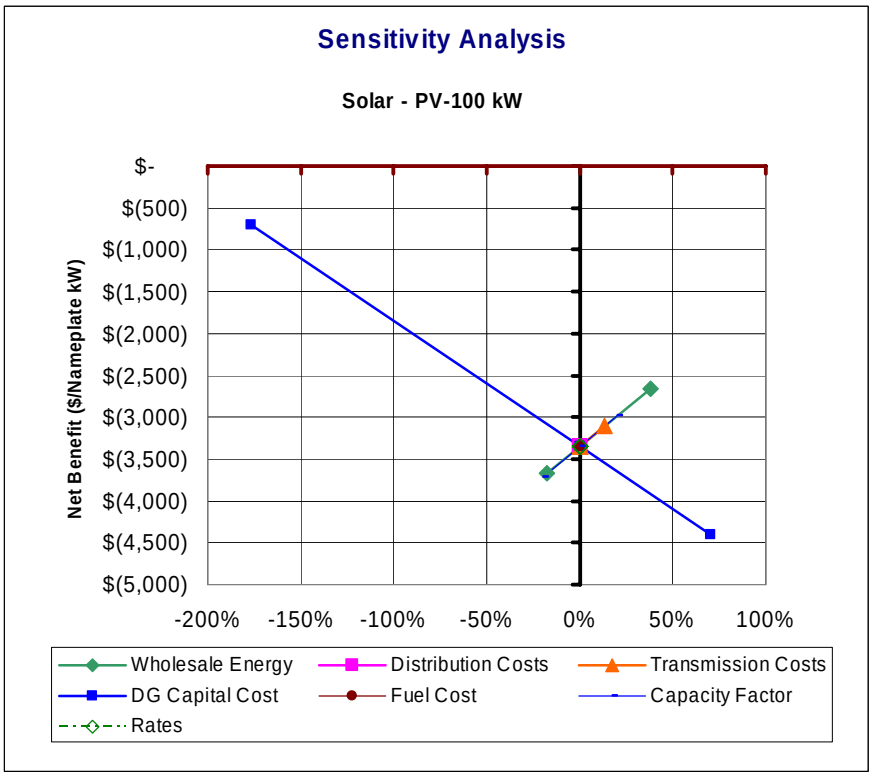

Figure 97: Sensitivity analysis for 100 kW solar PV from the TRC test perspective

6.2.4. 750 kW Wind Turbine

Figure 98 and Figure 99 show the sensitivity results for a 750 kW wind turbine. The base case assumes a 14% capacity factor for wind. The high case assumes a 35% capacity factor, which makes the wind turbine cost-effective from the TRC perspective. The capacity factor is the key sensitivity variable in the wind turbine's cost-effectiveness.

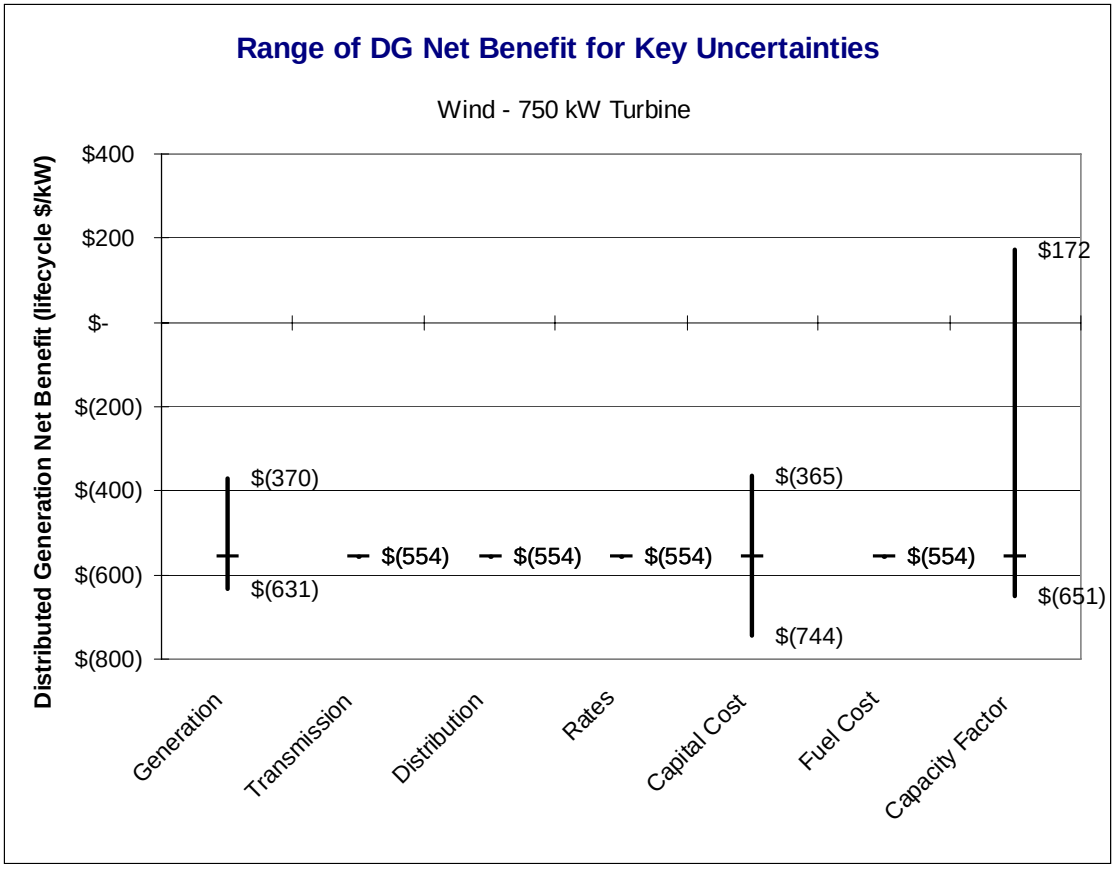

Figure 98: 750 kW wind turbine: Net benefit range for key uncertainties from the TRC test perspective

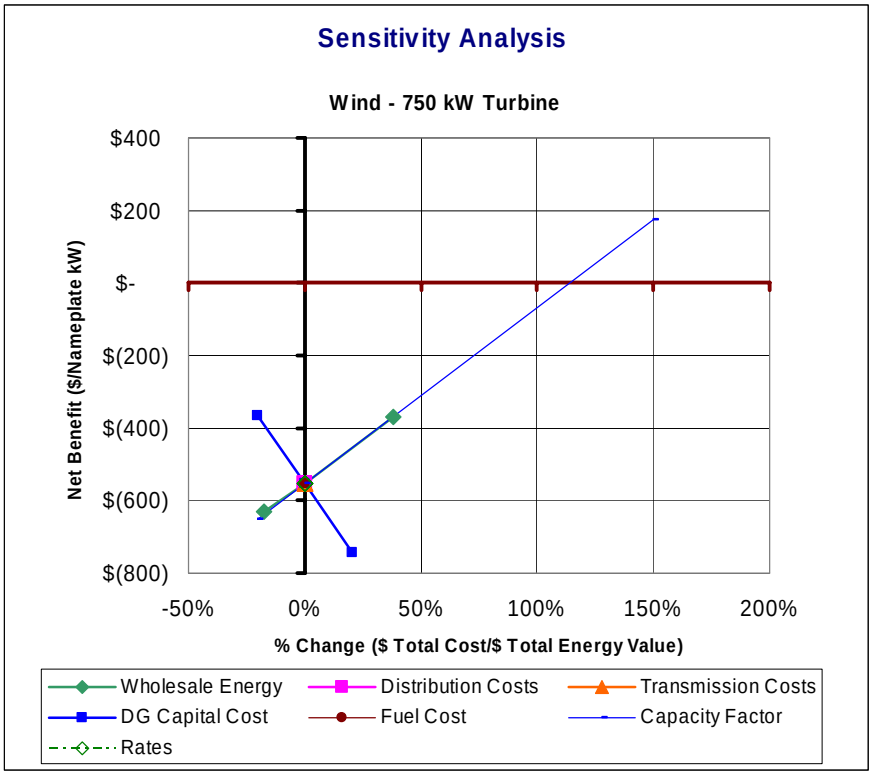

Figure 99: Sensitivity analysis for a 750 kW wind turbine from the TRC test perspective

6.3. Uncertainty Analysis Conclusions

The uncertainty results shown in this chapter are a small sample of the potential range of actual values for the input variables used in the RDG Assessment. However, these results show how each type of technology has one or several input assumptions that have the greatest affect on the cost-effectiveness results. By examining these sensitivity results, decision-makers can decide to pursue an RDG project with a more complete understanding of the risks associated with the investment.

Appendix A: Cost and Performance of Renewable DG Technologies

Renewable energy technologies are best categorized by their energy source or fuel type: solar, wind, hydro, geothermal, or biomass. For each fuel, various energy conversion technologies exhibit distinct strengths and weaknesses, and not all are well-suited to DG applications. Solar PV and microturbines, for example, are particularly suited to addressing localized distribution requirements, while wind and geothermal require larger, site-specific installations.

Below we briefly describe the performance and cost characteristics of each technology and present a table with key performance data used in our economic analysis.

A-1 Solar

Solar technologies fall into two categories: photovoltaic (PV) and thermal. The former employs an array of semiconducting wafers or film that directly generate DC current from incident sunlight. Owing to their modular nature, these arrays are highly scalable. While their output is dependent upon intermittent sunlight, it often coincides with summer peak loads. Real estate for larger installations can be a significant expense, which has prompted the development of unused industrial and commercial rooftops.

Solar-thermal or concentrated solar power (CSP) technologies employ heat to generate power. They consist of a solar concentrator, typically an array of mirrors, and a power converter (such as a turbine), which ultimately drives a generator to produce electricity. Most common among these is the "solar trough" configuration, in which a parabolically shaped trough of reflective material focuses light on a piped fluid. Though the energy source is intermittent, the heat sink fluid can be stored, allowing these technologies to offer high-value dispatchable power. But given their dependence on economies of scale, these technologies are best suited to multi-megawatt installations[19].

Solar dish engines, however, offer greater modularity in a solar-thermal technology. They use an all-in-one power conversion system that typically uses a Sterling engine-generator to convert heat to electricity. Individual units range from 9-25 kW. Like all solar-thermal technologies, while presently expensive, they employ relatively conventional components that show promise of improving economic competitiveness in the near term.

A-2 Wind

Wind energy technologies convert the kinetic energy of moving air into electricity via an airfoil that drives an electric generator. Despite their apparent similarities, wind turbines vary significantly in their size and kind of electrical output. Since the R&D boom of the early 1980's, the upwind, horizontal-axis design has come to predominate. Rotor diameters range from two arm spans (1 kW) to nearly four hundred feet (5 MW), and towers vary similarly in height. However, the smaller wind turbines are significantly less

[19] http://www.energylan.sandia.gov/sunlab/overview.htm#tower

efficient, and wind economics greatly benefit from installations greater than 20 MW. In today's market, the large wind farms that capture economies of scale, combined with a Federal Production Tax Credit of $1.8 cents/kWh and other tax incentives, are cost-effective yet site-specific.

Wind turbines typically produce AC power via induction or synchronous generators. Induction generators are simpler, but require reactive power from the grid, while synchronous generators require advanced power conversion electronics, but can generate more energy for a given wind regime. Aesthetic appraisals of wind turbines range from elegant to ugly, and some wind turbines create low-frequency noise, which may affect siting considerations. Avian mortality has been another concern for wind power, especially in the Altamont region, though mortality rates have fallen sharply with the preponderance of larger, slower-spinning turbines mounted on tubular instead of lattice towers.

A-3 Hydro

Hydroelectric dams, which convert the potential energy of stored water into electricity via a turbine, produce most of the renewable electricity in California today. Almost all suitable dam sites have already been developed in California, and permitting is becoming ever-more expensive and time consuming.
In contrast, "micro" hydro technologies do not require dams and operate on a "run-of-the-river" basis. As such, these hydro technologies are not dispatchable technologies. The option we consider here converts the kinetic energy of extant municipal water flows into electricity.

A-4 Geothermal

Heat and/or pressure extracted from subsurface water and permeable rock can be converted to electricity via steam powered turbine-generators. Wells typically range from one to several miles beneath the Earth's surface. While this form of renewable energy generation can offer affordable and dispatchable power in the 20-80 MW size, it is highly site-specific, and is thus not well suited to distributed generation.

A-5 Biomass

Organic residues from landfills, agricultural waste, timber scraps, etc. can be converted thermochemically or biochemically into electricity through a variety of energy conversion pathways. Most commonly, a biomass supply is purified into a fuel and then burned in a turbine or engine that would typically consume fossil fuels. The best biomass solution depends upon the fuels and technologies at hand. We have included biodiesel and biogas technologies in the Screening Model.

A-6 Biodiesel

Vegetable oils and animal fats can be chemically converted into biodiesel, which will power compression-ignition (diesel) engines with little or no modifications. In addition to emitting fewer particulates, unburned hydrocarbons, carbon monoxide, and oxides of sulfur than conventional diesel, biodiesel is renewable. It also offers superior lubricity with equal BTU content. Emissions of nitrogen oxides can be slightly more or less, depending on the engine's duty cycle. Biodiesel is most commonly combined with petroleum-based diesel in a 20% biodiesel mixture (known as B20); higher percentage blends can impact elastomer- and rubber-based fuel system components (though these are being phased out as new diesel standards take effect). Biodiesel is currently slightly more expensive than its petroleum counterpart, and is available nationwide. Biodiesel meets the clean diesel standards established by the California Air Resources Board.

A-7 Biogas

Solid biomass such as timber waste can be directly burned or co-fired with coal to power a steam turbine-generator, reducing net carbon emissions. Municipal solid waste (MSW) and other forms of biomass can also be converted into fuel via the following methods:

- Gasification – the substance is heated in the absence of oxygen to produce a mixture of hydrogen, carbon monoxide, and methane.
- Anaerobic digestion – bacteria consume the biomass and produce methane. This occurs naturally in landfills.
- Pyrolysis – a chemical/thermal process that produces an oil similar to diesel, though with less energy content.

Landfill gases, principally composed of equal parts methane and carbon dioxide, can also be collected, filtered, and converted to electricity. Whichever pathway is selected, the resultant fuel can then be burned in a reciprocating engine, microturbine, or fuel cell.

A-8 Biomass Fuel Prices

Short transportation distances from the biomass supply to the power generation point are critical to the economic viability of producing electricity from biofuels. Feedstock price, which can also vary widely, has the greatest influence on the price of biodiesel—production costs alone span a six-fold range. Average U.S. wholesale biodiesel prices in early 2004 are $1.18/gal ($8.58/mmBTU) for B20 and $2.12/gal ($15.41/mmBTU) for B100. In the case of MSW gasification, consistent data on the feedstock price is still scarce. The economics of landfill gas-to-energy has been more consistently studied, though the price of the feedstock depends on the difficulty of harvesting the resource, and the quality of the recovered gas. The EPA observes that prices typically range from $6-13/mmBTU for landfill methane. We have used the average value as the default in our Screening Tool.

A-9 Fuel Cells

These solid-state devices convert chemical energy directly into electricity very efficiently and with negligible emissions. While the technology is not new, it is just beginning to be commercialized. Inside each fuel cell, a catalyst is used to create electricity from a fuel such as hydrogen. The fuel cell end products include water, heat, and electricity. Hydrogen can be obtained from methane via reformation, a thermo-chemical process which can take place inside some designs, and in an auxiliary unit with others. Fuel cells are categorized by their electrolyte and their operating temperature. The four major types are:

Phosphoric Acid (PAFC) – these have been commercially available since the early 1990's. They operate around 200°C. PAFCs require an external reformer.

Proton Exchange Membrane (PEMFC) – these low-temperature (65-85°C) fuel cells have received major R&D from the automotive industry. Small 1-5kW models for home are available in Japan and Germany, and will be available in the U.S., along with larger sizes, in the next few years. PEMFCs offer high power densities and can vary their load quickly to meet fluctuating demand. However, they require pure, externally reformed hydrogen.

Molten Carbonate (MCFC) - due to its operating temperature of nearly 700°C, MCFCs hold promise for CHP and DG applications, as they can internally reform methane into hydrogen. They have just begun to be commercially available.

Solid Oxide (SOFC) – generally considered to be less mature than MCFCs or PAFCs, SOFCs offer high reliability and efficiency, in addition to high operating temperatures (750-1,000°C), which make internal reforming possible. 2005 should see the first commercially available SOFCs.

A-10 Energy Storage Technologies

The following technology summaries are from a draft report prepared for the CEC's "Project 4.3: Energy Storage for Renewable Generation," which is funded under the CEC's *Renewable Energy Research Program To Make Renewables Part of California's Affordable and Diverse Public Power System,* CONTRACT # 500-01-042.

Vanadium Redox Systems Batteries

Vanadium redox batteries (VRB) store energy in electrolytes based on ionic forms of vanadium. At the positive electrode, V5+ is converted to V4+ during discharge through the acceptance of an electron. At the negative electrode, V2+ is converted to V3+ through the release of an electron. The reactive species are in solution both before and after the reaction.

There have been several prominent VRB projects at the utility scale. In 2003, PacifiCorp, a utility in the Northwestern U.S., installed a VRB facility on a distribution feeder at Moab,

Utah. This facility, constructed by VRB Power Systems Inc., is designed for peak shaving and voltage support functions to avoid upgrading the feeder. The upgrade was considered undesirable in the environmentally sensitive area.

In addition, VRB projects have been installed in conjunction with several wind projects. In 2003, a 200 kW vanadium redox flow battery was installed on King Island, Australia, to provide stabilization and time shifting services in connection with a 2450 kW wind installation. The small island of the coast of the Tasmania has a population of about 1,500 and a peak power load of about 3 MW. In this situation, in which a small grid gets significant percentage of its power from wind energy, energy storage has clear value.

A similar wind installation, at a larger scale, is planned in Japan. In 2003, J-Power, a Japanese generation utility, announced that it would install a new VRB system at its Tomamae Wind Villa wind farm at Tomamae, Hokkaido. The J-Power installation will consist of a VRB system sized to provide 4 MW for 1.5 hours, or 6 MW for 20 minutes, with an inverter capability of 6 MVA. The main function served by the installation will be power output stabilization and time shifting.

Other Flow Battery Technologies

Several other flow battery technologies exist, of which two should be mentioned here. Polysulfide-bromide (PSB) batteries are flow batteries based on a reaction between sodium bromide and sodium polysulfide. PSB batteries were under development by Innogy, a UK subsidiary of RWE, under the brand name Regenesys. Two demonstration sites were planned, one at the Little Barford Power Station in the UK, and the other near Columbus, Mississippi. These plans were halted when RWE withdrew the Regenesys technology from the market in late 2003. In 2004, VRB Power Systems, Inc. licensed the technology from RWE, to continue development efforts with possible reintroduction in several years.

Cerium-zinc flow batteries have been proposed by a company called Plurion Systems, Ltd. According to the company's claims, a cerium-zinc battery would produce a higher voltage than other flow batteries, making it easier to produce a system with workable voltage. As of this writing, Plurion has not yet released a product, and it appears that this technology is still in the early stages of development.

Sodium-Sulfur Batteries

Sodium-sulfur batteries are based on a high-temperature electrochemical reaction between sodium and sulfur, separated by a beta alumina ceramic electrolyte. While originally developed for electric vehicle applications, they were adapted for the utility market by the Tokyo Electric Power Company (TEPCO) and NGK Insulators, Ltd., both based in Japan. By the late 1990s, NGK and TEPCO had deployed a series of large-scale demonstration systems, including two 6 MW, 48 MWh installations at TEPCO substations. In 2002, TEPCO and NGK announced full commercialization of their sodium-sulfur battery line under the trade name NAS, for power quality and load shifting applications. Also in 2002, the first NAS battery was installed in the U.S. at an American Electric Power (AEP) laboratory at Gahanna, Ohio.

Sodium-sulfur batteries have excellent cycle life and are relatively mature products, with over 55 installations worldwide. As such, they are an excellent candidate for peak shaving and load leveling applications at the distribution level in the near future. The main obstacle to their deployment is the cost; a drop in price is likely to make them very attractive for these applications.

A-11 Performance characteristics

Below we present a matrix summarizing the performance, cost, and other important attributes of renewable technologies. Some are particularly suited to addressing localized distribution requirements (e.g. solar PV, microturbines), while others require larger, site-specific installations (e.g. wind, geothermal). Hybridizing these technologies may provide additional benefits. Combining PV with fuel cells, for example, may offer a way to address intermittency while maintaining a low emissions footprint.

	Solar PV	Solar Thermal (CSP)	Wind	Hydro	Low-temp fuel cell	High-temp fuel cell	Micro-turbine	Diesel Recip Engine	Gas-fired CCGT	Energy Storage (Batteries)
Size (MW)	0.001-0.10	.025 - 80	0.05-3.0		0.001-0.25	0.25-3	0.025-0.30	0.05-10	50-250	0.01 - 10
Fuel	none	none	none	none	biogas	biogas	biogas	biodiesel	gas	Primary (off-peak) electricity source
Installed Cost ($/kW)	6,675-8,650	5,700	1,000-6,000	N/a	5,346-12,507	5,731-8,338	2,200-2,600	250-500	350-450	1500 - 3000
Heat rate (Btu/kWh)	N/a	N/a	N/a	N/a	9000-10,000	7000-8000	11,000-14,000	8000-11,000	7000	60-80% efficiency
O&M ($/MWh)	5	10 - 23.0	10	N/a	15	10	10	20	5	2-5
Cogeneration (Btu/kWh)	0		0	0	4000-5000	1500-3000	5000-8000	3000-5000	0	0
NOx emissions (lb /MWh)	0	0	0	0	0.02	0.01	1	15-20	0.06	0 direct emissions
CO2 emissions (tC/MWh)	0	0	0	0	0.13-0.15	0.10-0.12	0.16-0.20	0.12-0.16	0.1	0 direct emissions
Construction Time	days	months	weeks	years	days	weeks	days	days	months	Days- months
Average Annual Capacity Factor (%)	18%	24%	36%	42%	96%	96%	96%	95%	99%	10-25%
Start-up time (sec)	intermittent	intermittent	intermittent	"Fast"	“Fast”	“Slow”	120	10	600-1800	“Fast”

Dispatchable?	No, but coincident w/ peak loads	No, but coincident w/ peak loads	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Load following?	Yes, w/ storage	Yes, w/ storage	No	Yes	Yes	Limited	Yes	Yes	Yes	Yes
Noise problem?	no	no	Possible	no	Unlikely	Unlikely	Possible	Likely	Unlikely	No