FINAL REPORT

RENEWABLE ENERGY ASSESSMENT

PREPARED FOR

San Francisco Water Power Sewer

Services of the San Francisco Public Utilities Commission

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BLACK & VEATCH
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LIST OF ABBREVIATIONS

ac	Alternating Current
ARRA	American Recovery and Reinvestment Act
BLM	Bureau of Land Management
BOP	Balance of plant
C	Celsius
CAISO	California Independent System Operator
CARB	California Air Resource Board
CF	Capacity Factor
CREB	Clean Renewable Energy Bonds
CRR	Congestion Revenue Rights
CSI	California Solar Initiative
dc	Direct current
DOE	Department of Energy
EBIT	Earnings Before Interest and Taxes
EGS	Enhanced Geothermal System
EIA	Energy Information Agency
FIT	Feed In Tariff
FMV	Fair Market Value
FTR	Firm Transmission Rights
GHI	Global Horizontal Irradiance
GO	General Obligation
IOU	Investor Owned Utility
IPP	Independent Power Producer
IRS	Internal Revenue Service
ITC	Investment Tax Credit
kW, kWh, kWp	Kilowatt, Kilowatt Hour, Kilowatt Peak
LADWP	Los Angeles Department of Water and Power
LCOE	Levelized Cost of Electricity
m/s	Meters per second
m^2	Square Meter
MACRS	Modified Accelerated Cost Recovery System
MW, MWh, MWp	Megawatt, Megawatt Hour, Megawatt Peak
NMTC	New Market Tax Credits
O&M	Operations and Maintenance
PACE	Property Assessed Clean Energy
PG&E	Pacific Gas & Electric
PIER	Public Interest Energy Research
PIRP	Participating Intermittent Resource Program
PPA	Power Purchase Agreement
psf	pounds per square foot
PTC	Production Tax Credit

PURPA	Public Utilities Regulatory Policy Act of 1978
PV	Photovoltaic
QECB	Qualified Energy Conservation Bonds
QZAB	Qualified Zone Academy Bonds
RAM	Renewable Auction Mechanism
REAP	Rural Energy for America
REC	Renewable Energy Credits
REIT	Real Estate Investment Trust
REPI	Renewable Energy Production Incentives
RETI	Renewable Energy Transmission Initiative
RPS	Renewable Portfolio Standard
SAT	Single Axis Tracking
SCADA	Supervisory Control and Data Acquisition
SGIP	Self-Generation Incentive Program
sq. ft.	Square Foot
SSE	Surface meteorology and Solar Energy
TEPPC	Transmission Expansion Planning Policy Committee
TMY	Typical Mean Year
V, kV	Volt, Kilovolt
W, Wh, Wp	Watt, Watt Hour, Watt Peak
WECC	Western Electricity Coordinating Council
WREZ	Western Renewable Energy Zones
WWTP	Wastewater Treatment Plant

Legal Notice

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1.0 Executive Summary

Black & Veatch is pleased to provide this report to assist the San Francisco Public Utilities Commission (SFPUC) in planning to achieve long-term renewable energy goals.

1.1 BACKGROUND AND OBJECTIVES

The SFPUC is considering a range of potential options to meet future renewable energy targets and load growth needs. SFPUC staff and contractors have previously identified several promising technologies and development locations. In this report, Black & Veatch builds upon the previous analysis by developing updated cost and performance estimates for deployment of representative solar photovoltaic (PV), wind, and geothermal technologies in potentially developable locations. The objective of this report is to identify and characterize the cost and performance of facilities that could be used to deliver power to the SFPUC in the future. While an effort was made to select project sizes and locations to represent a wide range of options available to the SFPUC, the list explored in this study should not be considered an exhaustive review of all available options.

1.2 SCOPE AND STUDY AREA

Wind, solar PV, and geothermal projects were evaluated within San Francisco ("in-city"), on SFPUC controlled lands, and throughout the state. Analysis of in-city and projects on SFPUC controlled lands was performed using local data for project sizing and resource potential. Statewide project analysis is based upon work recently conducted by Black & Veatch as part of the California Renewable Energy Transmission Initiative[1] (RETI) and Western Renewable Energy Zones[2] (WREZ) projects. Previously performed resource assessments for wind, solar, and geothermal projects were updated to identify areas throughout the state where economically feasible projects could be developed for the SFPUC. Transmission constraints were also considered when selecting project sizes and locations. A review of available incentives and ownership structures was performed, and the levelized cost of energy was modeled for each project. Supply curves were developed to represent the cost and performance of selected renewable energy options available to the SFPUC throughout the state.

1.3 RESOURCE ASSESSMENT AND SUPPLY CURVES

Wind, solar PV, and geothermal projects in California were considered for this analysis. While other renewable energy options may be available to the SFPUC, such as biogas and ocean wave generation, these opportunities are either too limited or too expensive to represent a major portion of future requirements at this time.

[1] The RETI reports are available online: http://www.energy.ca.gov/reti/documents/index.html
[2] The WREZ report is available online: http://www.nrel.gov/docs/fy10osti/46877.pdf

1.3.1 Solar Photovoltaic Assessment and Results

This assessment consisted of cost and performance analysis for solar PV options on rooftops in San Francisco (assuming new building construction or no major building upgrades at existing sites), at SFPUC owned reservoirs, ground-mount projects on SFPUC land, and large ground-mount projects elsewhere in the state. Data from past studies performed for the SFPUC by other consultants were reviewed and updated for six SFPUC reservoir rooftops and two other SFPUC owned sites (Sunol and Tesla). Cost and performance of rooftop facilities within the city was developed by Black & Veatch for four rooftop sizes and three neighborhoods. Estimated costs for in-city systems were based on typical industry costs adjusted for higher development costs in San Francisco. These costs were compared to current market pricing for San Francisco installations based on California Solar Initiative (CSI) data. For San Francisco, this data indicates that for many rooftop projects, the capital cost averaged roughly $6/Wdc, equivalent to about $7.7/Wac.[3] While projects that will be installed on SFPUC reservoirs will be larger than the systems reported by the CSI, San Francisco specific cost factors remain relevant for SFPUC developed projects per input from SFPUC staff. Finally, costs were developed for importing solar PV power from a few representative large projects located outside of San Francisco. These were located near large electric substations: Midway, Windhub, and Imperial Valley. Project data developed for the RETI and WREZ projects were used for estimating cost and performance. These projects have lower capital costs than the in-city projects, but will incur transmission costs to deliver the power to San Francisco.

The plant size, performance, cost factors, and estimated levelized cost of electricity (LCOE) using a power purchase agreement (PPA) with transfer ownership structure for all solar PV projects can be seen below. The PPA with transfer structure involves executing a PPA with a private company with eventual transfer of ownership of the project to SFPUC. While a range of other ownership options were explored, the PPA with transfer finance structure provided the lowest cost without adding considerable complexity to the agreement.

[3] While industry data is often reported in Wdc, for consistency with the other resources covered in this report, all solar cost and performance data is shown on an AC basis.

Table 1-1 Photovoltaic Costs and Performance Comparison

LOCATION	PLANT CAPACITY (KWAC)	AC CAP. FACTOR (PERCENT)	CAPITAL COST ($/KWAC)	O&M COST ($/KW-YR)	LCOE ($/MWh)
SAN FRANCISCO ROOFTOPS AND SFPUC RESERVOIRS					
Hunters Point	2.5	20.3	7,365	45	222.67
Hunters Point	5	20.3	7,365	45	222.67
Marina Middle School	50	21.1	7,245	27	198.39
Thurgood Marshall	200	22.3	6,165	27	162.58
College Hill Reservoir	895	20.8	6,000	27	170.27
Summit Reservoir	664	19.7	6,075	27	182.15
Stanford Hts. Reservoir	704	19.6	6,060	27	181.98
Sutro Reservoir	2,010	19.7	5,550	27	168.09
University Reservoir	2,883	20.8	5,385	27	154.39
Pulgas Reservoir	2,650	21.5	5,385	27	149.64
GROUND MOUNT AT UP-COUNTRY LOCATIONS					
Tesla	1,600	24.8	3,420	22	85.40
Sunol	19,200	23.9	2,930	22	80.48
OTHER IN-STATE GROUND MOUNT LOCATIONS					
Midway Fixed Tilt	20,000	26.7	3,289	29	80.49
Windhub Fixed Tilt	20,000	29.2	3,289	29	73.60
Imperial Fixed Tilt	20,000	28.2	3,289	29	76.21
Midway Tracking	20,000	31.6	3,536	32	73.50
Windhub Tracking	20,000	35.9	3,536	32	64.70
Imperial Tracking	20,000	33.4	3,536	32	69.54

Notes:

- **For non-rooftop projects, this does not reflect delivered prices at load. These numbers are not necessarily what the SFPUC will pay due to market factors and SFPUC development considerations.**
- **Capital costs cover all construction and development requirements. They do not reflect any incentives or tax credits; these are taken into account in the LCOE calculation.**

The results of the solar PV analysis shows that the up-country SFPUC locations and large statewide ground mounted facilities have LCOEs roughly half those of rooftop development locations in San Francisco or any of the SFPUC water reservoirs. This is due to the larger size and better solar resource for the projects sited away from San Francisco. The costs for the projects located outside of San Francisco reflect costs to interconnect the power into the California Independent System Operator (CAISO). After any charges from the CAISO and PG&E to bring the power into San Francisco are included, the LCOEs for the large ground mount projects remain much lower than for in-city projects.

1.3.2 Wind Assessment and Results

Black & Veatch performed cost, technology, and production assessments for wind projects at SFPUC owned facilities and developed comparisons to projects built in other areas of California.

Cost and performance estimates were made for wind sited at two up-country locations (Sunol and Tesla), as well as for one in-city location (Oceanside WWTP). The team also identified the cost for importing power from a few representative large wind projects located at good wind resources in California within the CAISO. Project data developed for the RETI and WREZ projects was used in this analysis. The plant size, performance, cost factors, and estimated LCOE using a PPA with transfer finance structure can be seen below.

Table 1-2 Wind Costs and Performance Comparison

LOCATION	PLANT CAPACITY (KWAC)	CAPACITY FACTOR (PERCENT)	CAPITAL COST ($/KWAC)	FIXED O&M COST ($/KW-YR)	VARIABLE O&M ($/MWh)	LCOE ($/MWh)
Oceanside	2,000	29	2,738	60	0	82.01
Sunol	30,000	15	2,577	35	0	129.85
Tesla	6,000	20	2,820	35	0	104.33
Montezuma Hills	100,000	31	2,043	35	2.66	56.13
Altamont Pass	20,000	34	2,349	35	2.68	56.63
Walnut Grove	170,000	34	2,244	35	2.70	54.89
Leona Valley	100,000	37	2,649	35	2.62	56.85
Newberry Springs	100,000	34	2,332	35	2.68	56.34

Notes:

- **Reflects cost of new generation using typical industry development assumptions at sites with few barriers to construction.**
- **LCOEs are at the site and do not reflect delivered prices at load. These numbers are not necessarily what the SFPUC will pay due to market factors and SFPUC development costs.**
- **Capital costs cover all construction and development requirements. They do not reflect any incentives or tax credits; these are taken into account in the LCOE calculation.**

The results of the wind analysis shows that the in-city and up-country locations on SFPUC land are located in much poorer wind resources areas, leading to considerably higher LCOEs. In addition, these locations have less land for development when compared to the other locations analyzed throughout the state, which could support a large facility and take advantage of economies of scale. Finally, the operating cost of the Oceanside facility has been raised to try to reflect the unique operating conditions for an urban single-turbine wind facility because the ability to permit and obtain local acceptance of a wind project in this location would be much more challenging than the other project sites.

1.3.3 Geothermal Assessment and Results

Cost, technology, and production assessments were developed for several California geothermal projects that could import power to the SFPUC. The resource assessment performed for the SFPUC by GeothermEx in 2010 was used along with RETI and WREZ resource and cost comparisons for the analysis. This study updates costs for each of the areas previously identified and also identifies the three lowest cost locations based on capital costs and transmission constraints. The plant size, performance, cost factors, and estimated LCOE using a PPA with transfer finance structure can be seen below.

Table 1-3 Geothermal Costs and Performance Comparison

LOCATION	NET PLANT CAPACITY (KWAC)	CAPACITY FACTOR (PERCENT)	CAPITAL COST ($/KWAC)	VARIABLE O&M ($/MWh)	LCOE ($/MWh)
Brawley - Binary	50,000	80	4,963	30	61.91
Geysers - Flash	50,000	90	4,467	27	53.37
Long Valley – Binary	40,000	80	4,283	34	63.81

Notes:

- **LCOEs are at the busbar and do not reflect delivered prices at load. These numbers are not necessarily what the SFPUC will pay due to market factors.**
- **Capital costs cover all construction and development requirements. They do not reflect any incentives or tax credits; these are taken into account in the LCOE calculation.**
- **The geothermal resource at these locations is well understood; it is assumed that predictions of the heat available will be realized. Less understood resources will have higher costs.**

All of the geothermal projects analyzed are promising and could provide low cost power to the SFPUC. However, the challenge with any new geothermal project is assurance that the geothermal heat resource can produce at the projected output levels and cost projections over the entire life of the project, as well as the long lead times for development.

Based on Black & Veatch and SFPUC's experience with recent market pricing for geothermal projects, the costs estimated in this report are significantly below the prices being offered in the market. While the prices shown above may reflect the development cost for the best known resource areas, a number of factors, including development risk, higher investor return expectations, project costs, uncertainty of pricing given the thin market for available projects, and resource availability would likely drive prices up beyond the costs estimated in this report. Furthermore, as a dependable baseload resource, geothermal developers may feel they offer a more valuable product than variable wind and solar resources. Due to this uncertainty, it was decided that the focus of the economic comparisons in the supply curve later in this report should be on resources (wind and solar) that have a greater chance of development at costs consistent with on actual transaction prices. Nevertheless, SFPUC should still consider geothermal as a potentially competitive resource option.

1.3.4 Incentives and Financial Structures

The economics of renewable energy are strongly tied to available incentives and the financing and ownership structure of the project. Black & Veatch identified the main financial incentives available to the SFPUC and private developers, including federal, state, and local options. In the base case financial model developed for this study, a 30 percent investment tax credit (ITC) and accelerated depreciation is assumed in all cases where ownership is by a taxable entity. While this credit expired at the end of 2013 for wind and geothermal projects, projects that are currently under construction would still be able to capture these credits.

The ownership structure of a project can have a material impact on the electricity cost paid by the SFPUC due to eligibility for incentives, cost of financing, and tax treatment. The major structures considered in this study are SFPUC ownership, PPA with and without transfer, prepay PPA (also with and without transfer), and real estate investment trust (REIT). The financial model provided with this report demonstrates the differences between some of the major structures.

To demonstrate the differences between the best resource and ownership options, the LCOEs in $/MWh for the lowest LCOE solar PV reservoir (Pulgas), single-axis tracking (SAT) ground mount solar PV (Windhub SAT), wind (Walnut Grove), and geothermal (Geysers) sites modeled as part of this analysis for each of the five ownership options[4] are compared in the figure below.

[4] Given the barriers to the use of REITs and the uncertainty regarding their viability in the current market, this financial structure is not recommended as an option for near-term project financing.

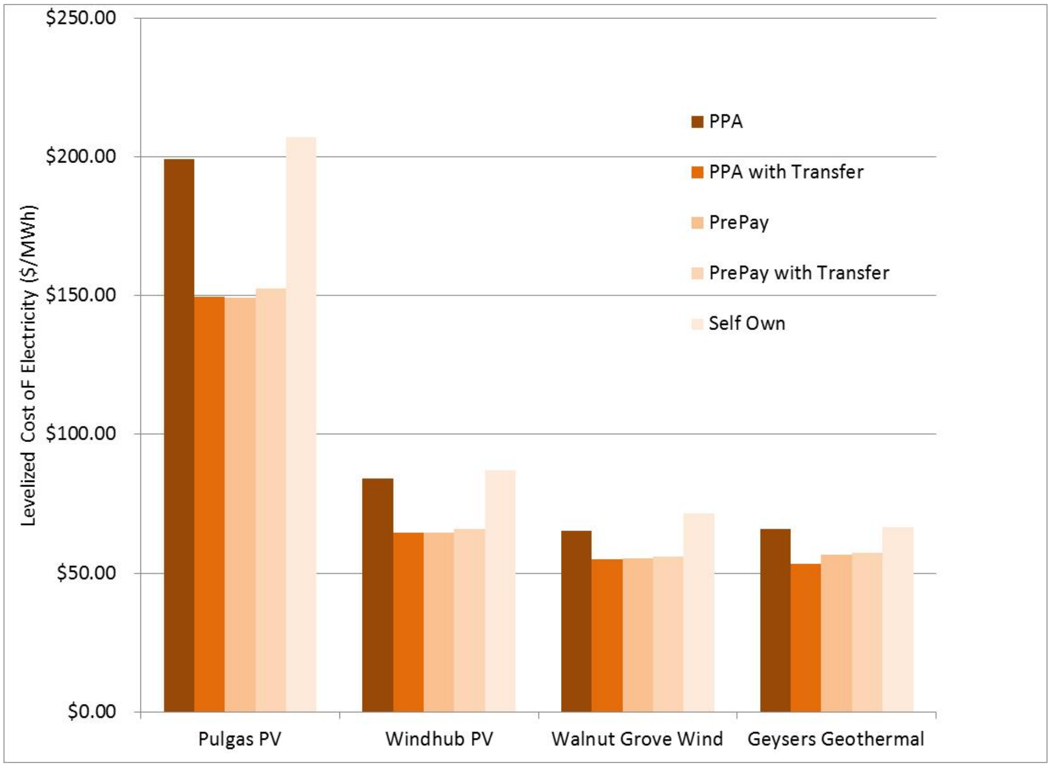

Figure 1-1 Ownership Option Comparison, Best Resources

1.3.5 Supply Curve

A supply curve for wind and solar projects identified during the resource assessment was developed to compare the cost to the SFPUC of each resource. The supply curve reflects the cost of generation versus the energy generation potential. The total amount of large scale wind energy was normalized to equal the amount of energy from large scale solar to provide an equal comparison. From this, an overall comparison of the cost for each resource option is made, with recommendations for the options that should be pursued in the future by the SFPUC.

This analysis only reflects a portion of the output from projects modeled as part of this assessment. There are a large number of additional renewable resource options that could be available to the SFPUC. The intent is to provide a relative understanding for how the different resource types compare to one another. The supply curve showing the LCOEs under the preferred financing option (PPA with transfer) is presented in Figure 1-2.

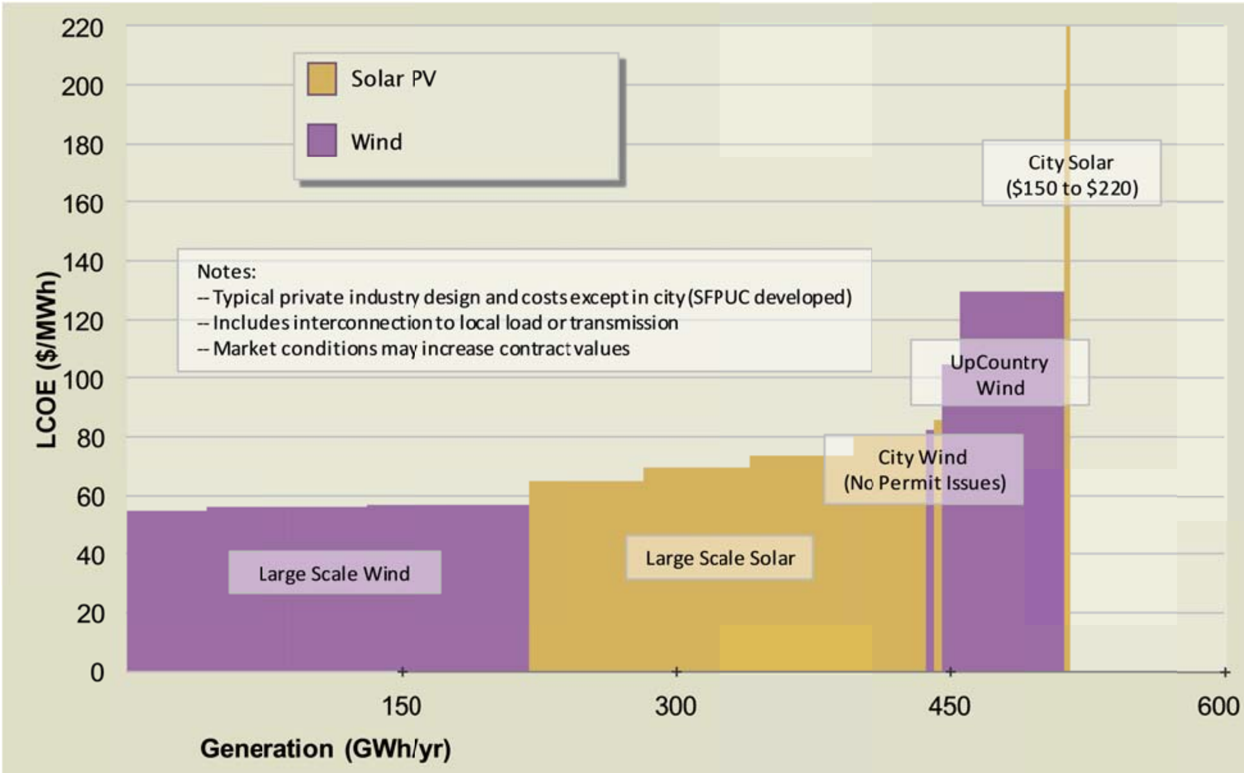

Figure 1-2 Modeled Resource Supply Curve (PPA with Transfer)

An important point about supply curves is that they indicate relative cost to develop and not necessarily the price that will be paid by the SFPUC. They are useful for ranking projects, as the projects on the left hand side of the curve will be the more profitable projects to develop if they sell their energy at market rates. For this reason, they are more likely to be developed than higher cost projects. A tabular summary of the resource ranked above can be seen in Table 1-4.

Table 1-4 Tabular Comparison of All Resources (PPA with Transfer)

NAME	TECHNOLOGY	LOCATION	SIZE (MW)	LCOE ($/MWh)
Walnut Grove	Wind	Yolo	170	54.89
Montezuma Hills	Wind	Solano	100	56.13
Newberry Springs	Wind	San Bernardino	100	56.34
Altamont	Wind (Repower)	Alameda	20	56.63
Leona Valley	Wind	Los Angeles	100	56.85
Windhub	Tracking PV	Kern	20	64.70
Imperial Valley	Tracking PV	Imperial	20	69.54
Midway	Tracking PV	Kern	20	73.50
Sunol PV	Fixed PV	SFPUC Land, Alameda	19.2	80.48
Oceanside	Wind	San Francisco	2	82.01
Tesla PV	Fixed PV	SFPUC Land, San Joaquin	1.6	85.40
Tesla Wind	Wind	SFPUC Land, San Joaquin	6	104.33
Sunol Wind	Wind	SFPUC Land, Alameda	30	129.85
Pulgas Res.	Rooftop PV	San Mateo	2.7	149.64
University Res.	Rooftop PV	San Francisco	2.9	154.39
Sutro Res.	Rooftop PV	San Francisco	2.0	168.09
Thurgood Marsh.	Rooftop PV	San Francisco	0.2	168.65
College Hill Res.	Rooftop PV	San Francisco	0.9	170.27
Stanford Heights	Rooftop PV	San Francisco	0.7	181.98
Summit Res.	Rooftop PV	San Francisco	0.7	182.15
Marina School	Rooftop PV	San Francisco	0.05	198.39
Hunters Point	Rooftop PV	San Francisco	0.005	222.67

If the SFPUC chooses not to take project ownership, the PPA finance structure would likely be used. This is a relatively simple, well-established structure that the SFPUC has used in the past. As shown below, this structure may increase the LCOE to the SFPUC, since the SFPUC's low cost of capital would not be applied towards ownership as it would in the PPA with transfer structure.

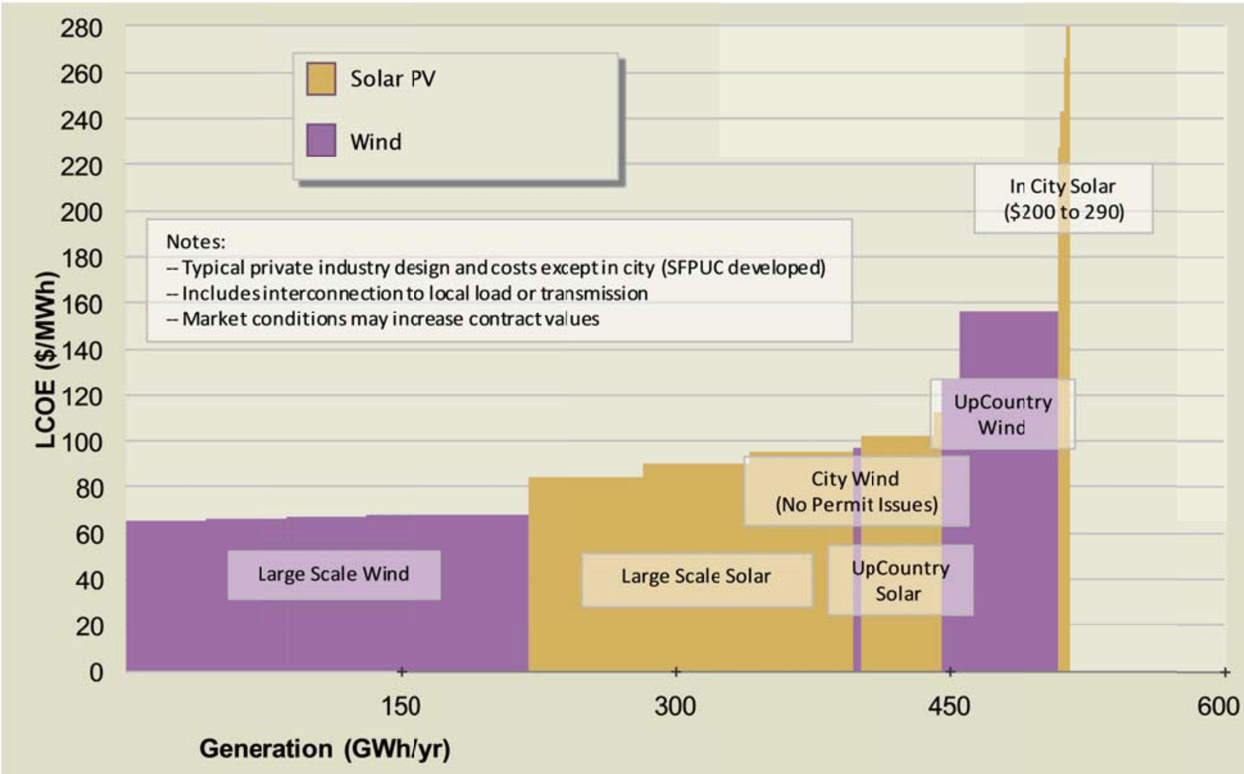

Figure 1-3 Modeled Resource Supply Curve (PPA Only)

Under this financing arrangement, the LCOE for wind projects has increased by roughly 20 percent, while the LCOEs for solar have increase by roughly 30 percent relative to a PPA with transfer. Since solar pricing increased by a greater amount relative to wind, this moved some smaller wind projects to the left on supply curve. Solar projects have higher capital costs than wind projects, which makes their LCOEs change more significantly when the cost of capital is changed.

1.4 CONCLUSIONS AND RECOMMENDATIONS

From this analysis, conclusions can be made regarding the best resource and ownership options. The PPA with transfer and prepay PPA options have lower LCOEs for all technologies when compared to straight PPAs or SFPUC ownership. Typically, municipal ownership is more expensive than the other options since municipalities are not eligible for the ITC. However, the very low cost of capital (3.8 percent) modeled for the SFPUC makes municipal ownership look competitive with a straight PPA. If the spread between the cost of capital to the SFPUC and private developers was to shrink, this options would look less attractive.

A PPA with transfer at year 7 appears to be the lowest cost financial structure for any project considered by the SFPUC at this time. However, the LCOE for the PPA with transfer is fairly sensitive to the financial assumptions, making prepay options appear more attractive if financing assumptions, such as higher debt rates, shorter loan periods, and higher levered rates of return, are modified. The SFPUC needs to weigh those risks against the complexity and risks of the contractual agreement for a prepay scenario. Prepay PPAs are complicated, have higher structuring expenses, may encounter greater IRS audit risk, are better suited for larger projects, and may place some production risk on SFPUC. Note that if the federal tax credits are removed, this would greatly reduce the incentive for the SFPUC to consider any type of PPA structure. In this case, the low cost of capital available to the SFPUC would favor self-ownership as the preferred option. Note that this analysis is preliminary and is not intended to substitute for financial advisory services which the SFPUC should secure if any of these options are pursued.

When comparing different technologies and locations, large, utility-scale facilities connected to the CAISO tend to have lower LCOEs relative to local, smaller-scale wind and solar projects located in and around San Francisco. However, other factors not quantified here such as local development and jobs, visibility, and ease of development could justify the development of more local resources.

If available for development, large wind projects are estimated to have a slight cost advantage over large solar facilities, although the projected LCOEs are very close. However, both geothermal and wind face greater development challenges relative to solar. The availability of new or operating geothermal facilities is limited, and wind projects face more challenging siting and permitting issues relative to new solar units. In addition, the wind output can be more variable; a closer look at the output profiles for different wind and solar projects can help the SFPUC to determine if there are time of generation advantages that would favor one of these resources over another.

Another option available to the SFPUC to meet future renewable energy and power requirements is to purchase both on the wholesale market. Currently, both wholesale power and REC prices in Northern California are low: US DOE EIA data for 2013 shows the average market clearing wholesale price at nearly $44/MWh, and Category 3 RECs are currently trading at around $1/MWh. If a longer-term perspective is taken into account, the economic prospects for the development of new generation improves. Black & Veatch forecasts that the 2020 wholesale Northern California power price will be roughly $54/MWh (in 2013$). REC prices are expected to remain low unless higher goals are established for the California RPS. It is becoming increasingly likely that RPS targets will rise, which may lead to higher future REC values. The best renewable energy resources identified in this analysis have LCOEs of $55 to 60/MWh, making them competitive with long-term purchases of green power. Locking in a price at this level in a long-term PPA would act as an effective hedge against volatile power and REC prices provided that the SFPUC predicts a steady future demand for additional generation.

2.0 Introduction

The SFPUC is considering a range of potential generation options to meet future renewable energy targets and load growth needs. SFPUC staff and contractors have previously identified several of the best potential technologies and development locations. In this report, Black & Veatch builds upon the previous analysis by developing updated cost and performance estimates for deployment of solar PV, wind, and geothermal technologies in areas identified as suitable. Representative low cost locations and technologies are identified, along with the ownership options and financial structures that may be attractive to the SFPUC. Supply curves provide easy comparisons between the technologies and locations being considered.

2.1 OBJECTIVE

The objective of this report is to identify and characterize various solar PV, wind, and geothermal power facilities that could be used to deliver power to the SFPUC in the future. An effort was made to select project sizes and locations to represent a wide range of options available to the SFPUC, ranging from 2.5 kW rooftop PV facilities in San Francisco to 100 MW wind projects in southern California.

2.2 APPROACH

Utilizing work previously performed by Black & Veatch as well as by the SFPUC and their consultants, resource assessments were performed for solar PV, wind, and geothermal power facilities to identify project locations and sizes that could economically deliver renewable energy to the SFPUC. The resource assessments included cost, technology, and production assessments for each project. Based on these assessments project capital and operating costs were developed. Black & Veatch then reviewed available incentives that could be utilized and assessed various ownership structures for the projects. The costs, production estimates, incentives, and ownerships structures were used to calculate the LCOE for each option. Supply curves were then developed to provide a basis of comparison for the various projects and ownership structures considered in this analysis.

3.0 Methodology

Projects were evaluated within San Francisco, on SFPUC controlled lands, and throughout the state. Statewide project analysis is based upon work recently conducted by Black & Veatch as part of the RETI and WREZ projects to assess renewable resources available to achieve California RPS goals. Previously performed resource assessments for wind, solar, and geothermal projects were updated to identify areas where economically feasible projects could be developed for the SFPUC. Transmission constraints were also considered when selecting project sizes and locations. A review of available incentives and ownership structures was performed, and the levelized cost of energy was modeled for each project. Supply curves were developed to represent the range of renewable energy options available to the SFPUC. This report section details the methodology used in this assessment.

Detailed capital cost assessments were performed for each solar and wind site, taking into account all factors included in developing a new project. While site specific factors, such as slope, terrain, and resource potential were taken into account as much as possible, it was assumed that each site would be suitable for development with few barriers. Typical private industry development costs for comparable projects were used as a starting point, with adjustments made for the prevailing wage. More stringent design requirements, differences in labor productivity, greater environmental and permitting costs, and unforeseen site technical restrictions would increase the costs beyond those estimated in this report. For in-city solar PV projects, adjustments were made to the estimated capital costs to reflect actual cost data reported by the California Solar Initiative. Geothermal cost assessments performed in previous studies for each specific location were reviewed and updated.

Estimated costs reflect the requirements to produce and deliver the power to local load or transmission, but will not reflect the delivered cost of power to San Francisco for projects outside of the city. Renewable resources delivering power using the CAISO grid will pay a transmission wheeling charge to bring the power to San Francisco. If the generator is a variable resource, as long as the resource is participating in the CAISO Participating Intermittent Resource Program (PIRP) there are no additional costs for generation variability (i.e. schedule deviation penalties or ancillary services charges). The resource should have a "full capacity" interconnection agreement with the CAISO. No Firm Transmission Rights (FTR) are required to deliver the energy, but depending on the location of the resource, congestion revenue rights (CRRs) may be required to ensure full delivery of the energy from the generating resource to SFPUC.

In addition, the cost of power reflects the cost to the developer of the project but not necessarily what the SFPUC will pay. Other factors, such as the level of supply and demand for renewable energy in California, will impact the final pricing.

3.1 RESOURCE ASSESSMENT AND PROJECT IDENTIFICATION

Wind, solar PV, and geothermal projects in California were considered for this analysis.

3.1.1 Solar Photovoltaic Project Assessment

Black & Veatch performed a cost, technology, and production assessment for solar PV projects that could potentially be built at SFPUC owned facilities, as well as provided comparisons to the cost of solar PV built on San Francisco rooftops and projects built outside of the service territory. The costs include transmission and distribution charges but does not include any charges to transmit power from the CAISO or the Hetch Hetchy distribution system into San Francisco.

The first part of this assessment includes a review and update of past studies performed for the SFPUC by other consultants. Project sizes and capital costs were developed for six SFPUC reservoirs and two upcountry locations (Sunol and Tesla); the technology assumptions and costs were updated for this study.

For comparison to facilities located on SFPUC properties, an estimate for the average cost and performance of rooftop facilities within the city was developed. Four rooftop sizes and three neighborhoods were modeled to provide a range of cost and performance estimates for rooftop facilities. Two sizes of residential rooftops were modeled in Hunters Point, and two commercial rooftops were modeled at the Marina Middle School and Thurgood Marshall School locations.

As a further point of comparison, the team developed costs for importing solar PV power from a few representative large projects located outside of San Francisco. Project data developed for the RETI and WREZ projects was used for the statewide project assessments.

3.1.2 Wind Project Assessment

Black & Veatch performed cost, technology, and production assessments for wind projects that could potentially be built at SFPUC owned facilities, and developed comparisons to projects built outside of the service territory. The costs include transmission and distribution charges; as with the solar work, costs to bring the power into San Francisco from the point of interconnect is not included.

Cost and performance estimates were made for wind sited at two upcountry locations (Sunol and Tesla), as well as for one in-city location (Oceanside WWTP). The team also identified the cost for importing power from a few representative large wind projects located at good wind resources in California within the CAISO. Project data developed for the RETI and WREZ projects was used in this analysis.

3.1.3 Geotechnical Project Assessment

Cost, technology, and production assessments were developed for several California geothermal projects that could import power to the SFPUC. The resource assessment performed for the SFPUC by GeothermEx in 2010 was used along with RETI and WREZ resource and cost comparisons[5] for the analysis. This study updates costs for each of the areas previously identified and also considers available transmission capacities and interconnection costs for each of the resource areas.

[5] Note that GeothermEx and Black & Veatch collaborated on the original RETI and WREZ geothermal assessments.

3.2 TRANSMISSION AND INTERCONNECTION

Available transmission capacity was considered when siting each of the large scale wind, solar PV, and geothermal projects. Wind and geothermal resource assessments were first performed to identify the most attractive locations and then publicly available information was consulted to verify the presence of adequate transmission capacity for each site. Interconnection costs were developed and locations with uneconomic interconnection and transmission costs were filtered out. For solar PV, since the entire state has adequate resources to support development of commercial facilities, the transmission and interconnection screen identified the least cost interconnection points. From these screens, project sizes were developed and production assessments were performed. The following paragraphs present additional information on how interconnection costs were assessed.

Using public information for the California investor owned utilities, available transmission capacity can be identified at major project substations. For each site, based on the anticipated length of the generation tie line, and interconnection substation availability with respect to proposed capacity, the most economical substations have been identified.

Substation interconnection costs were estimated primarily using the 2012 Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC) transmission cost estimating tool. The tool provides stake holder vetted high level capital cost estimates for substation equipment rated 230kV and above[6]. For the purpose of this study, the tool was expanded in accordance with the 2013 CAISO Participating Transmission Owner Per Unit Costs and Black & Veatch industry experience, to accommodate calculation of capital costs at voltage levels typical of interconnection substations[7].

The 115kV class substation base and equipment costs were developed by applying a 25 percent reduction factor to the 2012 WECC 230kV substation base and equipment values. This reduction factor accounts for decrease in equipment size and clearance requirements and is in accordance with the relative costs of the 115kV and 230kV Complete Loop-in Substations proposed in the PG&E 2013 Proposed Generator Interconnection per Unit Cost Guide[8].

Though medium voltage costs are not provided in the CAISO Participating Transmission Owner Per Unit Cost estimates, medium voltage feeder protection and bus equipment costs were included based on average values seen by Black & Veatch for California interconnection projects. Medium voltage costs include riser stands, switches, switch stands, circuit breaker, and buswork and are representative of equipment costs of medium voltage AC collection from the substation fence to the secondary winding of the substation step up transformer.

[6] WECC Transmission Capital Cost Report – Black & Veatch: http://www.wecc.biz/committees/BOD/TEPPC/External/BV_WECC_TransCostReport_Final.pdf
[7] Investor Owned Utilities Per Unit Costs – CAISO Website: http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx
[8] 2013 PG&E Per Unit Cost Guide: http://www.caiso.com/Documents/PGE_2013ProposedPerUnitCostGuide.xls

3.3 INCENTIVES AND FINANCIAL STRUCTURES

Black & Veatch developed a list of the main financial incentives available to the SFPUC and private developers, including federal, state, and local options. The restrictions and eligibility for each has been highlighted.

A range of possible ownership options for renewable energy projects supplying the SFPUC was then considered. This assessment highlights the structure, requirements, and potential benefits/drawbacks of each. The major structures considered are SFPUC ownership, PPA with and without transfer, prepay PPA (also with and without transfer), and REIT.

3.4 RESOURCE VALUATION

A pro forma economic model was developed to estimate the levelized cost of electricity for the major resource options delivered to the SFPUC service territory. The different ownership structures are modeled to provide comparisons and recommendations for the most attractive options to consider. The financial model is a detailed pro forma that allows entry of a wide range of project specific technical costs and finance assumptions to determine a range of potential levelized costs. Major inputs to the model include technical assumptions (capital cost, operating costs, capacity factor, escalation rates, etc.), owner assumptions (prepay amount, bond costs, discount rate, additional fees, etc.), and developer financial assumptions (incentives, cost of debt, cost of equity, economic life, depreciation, flip structure, etc.).

3.5 SUPPLY CURVE DEVELOPMENT

Supply curves based on the projects identified as part of the resource assessment were produced to compare the development cost of each resource. These supply curves reflect the cost of generation (not necessarily the price that the SFPUC would pay) versus the energy generation potential. From these curves, a comparison of the cost for each resource option is made, with recommendations for the options that should be pursued in the future by the SFPUC.

4.0 Solar Photovoltaic Resource Assessment

A selection of project locations and sizes were considered in this assessment to develop the technical basis for estimating cost and performance for solar PV facilities that are representative of the opportunities available to the SFPUC.

4.1 SOLAR RESOURCE ANALYSIS

To estimate solar resources and energy production in San Francisco, up country, and in-state locations, Black & Veatch used satellite data benchmarked against the met station data that has been made available by the SFPUC. Solar Anywhere was selected as the satellite data source for this assessment. Solar Anywhere is a free, publicly available data source that offers 1km resolution solar data yearly from 1998 to present in California. Using a consistent data source and format provides a basis for comparison of sites within San Francisco, upcountry, and other statewide locations. Solar Anywhere measurements have low uncertainty (+/- 5 percent for global horizontal irradiance (GHI)) which is comparable to most of the met station instrumentation. In addition, satellite data does not introduce questions around calibration, maintenance, or missing data points that accompany some of the ground based measurements.

Black & Veatch created a typical mean year (TMY) file for each project location using multiple years of satellite data, as shown below.

Table 4-1 Solar Resource Data

SITE	ANNUAL TYPICAL GHI (kWh/m^2/year)
Hunters Point	1757
Thurgood Marshall School	1730
Marina Middle School	1673
College Hill Reservoir	1730
Pulgas Balancing Reservoir	1827
Sutro Reservoir*	1639
University Mound Reservoir	1735
Stanford Heights Reservoir	1635
Summit Reservoir*	1639
Sunol	1854
Tesla	1893
Wind Hub	2114
Imperial Valley	2143
Midway	1992

***Due to the proximity of Sutro and Summit reservoirs the same TMY file was used for these sites.**

To provide a basis for comparison, the GHI measurements obtained from Solar Anywhere are compared to two other publicly available satellite datasets, Solar Prospector and NASA Surface meteorology and Solar Energy (SSE), in Table 4-2. Solar Anywhere uses newer algorithms than what was used when deriving the Solar Prospector dataset. The NASA SSE dataset uses a different algorithm for estimating GHI and a much coarser grid size, leading to higher uncertainty.

Table 4-2 Satellite Based GHI [kWh/m^2/yr] by Source

LOCATION	SOLAR ANYWHERE	SOLAR PROSPECTOR	NASA SSE
Hunters Point	1757	1745	1670
Thurgood Marshall School	1730	1745	1670
Marina Middle School	1673	1768	1670
College Hill Reservoir	1730	1588	1670
Sutro and Summit Reservoirs	1639	1588	1670
University Mound Reservoir	1735	1588	1670
Stanford Heights Reservoir	1635	1588	1670

Each satellite data source averages readings across a geographic area. Solar Anywhere data is averaged across 1 km grid squares, which provides enough granularity to model individual neighborhoods within San Francisco. Solar Prospector data aggregates data on a roughly 10 km grid. The Solar Prospector grid that captures the College Hill, Sutro, Summit, University Mound, and Stanford Heights reservoirs covers much of San Francisco and aggregates readings from neighborhoods that are largely sunny with those that experience greater amounts of fog cover (Grid Number 1 in Figure 4-1). In Figure 4-1, the Hunters Point and Thurgood Marshall School locations are captured in Grid Number 2, while Marina Middle School is located in Grid Number 3. NASA SSE data is aggregated on a larger scale, and all of the representative San Francisco project locations are characterized with the same grid in that data set. A comparison of the Solar Anywhere GHI values with the Solar Prospector GHI values for sites located in Grid Number 1 shows that the Solar Anywhere values are equivalent or higher for most sites. However these values are likely to be more representative of the solar resource in those neighborhoods than Solar Prospector because of the averaging effect of the larger grid square.

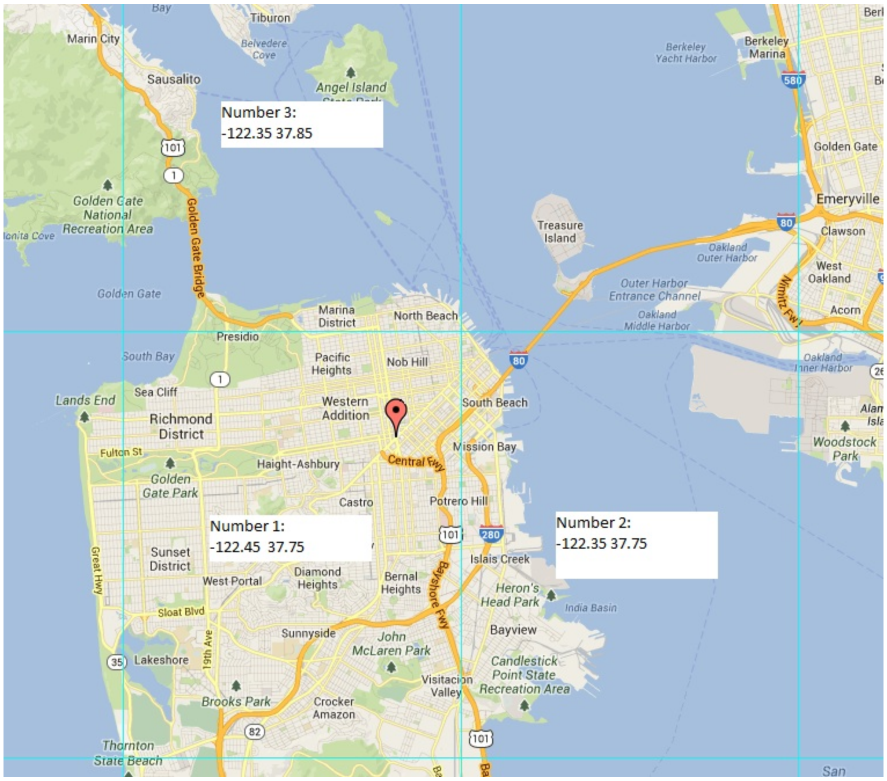

Figure 4-1 NREL Solar Anywhere 10 km Grid

For these reasons, Black & Veatch chose the more granular Solar Anywhere data for the analysis. However, the output and capacity factor estimate shown in this report may be higher than past studies and installations for two main factors. The first is the difference in datasets outlined above. Second, the designs developed in this study reflect state-of-the-art, new designs which are likely to have higher output than older facilities. This is largely due to the lower capital cost for solar panels, which lead to higher inverter loading ratios. Current designs find it economic to increase the number of panels in a given facility to increase output during the shoulder periods of the day. While this sacrifices a small amount of output at the peak, the net effect is greater overall output and improved system economics.

One final item to keep in mind is that all solar PV analysis is based on the assumption that the sites would be good candidates for PV: south facing, no roof upgrades, few obstructions, and typical losses and maintenance requirements. Recent in-city designs which are projected to potentially have lower capacity factors than those estimated in this report are not due to major differences in the solar resource data, but rather different assumptions for tilt, azimuth, shading, and soiling.

4.2 TECHNOLOGY DESCRIPTION

There were four different applications identified in this project as listed in Table 4-3. The module technology assumed for all systems is crystalline silicon modules. The technical characteristics of the photovoltaic systems in this table are described in the sections below. Black & Veatch notes that the technology descriptions are of general nature and the systems developed with these features are at a conceptual level. The objective in this study is to provide an indication of the systems size and cost based on commercially available equipment and typical construction methods used in the solar industry as of the writing of this report.

Table 4-3 Solar System Applications

TYPE	SIZE
Residential rooftops	2.5 – 5 kWac
Large rooftop systems for schools	50 – 200 kWac
Large rooftop systems for reservoirs	0.7 – 2.9 MWac
Utility scale, ground mounted systems	1.6 – 20 MWac

4.2.1 Residential Rooftop Systems

This report considers two residential rooftop options – a 2.5 kWac system and a 5 kWac system. The size of the systems is typical of residential applications in California. The expected life time of the system is 25 years using poly-crystalline silicon modules rated at 230Wdc each. The total number of modules is 13 for the 2.5 kWac system, requiring about 230 square feet of available area. This system size and rooftop space requirements are doubled for the 5 kWac system. The modules are flush mounted on an aluminum rack, elevated less than 12 inches from the house's roof, following the roof's tilt. To model production the roof was assumed to have a tilt of 10 degrees. For construction productivity and installation costs, it was assumed that the support of the solar rack was built-in the roof at the time of the house's construction (solar ready roof). There is one inverter per system which will have to be replaced approximately at year 12 after commissioning. The typical standard warranty for these inverters is 10 years. The inverters are service free, and require full replacement in case of failure or at the end of inverter life. This is in contrast to larger inverters which can be repaired and maintained during their lifetime. The inverters tie in to the household electrical mains, on the house side of the meter. The meter has bi-directional (net metering) capabilities.

4.2.2 Commercial Rooftop Systems

This report considers two commercial rooftop options – a 50kWac system and a 200 kWac system. The size of the systems was defined using as a reference two specific schools in San Francisco: Marina Middle School in the Marina District and Thurgood Marshall High School in the Silver Terrace District. The expected life time of the systems is 25 years using poly-crystalline silicon modules rated at 250Wdc each. The 50 kWac system comprises 224 modules, requiring less than 4,000 square feet of available roof area. The 200 kWac system utilizes 896 modules, requiring about 15,750 square feet of rooftop space. The modules are mounted on metal structures with one module mounted on landscape position and tilted 10 degrees. The structures selected are typically used on rooftop applications. They are attached to the roof through ballasts (concrete blocks) and few anchor points to the structural members of the roof. It is assumed that building structure is able to support the added weight of the solar system. It is also assumed that the roof membrane is in good conditions and that only minimal roof preparations are required before installing the system. No structural or roof retrofits were included in the cost estimates. There is one 50 kWac inverter for the smaller system and two 100 kWac inverters for the larger system. The inverters can be installed on the roof or next to the interconnection point. The inverters will have to be refurbished (some components will be replaced) approximately at year 12 after commissioning but they are expected to last the life of the PV system. The typical warranty of these inverters is 5 years standard with optional purchase of extended warranties for up to 20 years after the end of the first 5 years. The typical maintenance schedule is one to two times per year. In case of failures, repairs are made on site. Typically, the inverters will tie-in to the existing electrical infrastructure with no major retrofits required. A new meter may have to be installed with bi-directional capabilities for net-metering.

4.2.3 Large Rooftop Systems for Reservoirs

The size of the systems was defined using six specific water reservoirs in San Francisco, based on available areas previously developed by consultants to the SFPUC. The reservoirs considered in this study are:

- College Hill
- Summit
- Stanford Heights
- Sutro
- University Mound
- Pulgas

The reservoir roofs have a low weight bearing capacity and limited surface area. Because of this, the system specifications for these cases are based on standard components built by SunPower Corporation specifically for light-weight rooftop applications. Other vendors can provide equivalent systems. The expected life time of the systems is 25 years using mono-crystalline silicon modules rated at 320 Wdc each. The total number of modules ranges between 2,696 for the smallest system (666 kWac) at the Summit reservoir to 11,672 for the largest system (2,880 kWac) at University Mound. The modules are mounted on pre-engineered structure built of a polymer material. The modules are mounted at a 5 degree tilt to minimize wind loads and maximize surface area coverage. Due to the low tilt and inter-locking features of the units, the structures are not attached to the roof. Few anchor points to the structural members of the roof were considered. It is assumed that building structure is able to support the added weight of the solar system. It is also assumed that the roof membrane is in good conditions and that only minimal roof preparations are required before installing the system. No structural or roof retrofits were included in the cost estimates. The inverters used for these systems are rated at 100 kWac, 250 kWac and 500 kWac. The inverters would be installed on the ground. The inverters will have to be refurbished approximately at year 12 after commissioning but they are expected to last the life of the PV system. The typical warranty of these inverters is 5 years standard with optional purchase of extended warranties for up to 20 years after the end of the first 5 years. The typical maintenance schedule is one to two times per year. In case of failures, repairs are made on site. Typically, the inverters will tie-in to the existing electrical infrastructure with no major retrofits required. A new meter may have to be installed with bi-directional capabilities for net-metering.

4.2.4 Utility Scale Ground Mounted Systems

The size of the systems was defined for two specific SFPUC properties – Sunol and Tesla. Additionally, a conceptual 20 MWac system was assumed as part of the statewide resource assessment.

The Tesla and Sunol sites are open land. The area available to build a PV system at each site is approximately 100 acres at Sunol and 8 acres at Tesla. The area for construction is assumed to be mostly flat. The expected life time of the systems is 25 years using poly-crystalline silicon modules rated at 300 Wdc each. The construction approach is based on building blocks. Each building block is an independent system rated at 1.6 MWac and integrated by 6,840 modules and two inverters, 800 kWac each. The modules are mounted on metal structures. Both fixed tilt and single-axis tracker systems were evaluated.

For the fixed tilt system, two modules are mounted in portrait orientation (vertically stacked) facing due south with a fixed tilt of 27 degrees at the SFPUC locations and 25 degrees for the statewide locations.

For the single-axis tracker system, one module is mounted on a beam that rotates the modules East to West, following the daily sun-path. In this manner, the modules have a greater exposure to the sun on a daily basis, which increases the energy production of the system. Single-axis trackers are more expensive than fixed tilt systems and require more land.

The structures selected for both type of mounting structures are typically used on utility-scale applications. They are supported by metal beams that are driven into the ground. It is assumed that the topography of the site is mostly flat such that costs to level the terrain are not significant relative to the costs of the project (less than 2 percent). It is also assumed that the soil conditions are not corrosive and of adequate consistency to use driven pile foundations. Minimal civil works and minimal environmental permitting processes were assumed. There is a total of 1 block considered for Tesla and 12 blocks for Sunol. The estimated surface area required for these systems is 5.25 acres per MWac for the fixed tilt and 6.8 acres per MWac for the single-axis. The inverters would be installed outdoors or enclosed inside a special container. The inverters will have to be refurbished (some critical components will have to be replaced) approximately at year 12 after commissioning but they are expected to last the life of the PV system. The typical warranty of these inverters is 5 years standard with optional purchase of extended warranties for up to 20 years after the end of the first 5 years. The typical maintenance schedule is one to two times per year. In case of failures, repairs are made on site. In a typical electrical design of a utility-scale system the output of the inverters is connected to a medium voltage transformer. The power output of all the blocks in the system is collected in an AC collector station and then routed to the point of interconnection. The PV system was assumed to be co-located with the point of interconnection. No new transmission line infrastructure was included in the cost estimates. The cost for a substation to interconnect was included for Sunol.

4.3 RESOURCE AVAILABILITY

Solar PV technologies use direct and indirect irradiance to generate electricity. Therefore the GHI was characterized for this study.

4.3.1 California Solar Resource Potential

Figure 4-2 presents the GHI for California, with several projects identified for reference. For solar PV projects, resource availability is typically not the deciding factor in choosing where to site a project. Transmission constraints typically have greater influence on project siting.

4.3.2 San Francisco Solar Resource Potential

San Francisco has good solar resource potential, and benefits from cooler weather during the clearest days which enables solar panels to generate electricity more efficiently than in hotter climates. A variety of locations within San Francisco were modeled for this study and were found to have typical annual GHI reading from 1636 kW/m^2 to 1757 kW/m^2 as shown in the figure below based on NREL data.

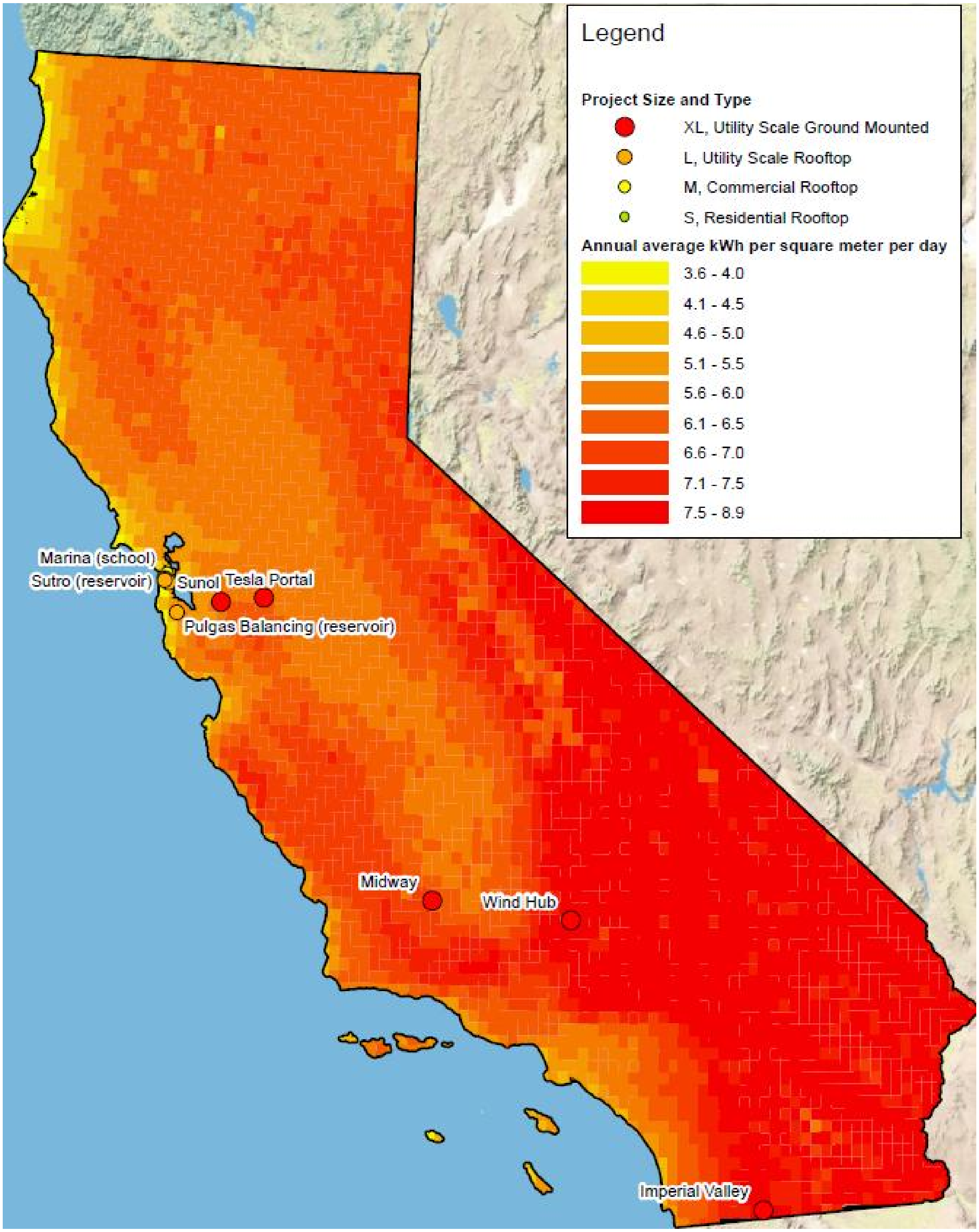

Figure 4-2 Annual Global Horizontal Irradiance in California

4.4 IN CITY COST AND PERFORMANCE CHARACTERISTICS

The PV systems considered for the city were derived from discussions with SFPUC. There were three different applications identified in this project as listed in Table 4-4. These options are meant to represent some of the roof types available within the city. The location of each application is shown in Figure 4-3.

Table 4-4 In-City Solar System Applications

TYPE	SIZE	LOCATION
Residential size	2.5kWac/ 5 kWac	Hunters Point – Residential development
Large rooftop systems for schools	50 kWac/ 200 kWac	Marina Middle-School (Marina District) Thurgood Marshall High School (Silver Terrace District)
Large rooftop systems for reservoirs	670 kWac - 2.9 MWac	College Hill Reservoir Summit Reservoir Stanford Heights Reservoir Sutro Reservoir University Mound Reservoir Pulgas Balancing Reservoir

Black & Veatch developed conceptual designs for each of the systems to estimate installed costs. These designs were also the basis to developed electrical energy production estimates using the solar resource data discussed in Section 4.3. Black & Veatch also reviewed system design and costs estimates made for the reservoirs and prepared by AEPC Group, LLC in September 2011. This section includes the estimates found in those reports and the updates made by Black & Veatch. Major updates include the following:

- The costs estimates provided by AEPC Group are outdated. The price of photovoltaic modules has decreased significantly since 2011. In addition, the price of balance of systems equipment has also dropped and the construction methods have improved.
- The efficiency of modules has also increased, which provides a higher power density (W/sq. ft.) than the 2011 modules.
- There are some differences in the estimates of surface area available as reported by AEPC Group and found by Black & Veatch for several reservoirs. Based on measurements derived from aerial images (Google Earth) and discussions with the SFPUC, Black & Veatch made updates to the previous estimates where appropriate. In most cases the previous assumed area was maintained for this study.
- Black & Veatch received guidance from SFPUC to use the interconnection and structural assumptions laid out in the AEPC reports.

Figure 4-3 Map of In-City Locations and Pulgas

Detailed capital cost assessments were performed for each solar site. The initial basis for all in-city cost estimates was typical private industry development costs and labor productivity. These cost estimates were then adjusted based on actual development cost factors for projects installed in San Francisco as part of the CSI program.[9] A summary of the 2013 CSI capital cost data, in $/kWdc, for projects 250 kW or smaller in locations throughout California is shown below. Differences between the original estimates and the CSI data were used to adjust in-city costs.

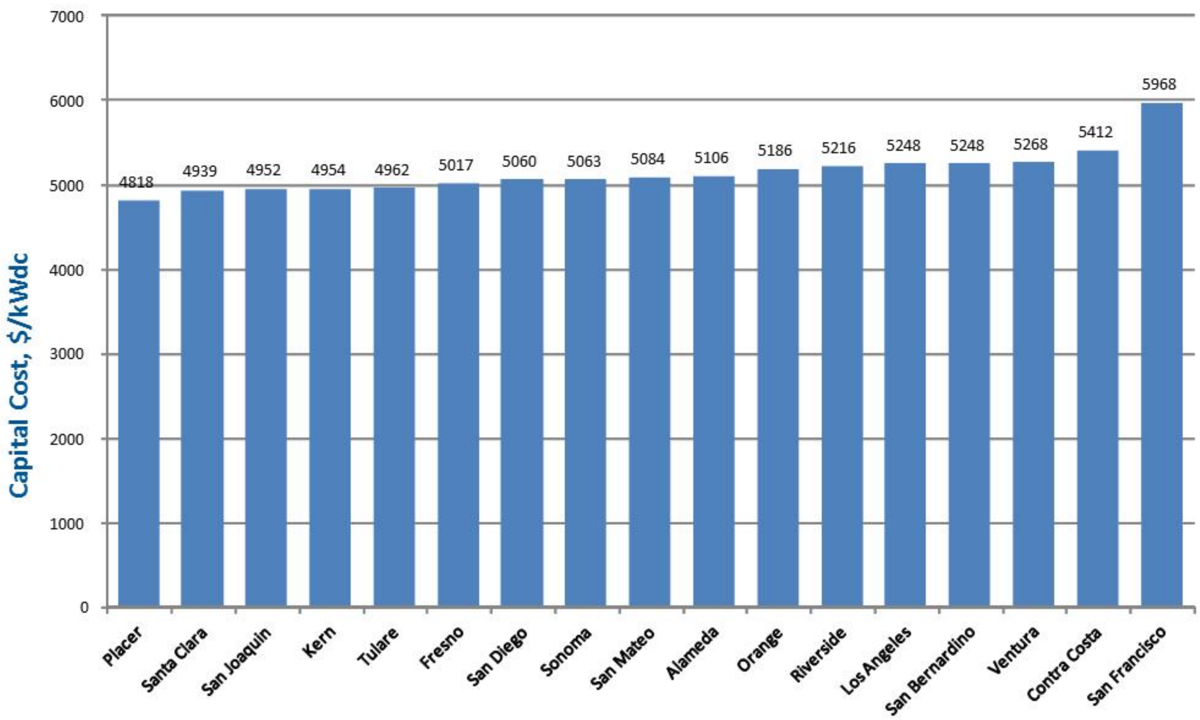

Figure 4-4 CSI Average 2013 Solar PV Capital Costs, 0 to 250 kW ($/kWdc)

For San Francisco, this data indicates that for many rooftop projects, the capital cost averaged roughly $6/Wdc, equivalent to about $7.7/Wac. These costs take into account prevailing wages, productivity, and system design requirements. While projects that will be installed on SFPUC reservoirs will be larger than the systems reported by the CSI, similar cost factor adjustments for San Francisco remain relevant for SFPUC developed projects as confirmed with SFPUC staff.

4.4.1 Hunters Point Development

Development of rooftop solar PV on new residential construction in the Hunters Point neighborhood was evaluated. The residential systems are highly variable in terms of orientation (tilt and azimuth) due to the diversity of roof's orientations. Because most roofs in the city of San

[9] Data is available at http://www.californiasolarstatistics.ca.gov/current_data_files/

Francisco are built with similar structural design and materials, the mounting features and electrical design are relatively similar independently of the tilt and orientation. There are variations in installed system costs due to different supplier and integrator prices, design and construction productivity, and economies of scale for large procurement volumes. Black & Veatch's estimates are meant to provide an average system cost.

Table 4-5 Hunters Point Development PV Design and Performance Assumptions

PARAMETER	2.5 KWAC SYSTEM	5 KWAC SYSTEM
Total Area (sq. ft.)	230	460
Module Type	Poly-crystalline (230 W)	
Mounting Type	Flush mounted | 10 degrees | Facing South-southwest (35 deg. azimuth)	
TMY - GHI (W/m^2)	1,757	
PV System Size (kWac)	2.5	5
AC Capacity Factor (percent)	20.3	20.3
Energy Yield (kWh/kWp)	1,490	1,490
Production (kWh/yr)	4,455	8,910
Capital Cost (2013$)	18,410	36,825

There may also be potential for development of ground mounted solar in the Hunters Point area. Parcel E, a 138 acre piece of land largely used for landfill in the past, could host a large solar array. Detailed investigation of the potential for this site to develop and interconnection was not performed; however, the size and location of the site could be attractive for a large scale solar project close to SFPUC load. The challenges in developing a project on a former Superfund landfill site and the lower solar irradiance relative to the other ground mounted sites considered would likely lead to higher costs relative to other large-scale options evaluated in this report.

4.4.2 School Buildings

Large flat roofs are found extensively throughout the city of San Francisco. These buildings tend to be warehouse type of structure or concrete buildings. The buildings considered for this study are school buildings (typically concrete), which are within SFPUC's jurisdiction. The orientation of the buildings may not be the best relative to optimal solar gain (building roof aligned on a true North-South axis). Therefore, the geometry of the solar system relative to the geometry and orientation of the building may be the same or different. Matching the geometry of the solar system to the geometry of the roof's building will maximize the power density of the solar system. However, this can cause a misalignment of the solar system to the optimal orientation (modules not facing true South), which will reduce the energy production. Because the roofs are flat, it is possible to align the solar system to the optimal orientation although this would reduce the capacity of the system. Black & Veatch assumed an optimal orientation for the school systems, that is, the modules are facing true South.

For the electrical interconnection, Black & Veatch assumed that there is enough space and capacity for a bus tap at the existing electrical switchgear of the building. Only minor electrical infrastructure retrofits are included in the costs estimates. The interconnection would be at 480 Vac (3 phases).

Black & Veatch assumed that the buildings have the structural capacity support the static (weight) and dynamic (wind) loads added by the solar system. No structural retrofits were included in the system costs estimates. Black & Veatch also assumed that the roof membrane is in good conditions and that only minor repairs, including those caused by construction damages and anchoring of the mounting structure, are required before, during and after installing the solar system.

There are variations in installed system costs due to different supplier and system integrator prices, design and construction productivity and economies of scale for large procurement volumes. Black & Veatch's estimates are meant to provide an average system cost. For the school systems, Black & Veatch did not assumed economies of scale and considered that the equipment and material procurement only applied to the specific project. However, some discount in equipment price, design and labor productivity was given assuming the project is developed by an experienced solar integrator.

Table 4-6 School Buildings PV Design and Performance Assumptions

PARAMETER	MARINA MIDDLE SCHOOL 50 KWAC SYSTEM	THURGOOD MARSHALL 200 KWAC SYSTEM
Total Area (sq. ft.)	4,000	15,800
Module Type	Poly-crystalline (250 W)	
Mounting Type	Fixed tilt | ballasted | 10 degrees | Facing South (0 deg. azimuth)	
TMY - GHI (W/m^2)	1673	1,730
PV System Size (kWac)	50	200
AC Capacity Factor (percent)	21.1	22.3
Energy Yield (kWh/kWp)	1,421	1,500
Production (kWh/yr)	92,337	390,014
Capital Cost (2013$)	362,250	1,233,000

4.4.3 Reservoirs

Black & Veatch considered six specific water reservoirs within the city of San Francisco as indicated by the SFPUC. The water reservoirs have large flat roofs, which makes them ideal candidates for solar systems. However, as indicated by the AEPC Group's reports, the structural capacity of these roofs is limited to less than 6 pounds per square foot (psf). In the case of the

College Hill reservoir, the recommended load is up to 2.7 psf. Black & Veatch did not review any structural information for these buildings and used the guidelines in the AEPC Group's reports.

To address the low weight capacity of the reservoirs' roof, Black & Veatch assumed the use of the T5 product manufactured and sold by SunPower Corporation. The selection of this equipment to develop conceptual designs does not imply any recommendation on the part of Black & Veatch to use this equipment. Other vendors may offer an equivalent or better solution. In the reports developed by AEPC Group, the module and mounting structure selected appear to no longer exist in the market. Other major assumptions include the following:

- Optimal orientation of the modules (South facing) and approximately 95 percent coverage of the total roof surface. Based on aerial images, the roofs appear to be relatively free of equipment. Shading from nearby objects that may limit the system was not considered for this preliminary assessment. Roof conditions, roof objects, shading and structural capacity are key features that will have to be assessed in detail for project development and construction.
- The electrical interconnection characteristics were taken from the AEPC Group's reports, which considered a tie-in to a nearby PG&E substation with a 480 Vac distribution section. Only minor electrical infrastructure retrofits are included in the cost estimates.
- The roof is in good condition and that only minor repairs, including those caused by construction damages and anchoring of the mounting structure, are required before, during and after installing the solar system.
- There are variations in installed system costs due to different supplier and system integrator prices, design and construction productivity and economies of scale for large procurement volumes. Estimates are meant to provide an average system cost. Discounts are applied to the cost due to the large scale of each reservoir system.

Google Earth images, solar irradiance, system size, capacity factor, production, and cost estimates for each reservoir are shown on the following pages.

College Hill Reservoir - College Hill reservoir is a single, large oval shaped building with a flat roof as shown in Figure 4-5.

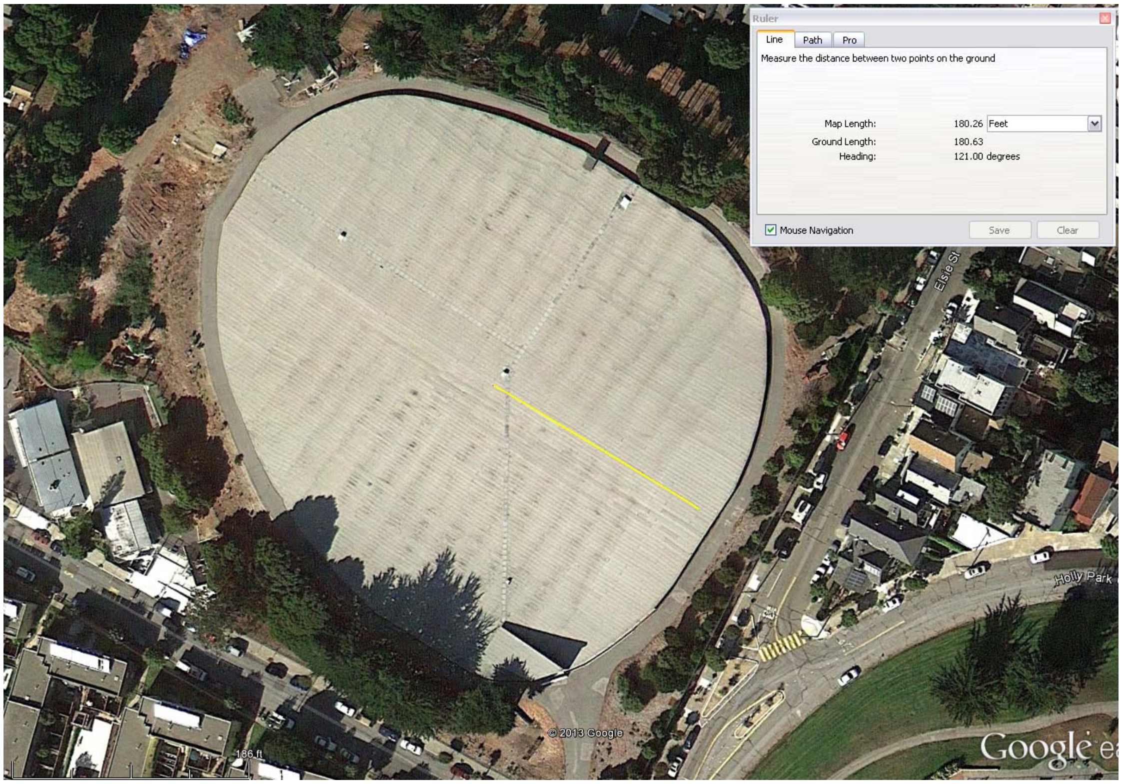

Figure 4-5 College Hill Reservoir

Table 4-7 College Hill Reservoir Design and Performance Assumptions

PARAMETER	PREVIOUS ASSUMPTION	UPDATED ASSUMPTION
Net area for PV (sq. ft.)	104,000	No change
Module Type	Mono-crystalline (450 W)	Mono-crystalline (320 W)
Mounting Type	Roofing membrane | Module built-in | SolarSave	Polymer structure, built-in | SunPower T5
TMY - GHI (W/m^2)	Not Reported	1,730
PV System Size (kWac)	500	895
AC Capacity Factor (percent)	Not Reported	20.8
Energy Yield (kWh/kWp)	Not Reported	1,405
Production (kWh/yr)	Not Reported	1,628,788
Capital Cost (2013$)	6,500,000	5,370,000
Capital Cost ($/Wp)	10.03	4.63
Capital Cost ($/Wac)	13.00	6.00

Summit Reservoir - Summit reservoir is a single, large rectangular/octagonal shaped building with a flat roof as shown in Figure 4-6.

Figure 4-6 Summit Hill Reservoir

Table 4-8 Summit Reservoir Design and Performance Assumptions

PARAMETER	PREVIOUS ASSUMPTION	UPDATED ASSUMPTION
Net area for PV (sq. ft.)	77,400	No change
Module Type	Mono-crystalline (450 W)	Mono-crystalline (320 W)
Mounting Type	Roofing membrane | Module built-in | SolarSave	Polymer structure, built-in | SunPower T5
TMY - GHI (W/m^2)	Not Reported	1,639
PV System Size (kWac)	500	664
AC Capacity Factor (percent)	Not Reported	19.7
Energy Yield (kWh/kWp)	Not Reported	1,329
Production (kWh/yr)	Not Reported	1,146,590
Capital Cost (2013$)	6,500,000	4,033,800
Capital Cost ($/Wp)	10.03	4.68
Capital Cost ($/Wac)	13.00	6.08

Stanford Heights Reservoir+ - Stanford Heights reservoir is a single, large trapezoid shaped building with a concrete flat roof as shown in Figure 4-7.

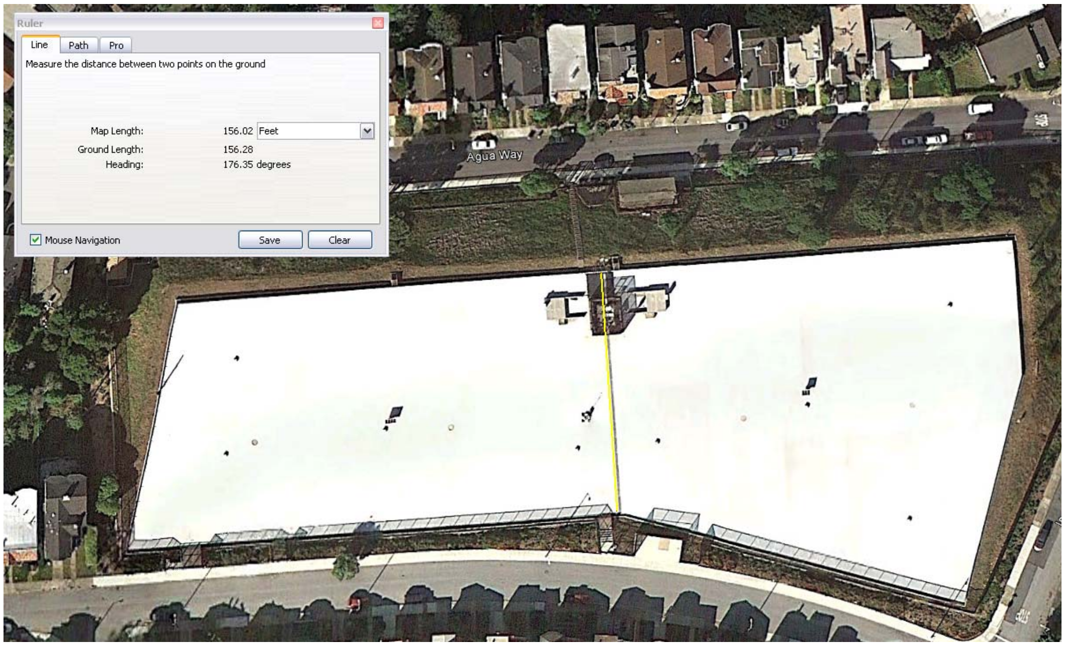

Figure 4-7 Stanford Heights Reservoir

Table 4-9 Stanford Heights Reservoir Design and Performance Assumptions

PARAMETER	PREVIOUS ASSUMPTION	UPDATED ASSUMPTION
Net area for PV (sq. ft.)	138,000	81,750
Module Type	Mono-crystalline (450 W)	Mono-crystalline (320 W)
Mounting Type	Roofing membrane | Module built-in | SolarSave	Polymer structure, built-in | SunPower T5
TMY - GHI (W/m^2)	Not Reported	1,635
PV System Size (kWac)	1,000	704
AC Capacity Factor (percent)	Not Reported	19.6
Energy Yield (kWh/kWp)	Not Reported	1,326
Production (kWh/yr)	Not Reported	1,208,475
Capital Cost (2013$)	6,500,000	4,266,240
Capital Cost ($/Wp)	10.03	4.68
Capital Cost ($/Wac)	13.00	6.06

Black & Veatch notes that there is a significant discrepancy in the estimated net surface area for the solar system. Approximations of available surface roof area using Google Earth indicates a much smaller available area than quoted by AEPC.

Sutro Reservoir - Sutro reservoir is a single, large rectangular shaped building with a flat roof as shown in Figure 4-8.

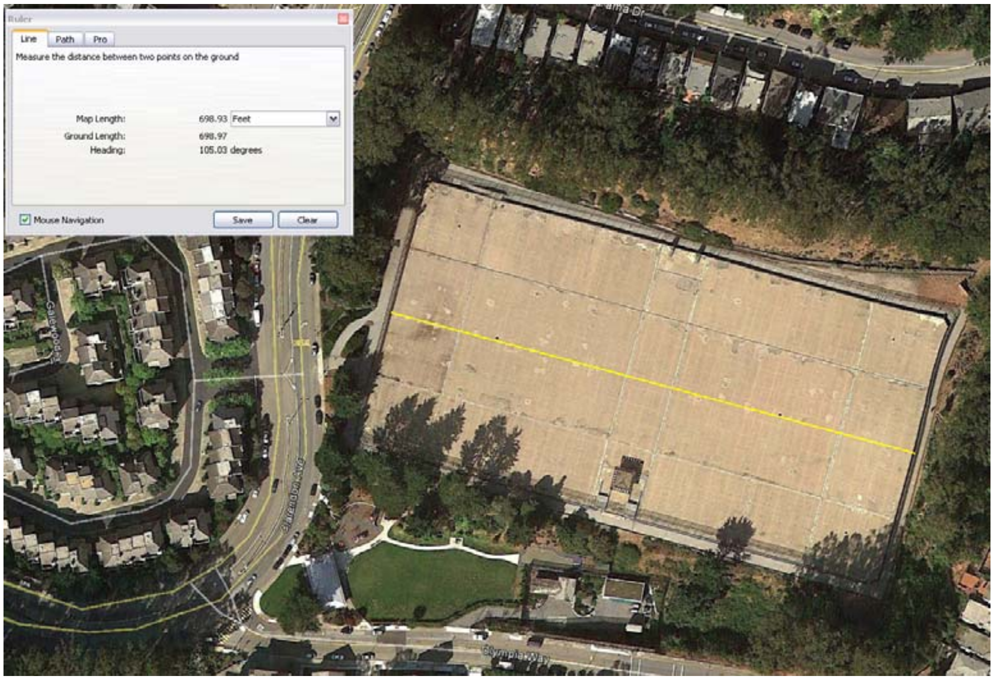

Figure 4-8 Sutro Reservoir

Table 4-10 Sutro Reservoir Design and Performance Assumptions

PARAMETER	PREVIOUS ASSUMPTION	UPDATED ASSUMPTION
Net area for PV (sq. ft.)	233,600	No change
Module Type	Mono-crystalline (450 W)	Mono-crystalline (320 W)
Mounting Type	Roofing membrane | Module built-in | SolarSave	Polymer structure, built-in | SunPower T5
TMY - GHI (W/m^2)	Not Reported	1,639
PV System Size (kWac)	1,500	2,010
AC Capacity Factor (percent)	Not Reported	19.7
Energy Yield (kWh/kWp)	Not Reported	1,329
Production (kWh/yr)	Not Reported	3,460,183
Capital Cost (2013$)	19,500,000	11,155,500
Capital Cost ($/Wp)	10.03	4.29
Capital Cost ($/Wac)	13.00	5.55

University Mound Reservoir - University Mound reservoir is a single, rectangular shaped building with a flat roof as shown in Figure 4-9.

Figure 4-9 University Mound Reservoir

Table 4-11 University Mound Reservoir Design and Performance Assumptions

PARAMETER	PREVIOUS ASSUMPTION	UPDATED ASSUMPTION
Net area for PV (sq. ft.)	192,000	335,250
Module Type	Mono-crystalline (450 W)	Mono-crystalline (320 W)
Mounting Type	Roofing membrane | Module built-in | SolarSave	Polymer structure, built-in | SunPower T5
TMY - GHI (W/m^2)	Not Reported	1,735
PV System Size (kWac)	1,500	2,883
AC Capacity Factor (percent)	Not Reported	20.8
Energy Yield (kWh/kWp)	Not Reported	1,408
Production (kWh/yr)	Not Reported	5,259,054
Capital Cost (2013$)	19,500,000	15,524,000
Capital Cost ($/Wp)	10.03	4.16
Capital Cost ($/Wac)	13.00	5.39

It is unclear why the AEPC Group considered a smaller surface area relative to the potential roof size.

Pulgas Balancing Reservoir – Pulgas Balancing reservoir is a single, square shaped building with a flat roof as shown in Figure 4-10.

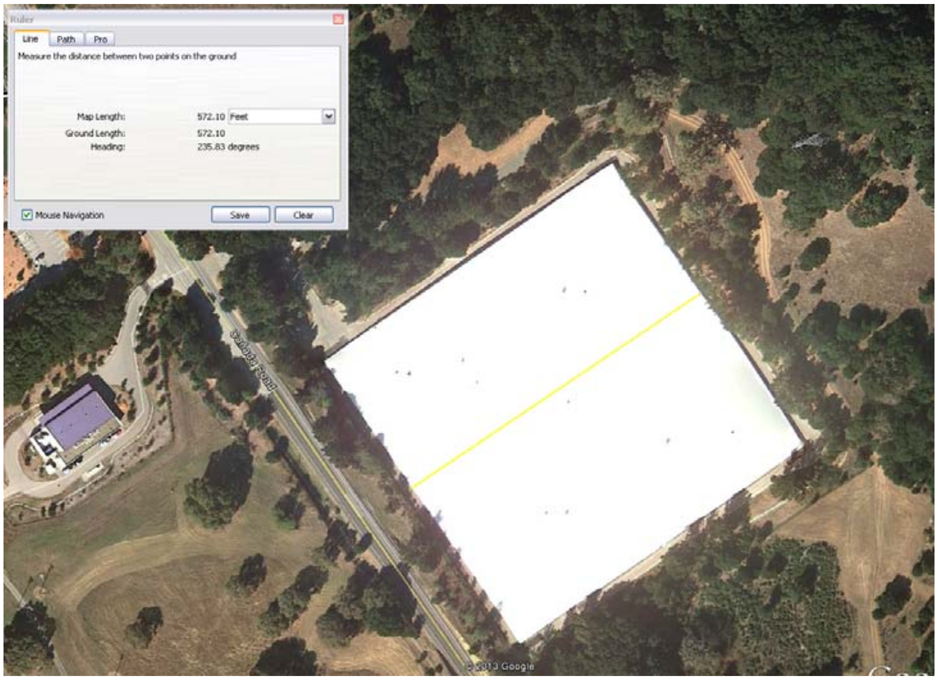

Figure 4-10 Pulgas Balancing Reservoir

Table 4-12 Pulgas Balancing Reservoir Design and Performance Assumptions

PARAMETER	PREVIOUS ASSUMPTION	UPDATED ASSUMPTION
Net area for PV (sq. ft.)	255,380	No change
Module Type	Mono-crystalline (450 W)	Mono-crystalline (320 W)
Mounting Type	Roofing membrane | Module built-in | SolarSave	Polymer structure, built-in | SunPower T5
TMY - GHI (W/m^2)	Not Reported	1,827
PV System Size (kWac)	2,000	2,650
AC Capacity Factor (percent)	Not Reported	21.5
Energy Yield (kWh/kWp)	Not Reported	1,453
Production (kWh/yr)	Not Reported	4,987,126
Capital Cost (2013$)	25,500,000	14,270,000
Capital Cost ($/Wp)	9.84	4.16
Capital Cost ($/Wac)	12.75	5.39

4.5 UPCOUNTRY COST AND PERFORMANCE ESTIMATES

The up country sites considered for PV system development were derived from discussions with SFPUC. The up country systems are ground mounted, utility-scale systems at two locations, Tesla Portal and Sunol Valley as show in Figure 4-11.

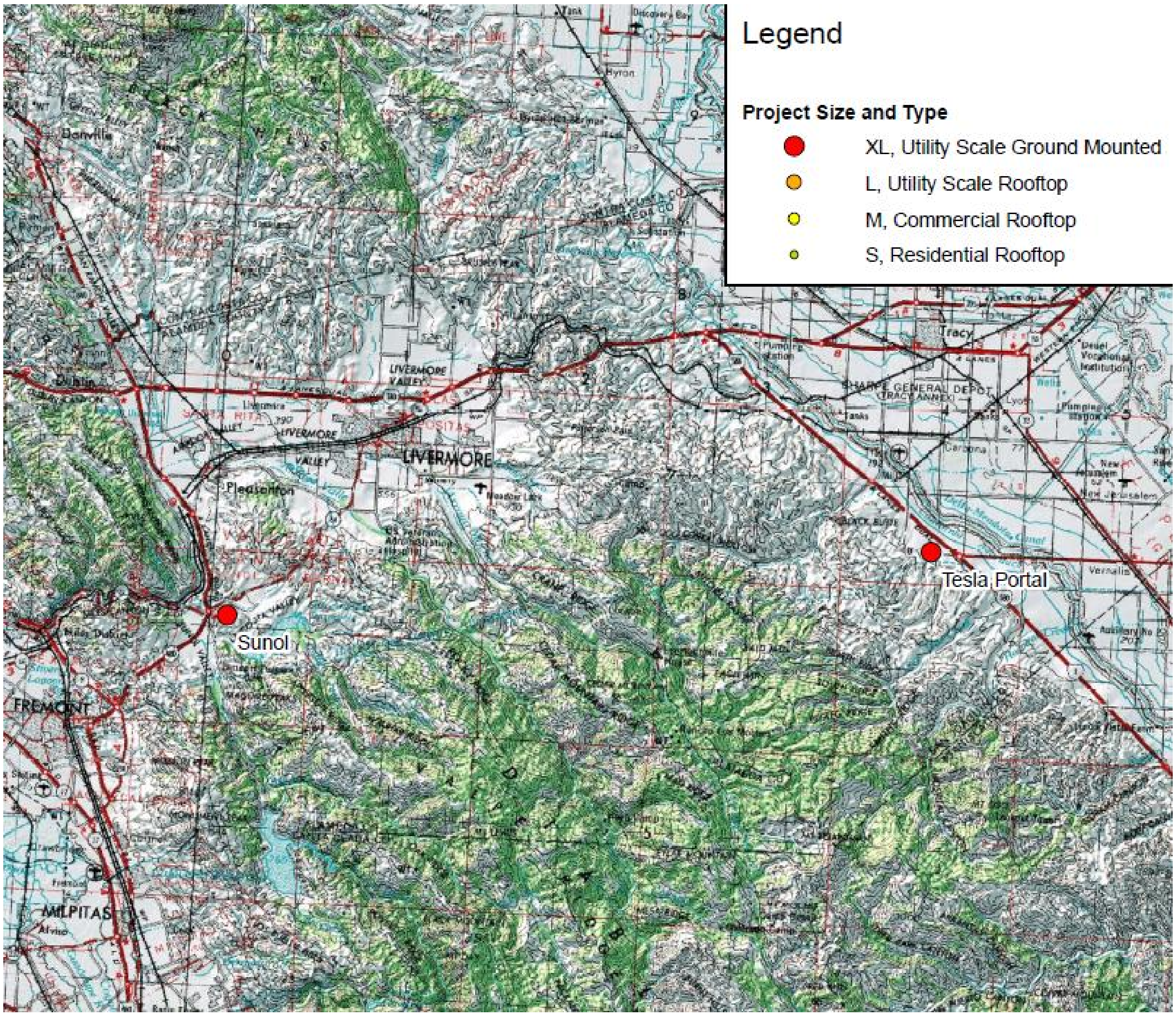

Figure 4-11 Map of Upcountry Project Sites

Black & Veatch developed conceptual designs for the two systems to estimate installed costs. These designs were also the basis to develop electrical energy production estimates using the solar resource data discussed in Section 4.3. The key assumptions made for each of the systems and the results are described below.

- The cost estimates provided by AEPC Group are outdated. The price of photovoltaic modules has decreased significantly in the last few years. In addition, the price of balance of systems equipment has also dropped and the construction methods have improved. Detailed capital cost assessments were performed for each solar site using typical private industry development costs and labor productivity. Unlike the in-city cost estimates, no adjustments were made to reflect higher SFPUC prices.

- The efficiency of modules has also increased, which provides a higher power density (W/sq. ft.) than the 2011 modules. Black & Veatch notes that AEPC Group's assumptions on surface area required for the PV system are now unrealistic.
- Based on the maps provided to Black & Veatch, it appears that there is not enough land available to reach the design capacity identified by AEPC.
- The sites are assumed to be relatively flat with adequate soil consistency for the use of driven piles. Relatively simple site preparations (vegetation removal, earth works, grading, etc.) were considered.
- A fixed tilt system was assumed for both sites. Fixed tilt systems are more compact than single-axis tracker systems and have a lower capital expenditure. The modules are mounted at an optimal orientation (South facing).
- The electrical interconnection characteristics were taken from the AEPC Group's reports, which considered a tie-in to a nearby PG&E distribution lines at 12 kV. No transmission line costs were considered as interconnection infrastructure was assumed to be co-located with the transmission lines and at the edge of the PV power plant. The interconnection requirements and methods must be reviewed in detail for project development.

4.5.1 Tesla Portal

Table 4-13 presents the findings for Tesla Portal.

Table 4-13 Tesla Portal Photovoltaic Design and Performance Assumptions

PARAMETER	PREVIOUS ASSUMPTION	UPDATED ASSUMPTION
Available Area (acre)	16.5	8
Acre per MWac	2.4	5.2
Module Type	Mono-crystalline (210 W)	Poly-crystalline (300 W)
Mounting Type	Fixed tilt (angle not reported)	Fixed tilt – 27 degrees
TMY - GHI (W/m^2)	Not Reported	1,893
PV System Size (kWac)	5,500	1,600
AC Capacity Factor (percent)	Not Reported	24.8
Energy Yield (kWh/kWp)	Not Reported	1,691
Production (kWh/yr)	Not Reported	3,470,142
Capital Cost (2013$)	57,100,000	5,472,530
Capital Cost ($/Wp)	8.00	2.67
Capital Cost ($/Wac)	10.38	3.42

Black & Veatch notes that AEPC Group's assumptions of 2.4 acre per MWac are unrealistic. Also, in consultation with SFPUC the available area was reduced from earlier estimates to take into account recent construction activity at Tesla Portal that reduced the available area for PV.

4.5.2 Sunol Valley

Table 4-14 presents the findings for Sunol Valley.

Table 4-14 Sunol Valley Photovoltaic Design and Performance Assumptions

PARAMETER	PREVIOUS ASSUMPTION	UPDATED ASSUMPTION
Available Area (acre)	100	No Change
Acre per MWac	2.5	5.25
Module Type	Mono-crystalline (210 W)	Poly-crystalline (300 W)
Mounting Type	Fixed tilt (angle not reported)	Fixed tilt – 27 degrees
TMY - GHI (W/m^2)	Not Reported	1,854
PV System Size (kWac)	20,000	19,200
AC Capacity Factor (percent)	Not Reported	23.9
Energy Yield (kWh/kWp)	Not Reported	1,631
Production (kWh/yr)	Not Reported	40,162,953
Capital Cost (2013$)	207,800,000	47,884,188
Capital Cost ($/Wp)	8.00	2.28
Capital Cost ($/Wac)	10.39	2.93

Black & Veatch notes that AEPC Group's assumptions of 2.5 acre per MWac are unrealistic.

4.5.3 Warnerville

Unlike the other two locations, the SFPUC does not own the land that hosts the Warnerville Switchyard, but may be able to obtain long-term leases for project development. The Warnerville Switchyard is located at 10501 Warnerville Rd, Oakdale, CA 95361 and is surrounded primarily by agricultural land. The site is relatively flat and could be suitable for the development of a solar PV facility, possibly more so than Sunol or Tesla due to the favorable topography. A site assessment was not performed for this study but may be considered in future updates.

4.6 COST AND PERFORMANCE ESTIMATES FOR OTHER IN-STATE LOCATIONS

To provide a basis for comparison to in-city costs, several potential project locations were selected in California. Black & Veatch developed two typical, conceptual designs for utility-scale photovoltaic installations: fixed tilt and tracking. Both designs were modeled at each of three representative project locations.

4.6.1 System Parameters

To best represent all commercial options for utility-scale solar, Black & Veatch developed system designs for both fixed tilt and tracking photovoltaic systems. Both systems are based on polycrystalline modules and are typical of the current state of utility-scale design.

Table 4-15 Fixed Tilt Design Assumptions for Statewide Projects

PARAMETER	VALUE	NOTES
Module	300 Watt polycrystalline	Generic 72-cell module
Inverter	500 kW	Paired into 1MW blocks
Mounting Type	Fixed racks	Oriented two high in portrait
Mounting Orientation	25 degree tilt; facing due south	
Mounting Spacing	15 ft. clear row spacing	
PV System Size (MWac)	20 MW	Sum of inverter nameplate
PV System Size (MWdc)	27.7 MW	Sum of module rating

Table 4-16 Tracking Design Assumptions for Statewide Projects

PARAMETER	VALUE	NOTES
Module	300 Watt polycrystalline	Generic 72-cell module
Inverter	500 kW	Paired into 1 MW blocks
Mounting Type	Single Axis Tracking	Oriented one high in portrait
Mounting Orientation	Rows oriented N-S, tracking E-W	
Ground Coverage Ratio	37 percent	
PV System Size (MWac)	20 MW	Sum of inverter nameplate
PV System Size (MWdc)	25.9 MW	Sum of module rating

4.6.2 System Costs

Black & Veatch developed cost estimates for the construction and operation of the conceptual utility-scale plants in California. Capital costs are for the overnight construction of the facility in the second half of 2013 by a private developer using typical industry specifications. Specific location and interconnection details were not developed for the conceptual PV systems because the siting of the systems is flexible to make best use of available transmission. For this reason, the capital costs include the cost of a generic transmission interconnection using a 34.5kV onsite substation with no significant gen-tie required. It is assumed that this cost is representative of opportunities in the vicinity of the selected project locations.

Table 4-17 System Costs for Statewide Projects

	CAPITAL COST (2013$/KWAC)	FIXED ANNUAL COST (2013$/KWAC/YR)
Fixed Tilt Design	$3,289	$29
Tracking Design	$3,536	$32
Note: O&M costs exclude property taxes, but include land lease payments and insurance.		

4.6.3 Project Locations

For the purposes of modeling system performance, Black & Veatch selected project locations which are representative of utility-scale projects in California. The selected locations satisfy the following requirements.

- Has available transmission capacity based on Black & Veatch's analysis of major substations.
- Has demonstrated commercial interest based on Black & Veatch market experience, PPA contract information, and interconnection requests
- Is located in a region with a significant amount of developable land, based on GIS analysis of terrain, environmental concerns, farmland protection, military land, and other concerns.

Project locations were chosen to be the sites of major transmission substations. Black & Veatch does not suggest that development at the substation is likely, but notes that the solar resource at the substation site can represent the resource for projects in the region. To represent the diversity of system performance available in California, one substation was chosen from each of California's three Investor Owned Utilities. This provided good representation of the spectrum of climates which are being developed in California.

Table 4-18 Statewide Project Locations

SUBSTATION / LOCATION	COUNTY	GLOBAL HORIZONTAL IRRADIANCE (KWH/SQM/DAY)	NOTES
Midway (Path 15)	Kern	5.45	Southern Central Valley
Windhub	Kern	5.80	Tehachapi
Imperial Valley	Imperial	5.56	Imperial Valley / Sunrise

4.6.4 System Performance

Black & Veatch modeled the performance of systems matching our conceptual designs at each of the selected locations. The performance model was based on the National Renewable Energy Laboratory's Solar Advisor Model along with data from the National Solar Radiation Database. The model was based on the design parameters described above as well as standard industry assumptions.

Table 4-19 Statewide Fixed Tilt System Performance

LOCATION	AC CAPACITY FACTOR	ANNUAL GENERATION
Midway	26.7 percent	46.9 MWh
Windhub	29.2 percent	51.2 MWh
Imperial Valley	28.2 percent	49.4 MWh

Table 4-20 Statewide Single Axis Tracking System Performance

LOCATION	AC CAPACITY FACTOR	ANNUAL GENERATION
Midway	31.6 percent	55.4 MWh
Windhub	35.9 percent	62.8 MWh
Imperial Valley	33.4 percent	58.5 MWh

4.7 COMPARISON BETWEEN LOCATIONS

This section summarizes cost and performance parameters estimated to in-city, up country, and statewide project locations.

Table 4-21 In-City Photovoltaic Costs and Performance Comparison

LOCATION	NET PLANT CAPACITY (KWAC)	AC CAPACITY FACTOR (PERCENT)	CAPITAL COST ($/KWAC)	O&M COST ($/KW-YR)
Hunters Point	2.5	20.3	7365	45
Hunters Point	5	20.3	7365	45
Marina Middle School	50	21.1	7245	27
Thurgood Marshall	200	22.3	6165	27
College Hill Reservoir	895	20.8	6000	27
Summit Reservoir	664	19.7	6075	27
Stanford Heights Reservoir	704	19.6	6060	27
Sutro Reservoir	2,010	19.7	5550	27
University Reservoir	2,883	20.8	5385	27
Pulgas Reservoir	2,650	21.5	5385	27

Notes:

- **Costs reflect all construction and development requirements for new construction with few site improvements. They do not reflect any incentives or tax credits**
- **Pulgas Balancing Reservoir is located outside of SF City limits**
- **O&M costs exclude property taxes and land lease payments, but include insurance**

Table 4-22 Upcountry Photovoltaic Costs and Performance Comparison

LOCATION	NET PLANT CAPACITY (KWAC)	AC CAPACITY FACTOR (PERCENT)	CAPITAL COST ($/KWAC)	O&M COST ($/KW-YR)
Sunol	19,200	23.9	2.930	22
Tesla	1,600	24.8	3,420	22

Notes:
- **Reflects costs of new generation using typical industry development assumptions**
- **Capital costs cover all construction and development requirements. They do not reflect any incentives or tax credits**
- **O&M costs exclude property taxes and land lease payments, but include insurance**

Table 4-23 Statewide Photovoltaic Costs and Performance Comparison

LOCATION	NET PLANT CAPACITY (KWAC)	AC CAPACITY FACTOR (PERCENT)	CAPITAL COST ($/KWAC)	O&M COST ($/KW-YR)
Midway Fixed Tilt	20,000	26.7	3,289	29
Midway Tracking	20,000	31.6	3,536	32
Windhub Fixed Tilt	20,000	29.2	3,289	29
Windhub Tracking	20,000	35.9	3,536	32
Imperial Valley Fixed Tilt	20,000	28.2	3,289	29
Imperial Valley Tracking	20,000	33.4	3,536	32

Notes:
- **Reflects costs of new generation using typical industry development assumptions at sites with few barriers to construction**
- **Capital costs cover all construction and development requirements. They do not reflect any incentives or tax credits**
- **O&M costs exclude property taxes and land lease payments, but include insurance**

4.8 DEVELOPMENT CHALLENGES

Solar PV projects face many types of development challenges. Those common to any type of development include technical risks, such as the adequacy of the power grid to transmit the power, the distance from transmission interconnection points, schedule delays, development cost overruns, and power plant performance. Regulatory and legal risks also apply, such as potential environmental impacts, land use and zoning constraints, ownership and access issues, permitting, regulatory approval of PPA terms, and availability of tax incentives. Commercial risks common to many types of power plants include the ability to negotiate a commercially viable PPA price, the creditworthiness of the off-taker, macroeconomic risks such as growth rates, inflation, and power demand, as well as the ability to attract equity investment and obtain project finance. Some or all of these are usually present in a solar project.

Solar resource uncertainty is a risk to solar projects. The solar resource is more predictable and stable than other renewable resources, but it is still specific to the project site. Good data on the site-specific resource may not be easily available, and expected interannual variability can mean that a long data history is needed to achieve confidence in the long-term performance of the project.

There are a few risks associated with the suitability of the project site. Shading of the solar project is a risk to project production. For a ground mounted site, this may be trees that cannot be removed or features on the horizon. For a roof-mounted site, this could be nearby structures, equipment, or architectural features.

For a ground mounted site, the topography or drainage could be too demanding for economic solar use. Solar projects typically occupy large areas of land, but cannot bear the cost of significant civil works. Further, it can be hard to permit a project unless land features are preserved, which can fragment the project site. A fragmented project site can be prohibitively complex to develop.

For a rooftop site, there is risk associated with the condition of the roof. The structure of the roof must be proven adequate for the additional loads associated with the solar system. These include wind loads in addition to the weight of the system. Also the lifetime of the solar system can extend beyond the remaining life of the roofing material, which can add additional lifetime cost to the project.

5.0 Wind Resource Assessment

A selection of project locations and sizes were considered in this assessment to develop the technical basis for estimating the cost and performance for wind resources that are typical of the types of opportunities available to the SFPUC.

5.1 TECHNOLOGY DESCRIPTION

Wind energy technology has made major advancements since the production of wind turbines in the early 1980's. Three decades of technological progress has resulted in today's wind turbines being a cutting edge technology. A modern, single wind turbine has the ability to produce nearly two hundred times more electricity annually and at less than half the cost per kilowatt-hour than its equivalent twenty years ago. The wind power sector now includes some of the world's largest energy companies.

A wind farm typically consists of many individual wind turbines spread across a large area. The overall shape and size of a wind farm varies with each individual project, but they are typically arranged in several rows or cluster of turbines. Wind resource, terrain, land cover, land ownership, residences, environmental restrictions, and existing road networks all influence the final configuration of a wind project. Although a large amount of land is required for development and construction of a wind project, most of the land is undisturbed by the project and can remain in use for its original purpose. This makes large wind projects highly compatible with agricultural activities, with some exceptions such as aerial application of pesticides and fertilizers.

Wind turbines generally are mounted to relatively shallow octagonal inverted tee spread footing foundations, typically between 50 and 60 feet across, with anchor bolts embedded into a smaller circular pedestal 10-15 feet across, to which the turbine tower is mounted. Depending on the specific configuration of the wind turbine generators, a small transformer may be mounted adjacent to the turbine base, inside the base of the turbine tower, or in the turbine nacelle. This transformer converts power from the typical 600 V generating voltage to the 35 kV class collection system voltage (typically 34.5 kV in the US).

A central collection substation is generally built within the overall footprint of a wind farm. This collection substation includes the main power transformer, which converts the collection system voltage to the voltage of the interconnection transmission line. From this collection substation wind farm is interconnected to the grid. The interconnection point may be adjacent to the substation if it is built along the interconnecting transmission line, or the project may construct a new transmission line and interconnection switchyard adjacent to the interconnecting transmission line.

Although each turbine is fully capable of autonomous operation, all turbines are linked together to a project control system (SCADA). The central SCADA system can monitor and control the project as needed, included recording of all project operating data and implementation of curtailment controls as needed.

In addition to the turbines, access roads, collection system, and substation, wind projects typically include an operations and maintenance (O&M) facility. This facility is often a pre-engineered building and warehouse, with offices, conference rooms, restrooms and showers, storage, and warehousing.

5.2 RESOURCE AVAILABILITY

This sections reviews available wind resources in San Francisco and California.

5.2.1 In-City

Black & Veatch reviewed the findings of the Public Interest Energy Research (PIER) City and County of San Francisco Wind Resource Assessment Project[10] for estimating in-city performance. The PIER study determined that the majority of sites in the in-city area were not economically feasible for a 10 kilowatt machine installed at a 10 meter hub-height. This finding is in line with Black & Veatch's experience regarding small, urban area installations. Generally, wind regimes in urban areas are adversely impacted by local obstructions, and the costs can be very high. This is in part due to the inability to apply economies of scale for the project, resulting in higher manufacturing costs per-turbine, and engineering, mobilization, and demobilization costs that are relatively higher on a per-kilowatt basis. Due to these challenges, there is also a limited amount of data for comparison and study regarding small, urban projects.

Black & Veatch has performed a high-level review of the potential for a single commercially sized turbine at the Oceanside Waste Water Treatment Plant. An in-depth assessment of in-city potential was not performed for this study. An overview of the 100 meter wind speed potential in the San Francisco region is shown below in Figure 5-1 based on AWS Truepower data.

[10] Available at http://www.energy.ca.gov/pier/project_reports/500-04-066.html

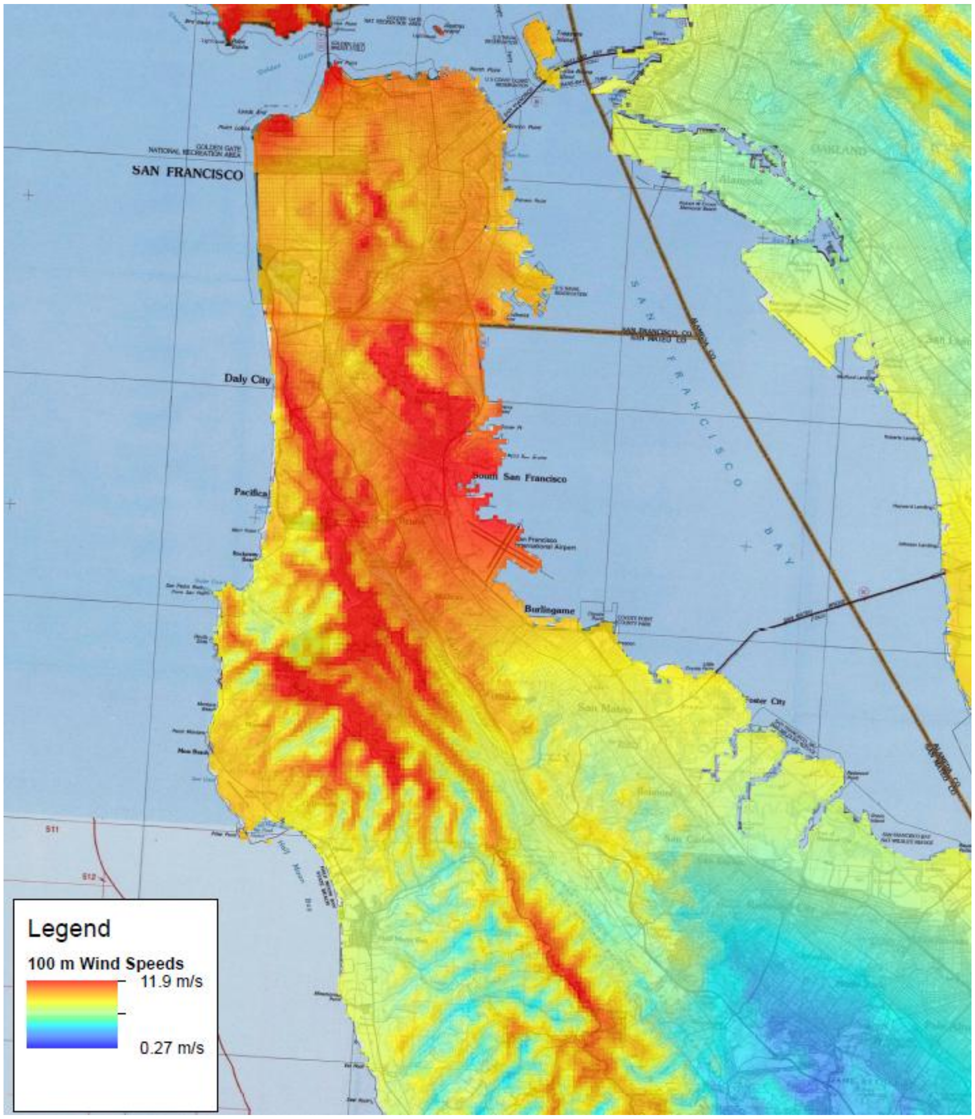

Figure 5-1 100 Meter Wind Speeds in the San Francisco Region

5.2.2 Statewide

SFPUC is interested in the wind development potential of several sites on a state-wide level. The size of these locations varies from a possible site capacity of 6 megawatts to 30 megawatts. The majority of these locations are east of the San Francisco area. This includes proposed projects at the Sunol and Tesla facilities, a possible project in the Montezuma Hills based on a proposal received by the SFPUC, and a potential re-powering site in the Altamont Pass.

In addition to the sites currently under consideration by SFPUC, Black & Veatch performed a high-level assessment of the available wind resource and project development potential across the state of California to identify other potential sites for development. Not all the land in California can be considered available, so “exclusions” for excluding land that may not be suitable for wind development were developed for this study. These exclusions include urban areas, national parks, wetlands, military no-fly zones, and other sensitive areas. Areas with wind speeds lower than 5.5

meters per second were also excluded, as projects with wind speeds lower than 5.5 meters per second are unlikely to be economically feasible. These exclusions ensure that the analysis uses realistic assumptions about where wind power can be developed.

Black & Veatch selected several possible candidate wind projects from the available land which had high wind speeds and low estimated balance of plant (BOP)/erection and turbine costs. Transmission costs were not considered for the initial selection, but were reviewed for each of the identified candidates. Based on this review, the candidates were narrowed to three projects, which are representative sites for low, moderate, and high transmission costs, as seen in Newberry Springs, Walnut Grove, and Leona Valley, respectively.

The estimated wind speed regime for California and the eight projects investigated in this report is shown below in Figure 5-2, based on AWS Truepower data.

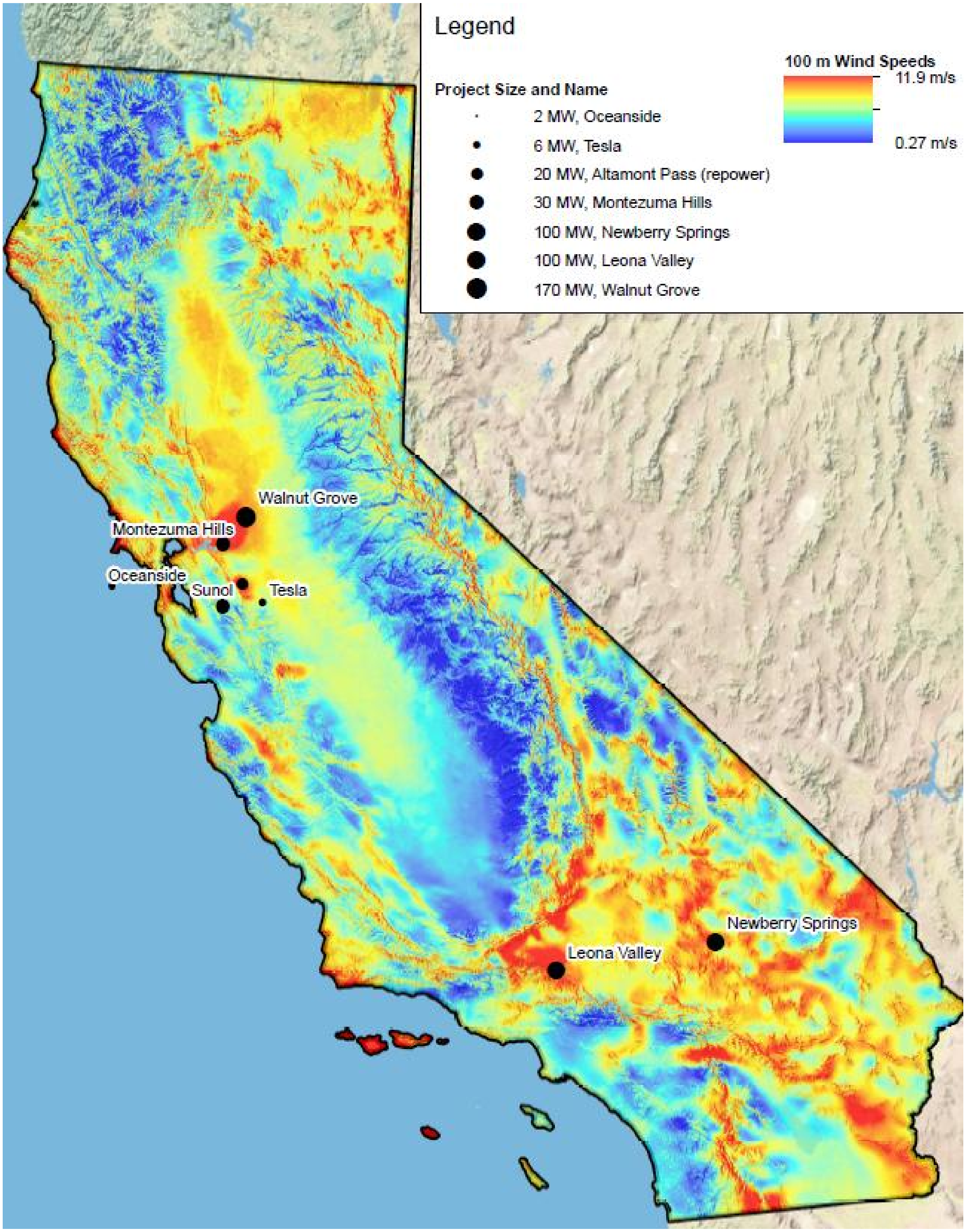

Figure 5-2 100 Meter Wind Speeds in California

5.2.3 Locational Analysis

This section provides an overview of what information was used and how projects were located for this study.

5.2.3.1 Wind Resource

Measured data was provided by the client at the Sunol and Tesla sites. Approximately six years of data, from February 2007 to April 2013, were available from the Sunol site. At the Tesla location, 7 months of data were available. The exact heights and coordinates for each data resource were not known, but are understood to be rooftop or other facility-mounted equipment. Since the Tesla site had only half a year of data, Black & Veatch used the long-term reference data at the airport to obtain a rough estimation of the site's wind characteristics for the entire year. Black & Veatch obtained 10 years of wind speed data from the nearest available airport that had a data record dating back to 2009, the Metropolitan Airport in Stockton.

A study was performed by AWS Truepower in 2007 for the California Energy Commission's Intermittency Analysis Project. AWS Truepower used their Mesoscale Atmospheric Simulation System (MASS) to predict wind speeds at several heights above ground. The atmospheric model output is gridded with a spatial resolution of 2 km. The results of the atmospheric model are then interpolated to a 200 meter grid by AWS Truepower based on local terrain and land cover. The model was run in nested grids for a three year period and had reanalysis, rawinsonde[11] and surface weather data as inputs. This data was utilized by Black & Veatch to characterize the wind speeds throughout California.

The average wind speeds at Sunol and Tesla were compared to the results obtained using the modeled AWS Truepower data. While both resources were in rough agreement at the Sunol site, indicating low wind speeds, the measured Tesla site showed significantly higher wind speeds at the measured height than the AWS Truepower data at 100 meters above ground level. There are several possible explanations for this difference. There may be highly localized wind conditions caused by the local topography that occurs on a scale too small for the model to accurately capture. The AWS Truepower wind model has a resolution of 8 kilometers which may not be fine enough to accurately represent this site. Another explanation is that the placement of the mast may not be suitable for wind collection. The information available indicates that the measurement sensors are installed on top of a structure, perhaps a tank, roughly 20 feet above the ground. Depending on how the equipment was installed, this obstruction may cause speed-up effects. The equipment also might be located in the highest wind speed area, which may not be representative for the site as a whole.

The suitability of the data for this study was evaluated, and Black & Veatch chose to use the modeled results from AWS Truepower to estimate wind speeds at each site. The uncertainty in the measured data at the Tesla site is too great to base this study on. However, it may be worth further

[11] A method of upper-atmosphere meteorological observation conducted by means of a radiosonde tracked by radar.

investigation, with a 60 meter or higher met mast, to verify if the Tesla site does have localized high winds that would otherwise not be correctly estimated in the high-level modeled data.

5.2.3.2 Additional Site Selection

Sites were chosen from the available land after the removal of exclusions based on anticipated production, as well as factors that could impact costs, such as proximity to existing transmission, land ownership, and terrain. Representative sites were chosen to illustrate low, moderate, and high transmission cost scenarios.

The wind speeds expected at each site are summarized below in Table 5-1.

Table 5-1 Comparison of Annual Wind Speeds

SITE	COUNTY	WIND SPEED
SF Oceanside WWTP	San Francisco	5.97 m/s
Sunol	Alameda	4.52 m/s
Tesla	San Joaquin	4.98 m/s
Montezuma Hills	Solano	6.84 m/s
Altamont re-power	Alameda	7.32 m/s
Walnut Grove	Yolo	6.53 m/s
Leona Valley	Los Angeles	6.99 m/s
Newberry Springs	San Bernardino	6.53 m/s

5.3 COST BASIS

The approach for developing capital costs and operations and maintenance costs are outlined in this section. Transmissions costs were assessed as described in Section 3.2.

5.3.1 Base Costs

A variety of components must be considered when estimating costs. Various turbine types and hub heights will require different amounts of raw materials. Taller turbines with larger rotor diameters necessitate more robust foundations and larger cranes for installation. A summary of all the cost categories considered for Class II and III machines is shown below in Table 5-2. The Class II machine was assumed to have an 80 meter hub height, whereas the Class III was examined using a 100 meter hub height.

Table 5-2 Comparison Costs for Class II and III machines

CATEGORY	CLASS II, 80 M HUB HEIGHT ($/KWAC)	CLASS III, 100 M HUB HEIGHT ($/KWAC)
Turbine	1200	1350
BOP/erection	470	515
Owner's Cost	(15 percent Direct Costs)	(15 percent Direct Costs)

5.3.2 Slope Multipliers

The location of a project site can also impact costs. Steep slopes can make it difficult to construct a wind farm, as much of the land must be cut in order to create level surfaces for foundations, roads, and crane pads. To account for the impact of terrain, Black & Veatch applied multipliers to BOP/erection costs based on the average slope of a given area. These multipliers are shown below in Table 5-3.

Table 5-3 Slope Cost Multipliers

SLOPE	MULTIPLIER
Slope < 4	1.0
4 < slope < 8	1.16
8< slope <16	1.22
Slope > 16	1.55

5.3.3 Economies of Scale

Economies of scale allow large projects to reduce costs on a per kilowatt basis, but this effect is lost once projects become too small. Black & Veatch has assumed that a project of 20 megawatts or larger is able to benefit from economies of scale. However, not all the projects under consideration in this report meet that size requirement. Both the Oceanside and Tesla sites are only large enough for one to three turbines, at most about 6 MW of capacity. This causes increases in engineering, mobilization, demobilization, BOP, and owner's costs relative to the total cost of the project. In the 2011 Wind Technologies Market Report published by the U.S. Department of Energy, installed costs are examined by project size, turbine size, and region. The report illustrated that small projects of five megawatts and smaller have a total installed project cost roughly 20 percent higher than larger projects. It also demonstrated that there was little change in project cost in dollars per kilowatt once a project reached 20 megawatts or more. As such, Black & Veatch has assumed that economies of scale apply to any project with rated capacity of 20 megawatts or greater, and has applied a factor of 1.2 to the total costs of any project below 20 megawatts in size.

5.3.4 Operation and Maintenance costs

Operation and Maintenance costs have been divided into fixed and variable segments. The base cost is 35 dollars per kilowatt-year, which includes normal operations, scheduled and unscheduled maintenance, project management, taxes, insurance, and so on. These costs are based on information from the 2011 Wind Technologies Market Report published by the U.S. Department of Energy, along with review of several detailed wind project operating budgets. Land royalty costs are then added to this base cost depending on the type of land the project is expected to be installed on. If the project is built on federally owned Bureau of Land Management (BLM) land, a fixed cost of 4.115 dollars per kilowatt per year is added, based on published BLM land lease rates. If the project is built on Private land, the cost is considered to be variable, reported in dollars per megawatt-hour based on 3.5 percent of gross revenues. This is calculated from estimated generation and typical wind project PPA costs in California. . In general, it is more expensive to construct a project on Private land than it is on BLM land.

5.4 COST AND PERFORMANCE CHARACTERISTICS

Project specific cost and performance characteristics are outlined for SFPUC controlled lands and other statewide locations selected for this study.

5.4.1 SFPUC Controlled Lands (Oceanside, Sunol, Tesla)

Oceanside - The Oceanside site is located at the Oceanside Waste Water Treatment Plant, just south of the San Francisco Zoo, in San Francisco County. The available land is roughly 0.09 square kilometers. A map of the area is shown below in Figure 5-3 .

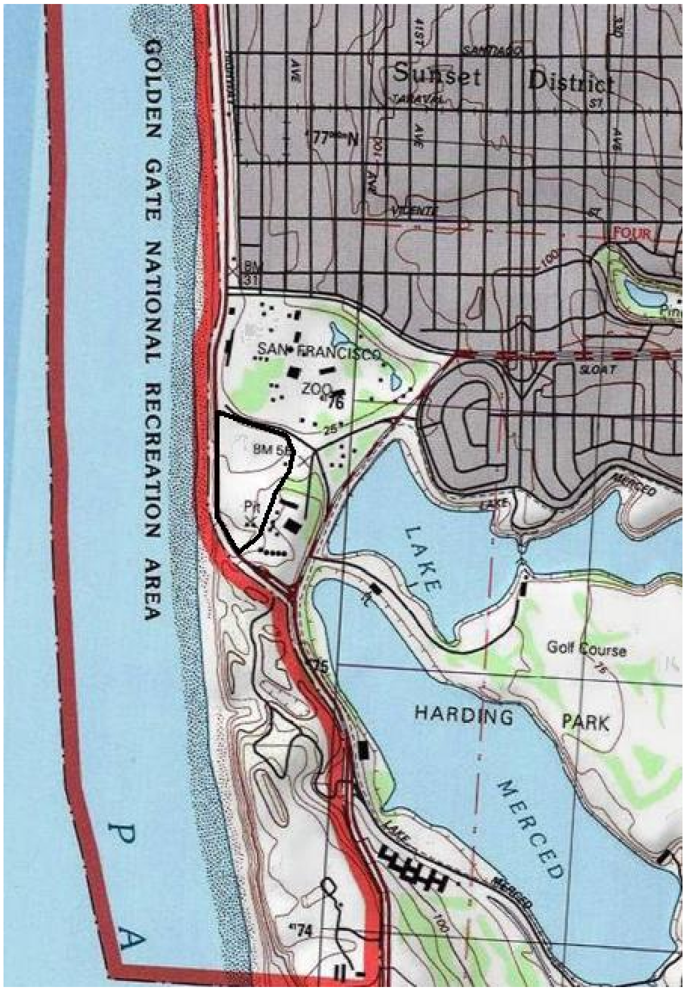

Figure 5-3 Available Land at Oceanside

This region is in a developed, urban area. Neighboring buildings may act as obstacles that will create local disruptions to the wind characteristics of the region. The site is very small, suitable for only a single commercially sized turbine, and setbacks would have to be carefully considered for safety. This site would be anticipated to have 2 MW in nameplate capacity, depending on the turbine selected.

The assumption for interconnection at this site anticipates tie into one of the two12 kV distribution feeders serving the Oceanside plant load. Discussions with SFPUC have indicated that one of the feeders provides redundant capacity and could be used by the wind facility when not needed for back-up power service by the treatment plant.

The PIER study estimated a wind speed of 4.0 m/s at 10 meters above ground level. The AWS Truepower model predicts an average wind speed at the 100 meter level for the two sites near the San Antonio Reservoir is 5.97 m/s. To compare the findings of these two studies, if the 100m wind speed is estimated based on the PIER report findings using the wind shear power law approximation and a standard wind shear component assumption of 1/7, the result is 5.56 m/s, within 10 percent of the AWS Truepower model results.

The PIER study concluded that the wind speed at 10 meters was insufficient to build an economical site with a 10 kW machine. This might not be the case for a commercial turbine designed for low-wind with a hub-height of 100 meters. However, since the project is so small, economies of scale do not apply. Costs per kilowatt at this small project are going to be higher than they would be for a large site with the same wind speed characteristics. Furthermore, the proximity to buildings may impact the wind speeds in ways that cannot be properly represented in the AWS Truepower model. If the client chooses to further investigate development at this location, a detailed wind resource data collection campaign at a minimum measurement height of 60 meters for at least a year would be needed to evaluate the local characteristics of this location.

Using a Class III turbine-type with a 100 meter hub-height, Black & Veatch has estimated the performance and cost expected for a project developed in the combined Oceanside site. Note that the small size of this project increases the costs of the project per-kilowatt as economies of scale no longer apply. This information is summarized in Table 5-4.

Table 5-4 Oceanside Wind Facility Design, Cost, Performance Assumptions

PARAMETER	VALUE
Turbine Model	Class III
Site Capacity (MWac)	2 MW
Height (m)	100 m
CF (percent)	29
Capital Cost ($/kW)	$2,738
Fixed O&M Cost ($/kW-yr)	$60.00
Variable O&M Cost ($/MWh)	$0

5.4.1.1 Sunol

The Sunol site is located roughly seven miles east of Fremont, California, in Alameda county. The available land is roughly 159 square kilometers, although not all of this land is appropriate for wind development. A map of the area is shown below in Figure 5-4 .

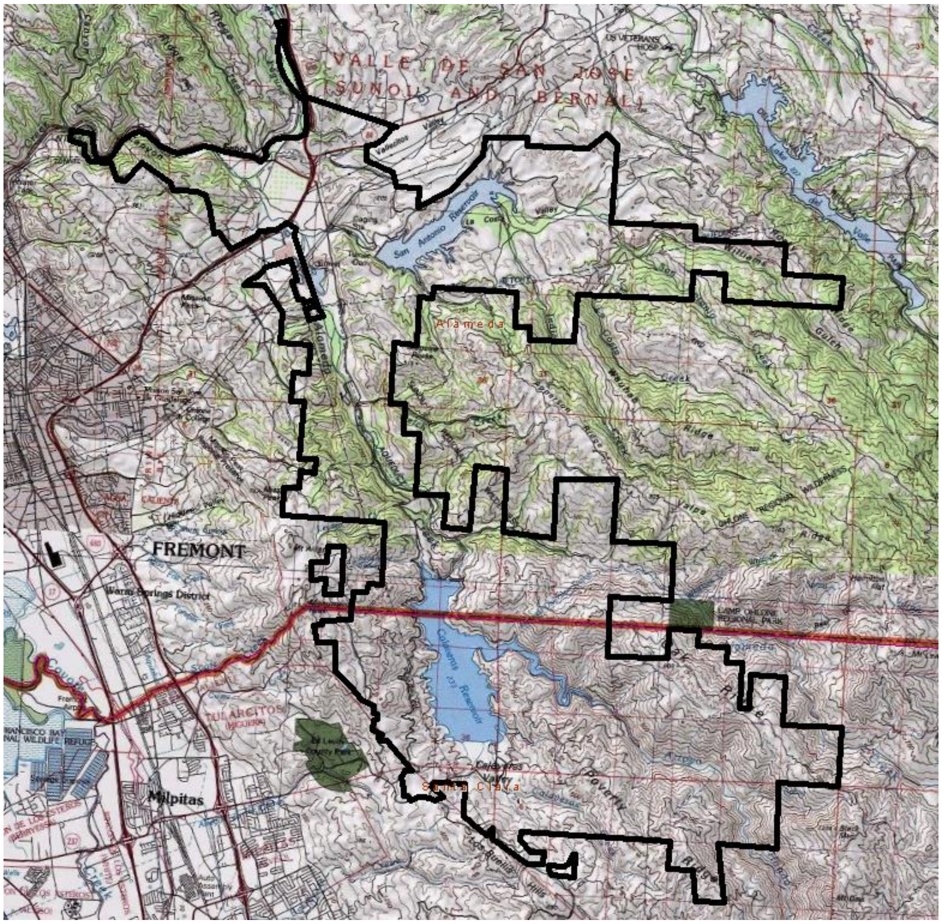

Figure 5-4 Available Land at Sunol

This region has fairly complex terrain. Much of the area is comprised of narrow valleys and reservoirs surrounded by hills and mountains. 30 percent to 50 percent grades are not uncommon, particularly in the southern portion of the available land. The flattest regions of the site are in the northern section, where valleys broaden and are surrounded by more moderate, rolling hills. The valleys are generally flat, and the hills typically have 5 percent to 10 percent grades. Focusing on this northern portion in terrain with less than a 5 percent grade, the most feasible options for the Sunol site are two regions near the San Antonio Reservoir, one to the east and one to the west. These two areas combined are roughly 15 square kilometers, with enough space for approximately 30 MW of capacity, 20 MW to the west and 10 MW to the east. These sites are shown in Figure 5-5 below. Please note that these sites have not been evaluated for environmental set-backs, such as excluding areas where golden eagles might roost. These locations were chosen based only on their feasibility by terrain, for the purpose of this high-level study.

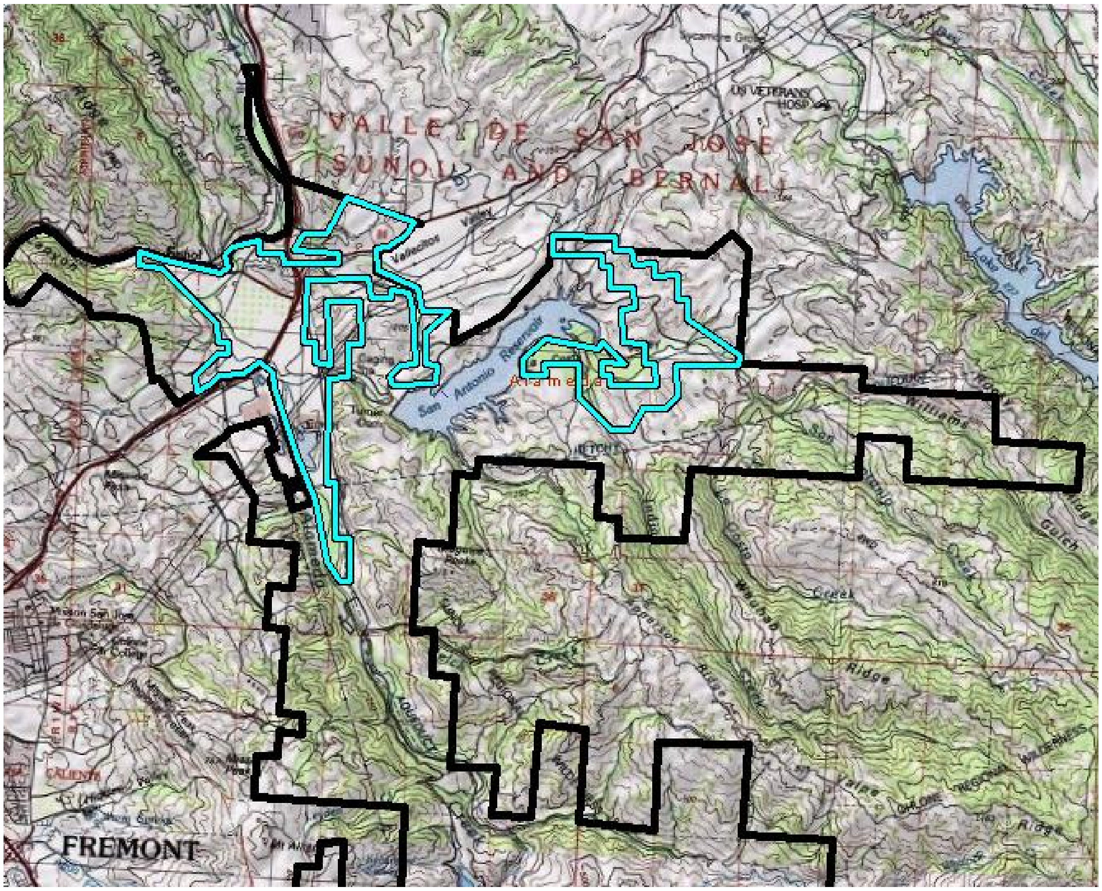

Figure 5-5 Most Feasible Project Options at Sunol

The assumption for interconnection at this site anticipates no generation tie line from the project substation to the Sunol substation. The project substation is assumed to be 69 kV, based on publicly available information, and assumes there is transmission availability and only needs an additional line position.

The wind speeds modeled at this site are low, and unlikely to yield an economically viable project, even with the newest Class III low-wind turbine technologies. The AWS Truepower model predicts an average wind speed at the 100 meter level for the two sites near the San Antonio Reservoir is 4.52 m/s.

Using a Class III turbine-type with a 100 meter hub-height, Black & Veatch has estimated the performance and cost expected for a project developed in the combined Sunol site. This information is summarized in Table 5-5.

Table 5-5 Sunol Wind Facility Design, Cost, Performance Assumptions

PARAMETER	VALUE
Turbine Model	Class III
Site Capacity (MWac)	30 MW
Height (m)	100 m
CF (percent)	15
Capital Cost ($/kW)	$2,577
Fixed O&M Cost ($/kW-yr)	$35.00
Variable O&M Cost ($/MWh)	$0

Tesla - The Tesla site is located roughly six miles southwest of Lyoth, California, in San Joaquin County. The site is adjacent to a Chlorination Station and disinfection facility. The available land is roughly 0.21 square kilometers, although a preference has been expressed for development only within the construction staging area, which is 0.04 square kilometers. A map of the area is shown below in Figure 5-6, with the construction staging area highlighted in red.

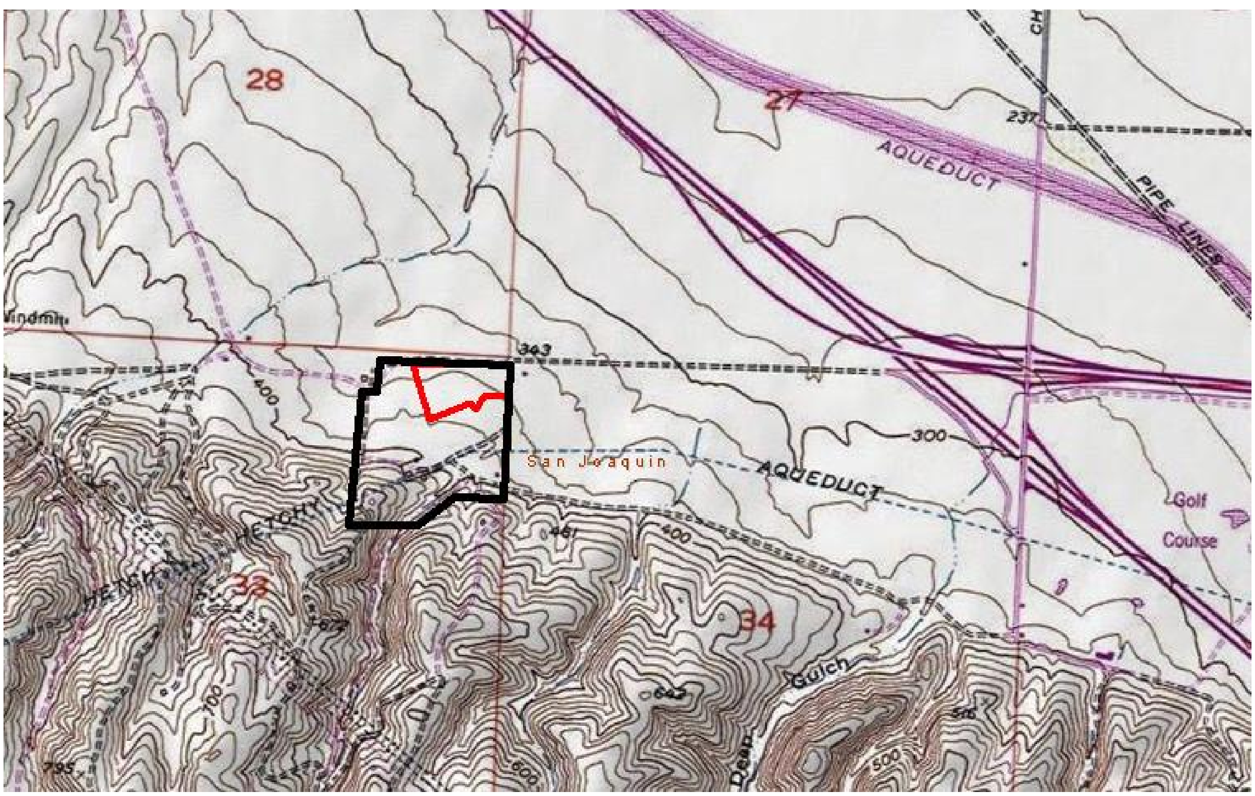

Figure 5-6 Available Land at Tesla

This region has simple, flat terrain in the northern part of the site. The southern portion of the site has hills with 15 percent to 20 percent slopes. Since the region is very small, not many turbines could be installed in this area. If only the construction staging area is utilized, a single turbine could be installed at this location. If the facility as a whole was able to be utilized, two or three turbines might fit on the site, for as much as 6 MW of capacity.

The assumption for interconnection at this site anticipates a local distribution level interconnection to a nearby 12 kV system. Projects of this size are generally uneconomical if additional interconnection infrastructure is required.

The wind speeds modeled at this site are low, and unlikely to yield an economically viable project, even with the newest Class III low-wind turbine technologies. The AWS Truepower model predicts an average wind speed at the 100 meter level for the site to be 4.98 m/s.

Using a Class III turbine-type with a 100 meter hub-height, Black & Veatch has estimated the performance and cost expected for a project developed in the Tesla site. Note that the small size of this project increases the costs of the project per-kilowatt as economies of scale no longer apply. This information is summarized in Table 5-6.

Table 5-6 Tesla Wind Facility Design, Cost, Performance Assumptions

PARAMETER	VALUE
Turbine Model	Class III
Site Capacity (MWac)	6 MW
Height (m)	100 m
CF (percent)	20
Capital Cost ($/kW)	$2,820
Fixed O&M Cost ($/kW-yr)	$35.00
Variable O&M Cost ($/MWh)	$0

5.4.2 Statewide Projects

Montezuma Hills - The Montezuma Hills site is located roughly one mile southwest of Birds Landing, California, in Solano County. The layout and site boundaries were suggested in the proposed Montezuma Zephyr Wind Project presented by Montezuma Wetlands, LLC. The available land is roughly 14.2 square kilometers. Based on discussions with local developers and operators, Black & Veatch believes that it is unlikely this project would be viable due to environmental concerns. However, there are indications that additional areas to the north of highway 12 may open to development in the future with comparable, if not better, wind speeds. For the purposes of this study, Black & Veatch has focused on the originally proposed site. The results of the cost estimates for this region should be roughly comparable to a similar project that could be installed to the north. A map of the area is shown below in Figure 5-7.

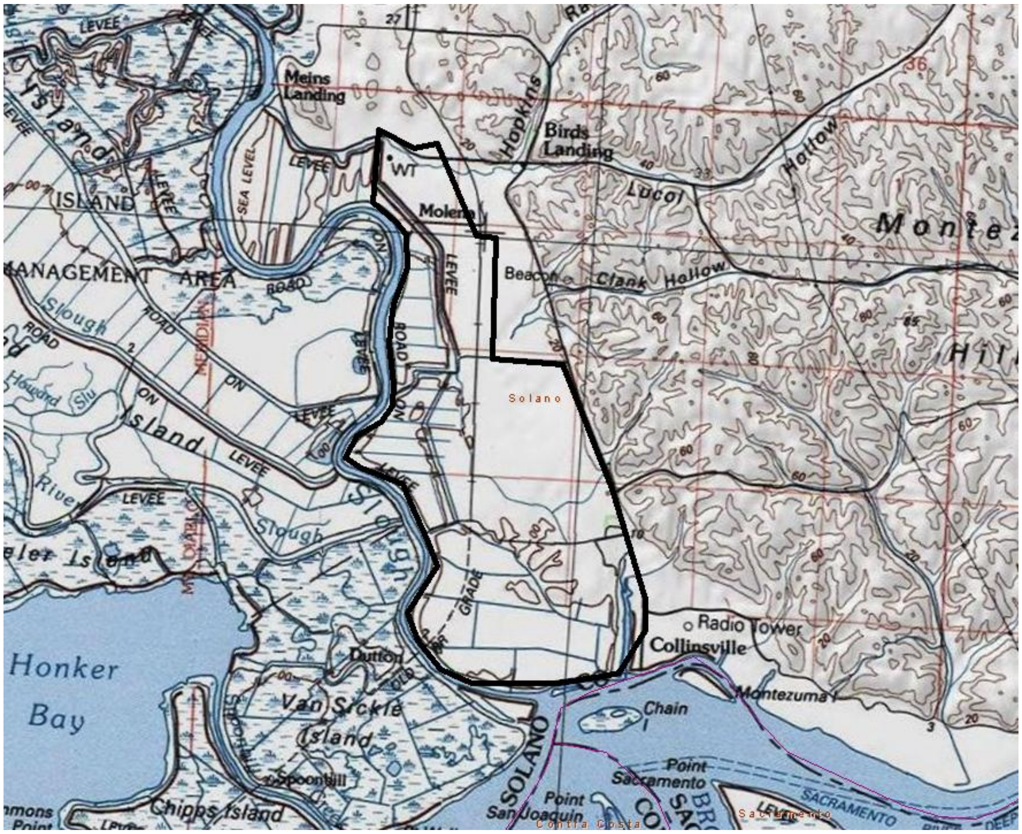

Figure 5-7 Available Land at Montezuma Hills

This region has simple, flat terrain. Using a turbine spacing typically seen in most projects across the nation, roughly three rotor diameters by eight rotor diameters, this site would be suitable for over 30 MW of capacity. However, given the strong winds and unidirectional wind typical for this region, it is common for turbine spacing in Montezuma Hills projects to be much narrower, as little as 1.6 rotor diameters by 6 rotor diameters. If this narrower spacing is used, as in the Montezuma Zephyr Wind Project proposal, this site could contain as much as 100 MW of capacity.

The assumption for interconnection at this site anticipates no generation tie line from the project substation to the Montezuma Hills substation. The project substation is assumed to be 230 kV, based on publicly available information, and assumes there is transmission availability and only needs an additional line position.

The wind speeds modeled at this site are strong. The Zephyr Wind Project proposal indicated an estimated mean wind speed of 6.7 meters per second at the 90 meter level, although it is unclear if this estimate is representative of the long-term wind characteristics. The AWS Truepower model predicts an average wind speed at the 100 meter level for the site to be 7.04 m/s. This is in the upper range of wind speed limits for a Class III machine, and Class II machines are typical for this area. As such, the Class II turbine model with an 80 meter hub-height was considered more appropriate for this site. The AWS Truepower model predicts an average wind speed at the 80 meter level for the site to be 6.84 m/s.

Using a Class II turbine-type with an 80 meter hub-height, Black & Veatch has estimated the performance and cost expected for a project developed in the Montezuma Hills site. This information is summarized in Table 5-7.

Table 5-7 Montezuma Hills Wind Facility Design, Cost, Performance Assumptions

PARAMETER	VALUE
Turbine Model	Class II
Site Capacity (MWac)	100 MW
Height (m)	80 m
CF (percent)	31
Capital Cost ($/kW)	$2,043
Fixed O&M Cost ($/kW-yr)	$35.00
Variable O&M Cost ($/MWh)	$2.66

Altamont (repower) - The Altamont repower site is located within existing developed areas near Bethany Reservoir roughly eight miles northeast of Livermore, California, in Alameda county. Much of this area is owned by NextEra, and is currently part of a repowering effort. However, several regions remain that have no current repower plans. Black & Veatch selected a general area from these locations that included multiple existing projects as a representative site. The available land is roughly 9.9 square kilometers. A map of the area is shown below in Figure 5-8.

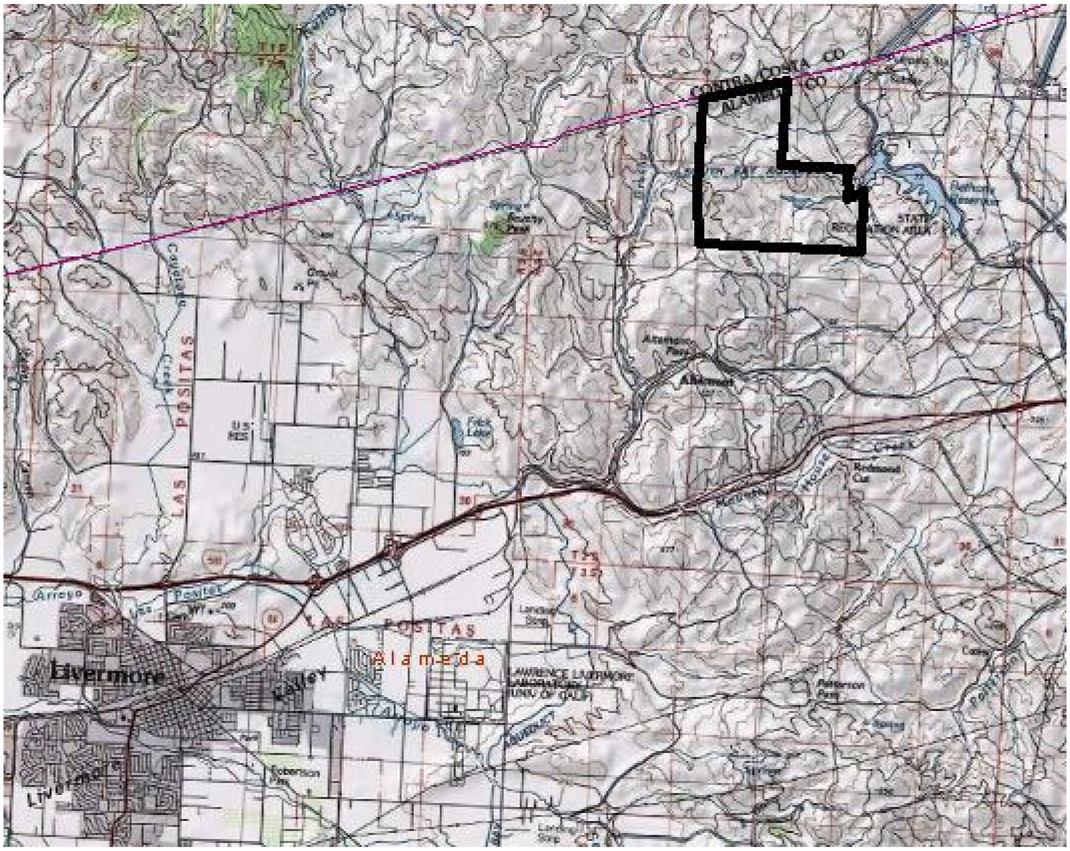

Figure 5-8 Representative Area at Altamont

This region has complex terrain, comprised of rolling hills with slopes ranging from 8 percent to 25 percent gradients. Using a turbine spacing typically seen in most projects across the nation, roughly three rotor diameters by eight rotor diameters, this site would be suitable for approximately 20 MW of capacity.

The assumption for interconnection at this site anticipates no generation tie line from the project substation to the Altamont substation. The project substation is assumed to be 69 kV, based on publicly available information, and assumes there is transmission availability and only needs an additional line position.

The wind speeds modeled at this site are strong. The AWS Truepower model predicts an average wind speed at the 100 meter level for the site to be 7.32 m/s. This is in the upper range of wind speed limits for a Class III machine, and Class II machines are typical for this area. As such, the Class II turbine model with an 80 meter hub-height was considered more appropriate for this site. The AWS Truepower model predicts an average wind speed at the 80 meter level for the site to be 7.28 m/s.

Using a Class II turbine-type with an 80 meter hub-height, Black & Veatch has estimated the performance and cost expected for a project developed in the Altamont site. This information is summarized in Table 5-8.

Table 5-8 Altamont Wind Facility Design, Cost, Performance Assumptions

PARAMETER	VALUE
Turbine Model	Class II
Site Capacity (MWac)	20 MW
Height (m)	80 m
CF (percent)	34
Capital Cost ($/kW)	$2,349
Fixed O&M Cost ($/kW-yr)	$35.00
Variable O&M Cost ($/MWh)	$2.68

Walnut Grove (Low) - The Walnut Grove site is located roughly nine miles northwest of Walnut Grove, California, in Yolo County. The available land is split by a man-made water-way called the Sacramento River Deep Water Ship Channel. The available land is approximately 71 square kilometers. A map of the area is shown below in Figure 5-9.

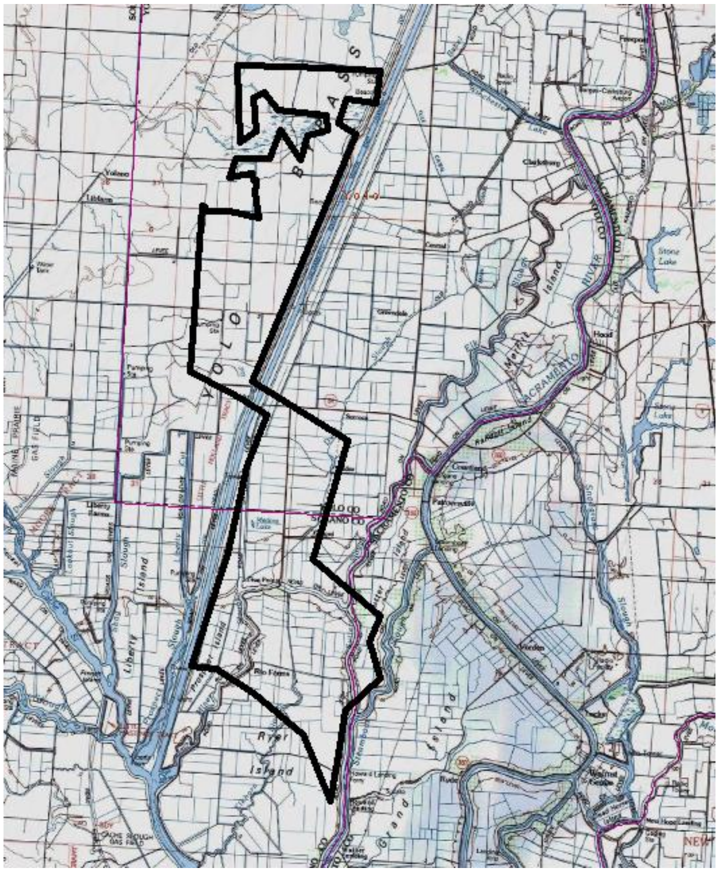

Figure 5-9 Available Land at Walnut Grove

This region has simple, flat terrain, comprised of predominantly cultivated land. Using a turbine spacing typically seen in most projects across the nation, roughly three rotor diameters by eight rotor diameters, this site would be suitable for up to 170 MW of capacity, or two smaller projects of up to 85 MW on either side of the channel.

The assumption for interconnection at this site anticipates a one-mile generation tie line to the PG&E Grand Island substation. The project substation is assumed to be 115 kV, based on publicly availability, and assumes there is transmission availability and only needs an additional line position.

The wind speeds modeled at this site are fairly strong. The AWS Truepower model predicts an average wind speed at the 100 meter level for the site to be 6.53 m/s. While in the upper range of wind speed limits, this is still an acceptable wind speed for a Class III machine.

Using a Class III turbine-type with a 100 meter hub-height, Black & Veatch has estimated the performance and cost expected for a project developed in the Walnut Grove site. This information is summarized in Table 5-9.

Table 5-9 Walnut Grove Wind Facility Design, Cost, Performance Assumptions

PARAMETER	VALUE
Turbine Model	Class III
Site Capacity (MWac)	170 MW
Height (m)	100 m
CF (percent)	34
Capital Cost ($/kW)	$2,244
Fixed O&M Cost ($/kW-yr)	35.00
Variable O&M Cost ($/MWh)	2.70

Leona Valley (Moderate) - The Leona Valley site is located in the area surrounding Leona Valley, California, in Los Angeles county. The available land is on either side of and along Portal Ridge. The available land is approximately 101.5 square kilometers. A map of the area is shown below in Figure 5-10.

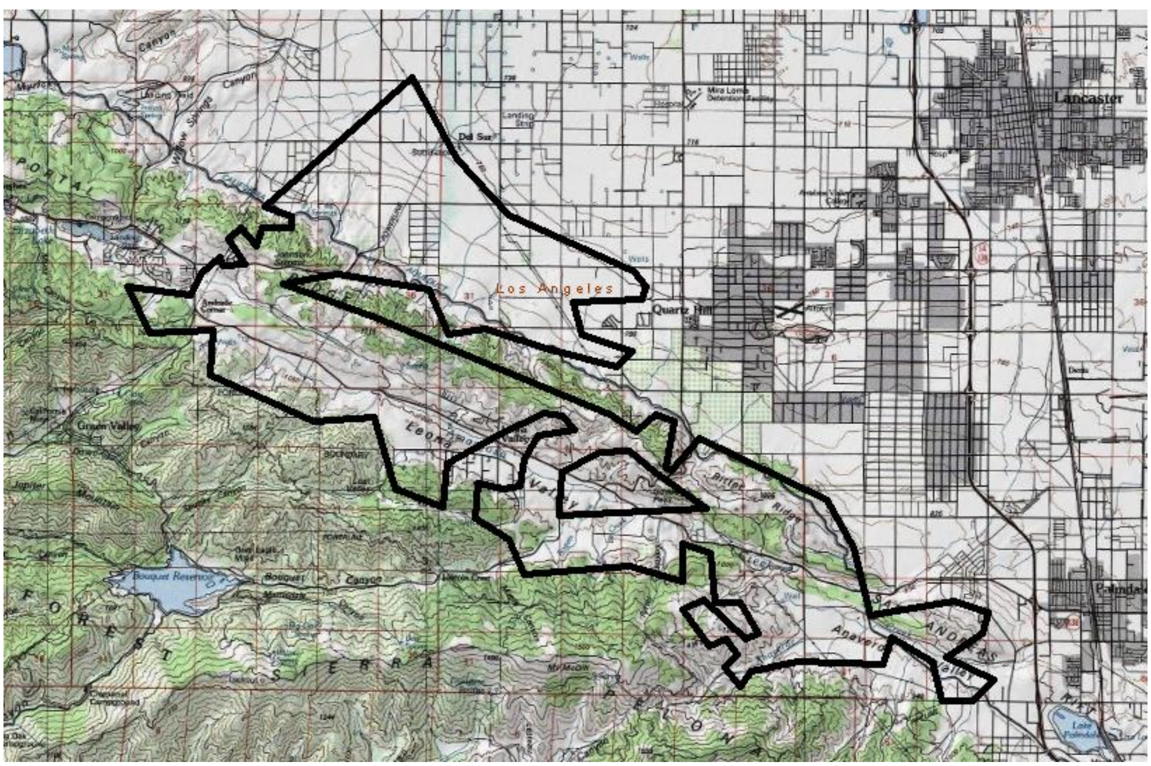

Figure 5-10 Available Land at Leona Valley

This region contains both simple and complex terrain. The portion north of Portal Ridge is flat, open plains. Within the Leona Valley are moderately rolling hills with three percent to eight percent grades. The ridge itself has 20 percent to 35 percent grades. Using a turbine spacing typically seen in most projects across the nation, roughly three rotor diameters by eight rotor diameters, this site could contain over 200 MW of capacity. If only the northern plain was considered, that region could support roughly 70 MW of production, while the Leona Valley could fit approximately 50 MW of capacity. For this assessment a 100 MW project was characterized.

The assumption for interconnection at this site anticipates a 23-mile generation tie line to the SCE Windhub substation. The project substation is assumed to be 230 kV, based on publicly availability, and assumes there is transmission availability and only needs an additional line position.

The wind speeds modeled at this site are strong. The AWS Truepower model predicts an average wind speed at the 100 meter level for the site to be 6.99 m/s. While in the upper range of wind speed limits, this is still an acceptable wind speed for a Class III machine.

Using a Class III turbine-type with a 100 meter hub-height, Black & Veatch has estimated the performance and cost expected for a project developed in the Leona Valley site. This information is summarized in Table 5-10.

Table 5-10 Leona Valley Wind Facility Design, Cost, Performance Assumptions

PARAMETER	VALUE
Turbine Model	Class III
Site Capacity (MWac)	100 MW
Height (m)	100 m
CF (percent)	37
Capital Cost ($/kW)	$2,649
Fixed O&M Cost ($/kW-yr)	$35.00
Variable O&M Cost ($/MWh)	$2.62

Newberry Springs (High) - The Newberry Springs site is located two miles northeast of Newberry Springs, California, across interstate 40 in San Bernardino County. The available land is approximately 46 square kilometers. A map of the area is shown below in Figure 5-11.

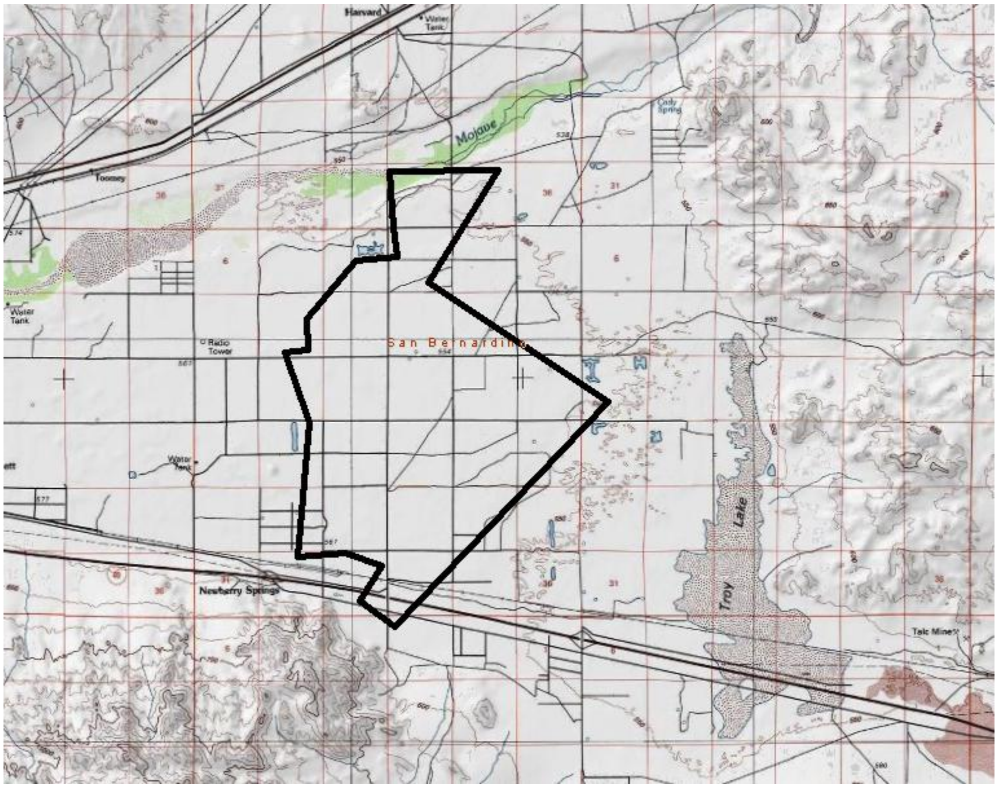

Figure 5-11 Available Land at Newberry Springs

This region is in simple terrain, predominantly flat, open fields interspersed with cultivated land. Using a turbine spacing typically seen in most projects across the nation, roughly three rotor diameters by eight rotor diameters, this site could contain around 100 MW of capacity.

The assumption for interconnection at this site anticipates a 10-mile generation tie line to the SCE Gale substation. The project substation is assumed to be 115 kV, based on publicly availability, and assumes there is transmission availability and only needs an additional line position.

The wind speeds modeled at this site are fairly strong. The AWS Truepower model predicts an average wind speed at the 100 meter level for the site to be 6.53 m/s, acceptable for a Class III machine.

Using a Class III turbine-type with a 100 meter hub-height, Black & Veatch has estimated the performance and cost expected for a project developed in the Newberry Springs site. This information is summarized in Table 5-11.

Table 5-11 Newberry Springs Wind Facility Design, Cost, Performance Assumptions

PARAMETER	VALUE
Turbine Model	Class III
Site Capacity (MWac)	100 MW
Height (m)	100 m
CF (percent)	34
Capital Cost ($/kW)	$2,332
Fixed O&M Cost ($/kW-yr)	35.08
Variable O&M Cost ($/MWh)	2.68

5.4.3 Conclusions

Most projects with a net capacity factor above 25 percent have the potential to be economically feasible, although the costs must be carefully considered in addition to the estimated production for any site. Projects with less than 25 percent capacity factors, such as the Sunol and Tesla sites, may not be economical for wind development. Other technologies, such as solar, might be more profitable for development in these areas. A comparison of the turbine types, capacity factors, and costs for each site is included in Table 5-12.

Table 5-12 Comparison of Wind Design, Cost, Performance Parameters for All Sites

	TURBINE MODEL	CAPACITY (MW AC)	HEIGHT (M)	CF (PERCENT)	CAPITAL COST ($/KW AC)	FIXED O&M COST ($/KW-YR)	VARIABLE O&M COST ($/MWH)
Oceanside	Class III	2	100 m	29	2,738	60	0
Sunol	Class III	30	100 m	15	2,577	35	0
Tesla	Class III	6	100 m	20	2,820	35	0
Montezuma Hills	Class II	100	80 m	31	2,043	35	2.66
Altamont	Class II	20	80 m	34	2,349	35	2.68
Walnut Grove	Class III	170	100 m	34	2,244	35	2.70
Leona Valley	Class III	100	100 m	37	2,649	35	2.62
Newberry Springs	Class III	100	100 m	34	2,332	35	2.68

Notes:

- **Reflects cost of new generation using typical industry development assumptions at sites with few barriers to construction. Further environmental permitting viability must be performed at all sites, especially Oceanside and Altamont.**
- **Capital costs cover all construction and development requirements. They do not reflect any incentives or tax credits**
- **Oceanside and Tesla have no economy of scale advantage due to their size.**

5.5 DEVELOPMENT CHALLENGES

The technical and commercial challenges to wind development are limited. While high wind sites in California are increasingly limited as development continues, good opportunities still exist. Wind is a mature technology, and development costs are well known. Development timelines and requirements are also well understood. Commercial and finance risk exists, but is generally low as well.

The primary challenges to wind development are environmental and permitting. While some of these challenges may rest more on perception than genuine risk they still present a real challenge to wind development. Key risks for wind development include the potential for impacts to birds, both local and migratory, and other wildlife. This is especially true for the identified repowering project in the Altamont Pass, which has well known historical avian issues. High quality environmental studies must be performed, and impacts to other wildlife, including bats and threatened and endangered ground-dwelling animals, must be well studied. Permits on a national, state, and local level must be obtained. Commonly, this includes Federal Aviation Administration review, an endangered species act review, historical preservation and cultural studies, stormwater discharge, highway occupancy, and conditional use permits. Another challenge is the transportation of large components, both to some of the more rugged sites in California and to urban locations. In habited regions, routes must avoid low-hanging electrical lines and narrow turns. In rural areas, roads may require enhancement to bear the weight, or altered to the proper slope and angle of curvature.

Some possible development challenges are specific to the identified potential projects. The Oceanside location is located within a city, relatively close to businesses and dwellings. Turbines in an urban site can cause disturbances due to shadow flicker, noise, or visual skyline disruptions. Careful siting, robust studies, and cooperation with the local community throughout the process are essential. Curtailment during certain times of the day or year may also become necessary to address community concerns. Transportation can present a challenge. In addition to previously noted avian issues, the Altamont Pass project may also be subject to height and size restrictions that could affect using large turbines. The identified project in the Montezuma Hills is located in low-lying land and may have permitting and environmental constraints. Development in other parts of the Montezuma Hills may have increased losses and reduced ability to move power to market because of existing heavy development in the region.

Projects are often dependent on federal tax incentives, which historically have been renewed on a cycle shorter than the average development time for a project, and can lead to uncertainty. Procurement can have long lead time intervals, up to a year or more for wind turbines, and 9-12 months for other major equipment.

Other risks relate to uncertainty about the resource during early phases of the project, notably those related to the following parameters:

- Turbine availability for the first year of operation (typically more problems in this period than for the rest of the installation life-span)
- Long-term wind resource behavior
- Wake losses introduced by new neighboring developments
- Environmental issues that may deteriorate the blade’s surface
- Curtailment due to load or community concerns

6.0 Geothermal Resource Assessment

A selection of project locations and sizes was considered in this assessment to develop the technical basis for estimating costs and performance for geothermal power facilities that are typical of opportunities available to the SFPUC.

6.1 TECHNOLOGY DESCRIPTION

Three main types of facilities are used to generate electricity – direct steam plants, flash steam plants, and binary plants. Direct steam and flash steam plants supply steam from the ground directly to a turbine generator. Direct steam plants are suitable where the geothermal hydro resource is dominated by vapor. Flash steam plants are used when hot water resources above about 190 C are dominated by liquid and must be flashed to produce steam. Steam exiting the steam turbine generator is cooled into liquid form and is typically re-injected into the earth. Binary plants are used when water resource temperatures are lower than about 190 C using a working fluid that is heated to its boiling point in a heat exchanger, where thermal energy is transferred to the working fluid from the hot water resource. Binary systems may also be economical in areas with higher temperature fluid is present that has high scaling potential. In a binary facility, the working fluid and hot water are in separate closed-loop systems. The working fluid vapor is supplied to a turbine generator and is then condensed to be used again while the spent hot water is re-injected into the earth. There are known geothermal resources present in California to support the development of both flash and binary facilities.

Enhanced geothermal systems (EGS) use the presence of geothermal heat in areas with no fluid to produce steam by injecting water into the ground. EGS technology is not yet a commercially proven technology. EGS is therefore not considered in this study.

6.2 RESOURCE AVAILABILITY

Twelve areas with developable geothermal potential have been characterized by Black & Veatch. These areas were previously identified for the RETI project with the help of GeothermEx, a subcontractor to Black & Veatch, through a review of publicly available information. Developable potential for each area was updated for this study to reflect recent project development. These areas are listed in Table 6-1. The megawatt potential identified reflects what is available for new development.

Table 6-1 Geothermal Developable Potential

RESOURCE AREA	TECHNOLOGY	MWAC POTENTIAL	NOTES
Brawley	Binary	160	Sum of Brawley, East Brawley, and South Brawley
East Mesa	Binary	32	Includes Dunes & Glamis
Geysers	Flash	135	Includes Calistoga & Clear Lake [Sulphur Bank]
Heber	Binary	32	Includes Border, Mount Signal, & Superstition Mountain
Honey Lake	Binary	8	
Lake City / Surprise Valley	Binary	32	
Long Valley M-P Leases	Binary	40	
Medicine Lake	Binary	384	
Mt. Shasta	Flash	45	Includes areas around Lassen: Growler & Morgan
Randsburg	Binary	24	
Salton Sea	Binary	1,120	Includes Niland and Westmoreland
Truckhaven	Binary	40	Includes San Felipe Prospect

The approximate location of each of the twelve areas with respect to transmission was identified. Transmission capacity was verified for each location, and estimated interconnection and transmission costs were modeled for each location. Based on the costs and access to transmission for each of the geothermal resource areas, three locations with the lowest interconnection costs and readily available transmission capacity were selected to provide a basis for comparison to other renewable energy technologies considered in this study. For this study 50 MW was selected as the upper limit for project sizes based on economics and recent project development. Typical projects include additional expansion as a future goal but this was not modeled for the current study. Figure 6-1 identifies the locations of the three selected projects:

- Geysers – 50 MW
- Long Valley Mammoth – Pacific leases – 40 MW
- Brawley – 50 MW.

Figure 6-1 California Geothermal Projects

6.3 COST AND PERFORMANCE CHARACTERISTICS

Costs are dependent on many factors. Cost for wells and resource characterization studies are substantial for geothermal projects, making up about half of the overall capital cost. Equipment selection such as turbine size and type, whether heat exchangers are used (e.g. for binary or hybrid facilities), balance of plant costs, and cooling tower design. The costs developed for this report include estimated transmission and interconnection costs. The Geysers cost assumes interconnection to a nearby 230 kV line at Sonoma, Long Valley assumed a 115 kV interconnection, and Brawley interconnects to a 92 kV line. Interconnection costs assume there is transmission availability and there only needs to be an additional line position

O&M costs depend on many factors including the chemical makeup of the feed water and whether it has high or low pH and whether it contains any corrosives or scaling agents. The type of plant is a factor as well. Table 6-2 presents cost and performance values considered for this study.

Table 6-2 Geothermal Project Cost and Performance Parameters

PARAMETER	GEYSERS	LONG VALLEY	BRAWLEY
Plant Type	Flash	Binary	Binary
Capacity (MWac)	50	40	50
Generation MWh/yr	394,200	280,320	350,400
CF (percent)	90	80	80
Capital Cost ($/kW)	4,467	4,823	4,963
O&M Cost	27	34	30

Notes:

- **Reflects cost of new generation using typical industry development assumptions.**
- **Capital costs cover all construction and development requirements. They do not reflect any incentives or tax credits.**
- **The geothermal resource at these locations is well understood; it is assumed that predictions of the heat available will be realized. Less understood resources would have higher costs.**

6.4 DEVELOPMENT CHALLENGES

Geothermal projects face many types of development challenges, some of which are generally common to any type of power plant development and some which are unique to geothermal resource development.

Those common to any type of development include technical risks, such as the adequacy of the power grid to transmit the power, the distance from transmission interconnection points, schedule delays, development cost overruns, and power plant performance. Regulatory and legal risks also apply, such as potential environmental impacts, land use and zoning constraints, ownership and access issues, permitting, regulatory approval of PPA terms, and availability of tax incentives. Commercial risks common to many types of power plants include the ability to negotiate a commercially viable PPA price, the creditworthiness of the off-taker, macroeconomic risks such as growth rates, inflation, and power demand, as well as the ability to attract equity investment and obtain project finance. Some or all of these are usually present in a geothermal project.

However, there are some important risks that are specific to geothermal development. Development costs vary considerably for geothermal power development. Costs for drilling production wells vary considerable because deeper wells cost more. Also the character of the geothermal resource will have an impact on development costs because it influences the type of power plant that is suitable for the site. For example binary power plants can be more expensive per installed kW than flash power plants. Geothermal projects require that almost the entire well field be developed (i.e., drill all the wells, which comprise about half of the total development cost) before any revenue is recognized from power production. Other risks relate to uncertainty about the resource during early phases of the project, notably those related to the following parameters:

- resource size and temperature
- average well productivity
- drilling costs
- drilling success rate
- long-term reservoir behavior
- the number of “make-up” wells that will be required due to gradual resource degradation over the project life
- the optimum production/injection scheme (depths and locations of production and injection wells)
- pressure decline or cooling due to offset production from neighboring developments (i.e., the situation regarding resource access)
- fluid chemistry issues (corrosion, scaling, high non-condensable gases)

Of the above issues listed, three key items specific to larger scale geothermal resource development for electricity in California include identifying productive resource areas, dealing with competing use of the areas, and access to transmission lines.

7.0 Economic Analysis

After completing the resource assessments and project cost analysis, a pro forma financial model was developed for the SFPUC that estimates the LCOE for the different renewable energy options. A number of assumptions were made in this model regarding project financial structures and likely incentives. This section provides an overview for the structures and incentives considered, along with justification for the assumptions used in the model. The model has the flexibility to test a range of different scenarios, making it adaptable to changes that may occur in the financing and support for renewable energy technologies.

7.1 RENEWABLE ENERGY FINANCIAL INCENTIVES

A number of financial incentives are available for the installation and operation of renewable energy technologies. These incentives can substantially influence profitability and can make a large economic difference. The following discussion provides a brief list of existing incentives that are available to new renewable energy facilities. It should be noted that the intent of this section is to provide general information on available incentives; the availability of each incentive can be dependent upon overall enrollment and legislative action.

7.1.1 U.S. Federal Government Tax Incentives

The predominant federal incentive for renewable energy has been offered through the U.S. tax code in the form of tax deductions, tax credits, or accelerated depreciation. An advantage of this form of incentive is that it is defined in the tax code and is not subject to annual congressional appropriations or other limited budget pools (such as grants and loans). However, sunset provisions in the tax code can impact project eligibility. Tax-related incentives include:

- Section 45 Production Tax Credit (PTC)
- Section 48 Investment Tax Credit (ITC)
- Accelerated Depreciation
- New Market Tax Credits (NMTC)

The Section 45 PTC is available to private entities subject to taxation for the production of electricity from various renewable energy technologies. The income tax credit amounts to 1.5 cents/kWh (subject to annual inflation adjustment and equal to 2.3 cents/kWh in 2013) of electricity generated by wind, solar, geothermal, and closed-loop biomass. The credit is equal to 0.75 cents/kWh (inflation adjusted, equal to 1.1 cents/kWh in 2013) for all other renewable energy technologies. A problem with the credit is the ever-present threat of expiration, which promotes boom and bust building patterns. The PTC was extended in February 2009 as part of H.R. 1, the American Recovery and Reinvestment Act (ARRA, or the "Stimulus Bill"), then further extended and modified in January 2013 as part of the American Taxpayer Relief Act of 2012 (H.R. 6). H.R. 6 extended the eligibility of wind for one year and replaced the requirements that projects be "placed in-service" by set deadlines for eligibility with a requirement that projects only need to have begun construction. Projects that have not begun construction by the end of 2013 are no longer eligible for the PTC as of January 2014.

Major provisions of the Section 45 PTC are presented in Table 7-1.

Table 7-1 Major Production Tax Credit Provisions

RESOURCE	ELIGIBLE CONSTRUCTION START DATES	CREDIT SIZE*	SPECIAL CONSIDERATIONS
Wind	12/31/93 - 12/31/13	Full	
Biomass			
Closed-Loop	12/31/92 - 12/31/13	Full	Crops grown specifically for energy
Closed-Loop Cofiring	12/31/92 - 12/31/13	Full	Only specific coal power plants
Open-Loop	Before 12/31/13	Half	Does not include cofiring
Livestock Waste	Before 12/31/13	Half	>150 kW.
Geothermal	12/31/99 - 12/31/13	Full	
Small Irrigation Hydro	10/22/04 - 12/31/13	Half	No dams or impoundments; 150 kW-5 MW
Incremental Hydro	10/22/04 - 12/31/13	Half	Increased generation from existing sites
Landfill Gas	8/8/05 - 12/31/13	Half	
Municipal Solid Waste	10/22/04 - 12/31/13	Half	Includes new units added at existing plants

Notes:
- **All PTCs are inflation-adjusted and equaled $23/MWh ("Full") or $11/MWh ("Half") in 2013.**

The Section 48 ITC effectively offsets a portion of the initial capital investment in a project. While investor owned utilities originally were not eligible to receive the ITC, the extension of the ITC passed in 2008 changed this wording to allow utilities to claim the ITC if they have a tax burden. In addition, the ARRA expanded the eligibility to a broader range of resources. The ITC provisions are now:

- Solar – Eligible solar equipment includes solar electric and solar thermal systems. The credit amount for solar is 30 percent for projects that are place in service prior to December 31, 2016; after that, the credit drops to 10 percent.
- Geothermal – Geothermal includes equipment used to produce, distribute, or use energy derived from a geothermal deposit. The ARRA increased the credit amount to 30 percent for units that begin construction by the end of 2013, except for heat pumps where the credit is limited to 10 percent through 2016.

- Wind – Projects eligible for the PTC are also ITC eligible. Units must have begun construction by December 31, 2013.
- Biomass, LFG, hydro, and anaerobic digestion – Units must have begun construction by December 31, 2013.

The ARRA language that expanded the PTC does not allow claiming of both the PTC and the ITC. Project developers must choose one or the other. For capital-intensive projects, the ITC is typically more attractive. For projects with lower capital cost and higher capacity factors, the PTC might be more advantageous. 2009 analysis by Lawrence Berkeley Laboratory has quantified when the PTC or ITC is more attractive for a project investor.[12] For this project, the ITC was used for eligible projects and structures. The ITC also interacts with accelerated depreciation, as discussed further below.

Section 168 of the Internal Revenue Code contains a Modified Accelerated Cost Recovery System (MACRS) through which certain investments can be recovered through accelerated depreciation deductions. There is no expiration date for the program. Under this program, certain power plant equipment may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation, while other equipment may also receive less favorable depreciation treatment. Renewable energy property that will receive MACRS includes solar (5-year), wind (5-year), geothermal (5-year) and biomass (7-year). Typically, the majority of the project capital cost, but not all, can be depreciated on an accelerated schedule. The ARRA included a "bonus depreciation" allowance for most qualified renewable energy facilities that allowed 50 percent depreciation during the first year of operation. The American Taxpayer Relief Act of 2012 extended the deadline so that facilities that are placed in service by the end of 2013 are eligible. Given the limited number of resources that could qualify for bonus depreciation, it was not included in the cost evaluation. The accelerated depreciation law also specifies that the depreciable basis is reduced by the value of any cash incentives received by the project, and by half of any federal investment tax credits (e.g., the ITC). This provision has the effect of lowering the depreciable basis to 95 percent for projects that receive the 10 percent ITC and 85 percent for projects that take the 30 percent ITC.

New Market Tax Credits (NMTC) are credits for up to 39 percent of the qualified investment made in low-income communities. The NMTC is a broad development support program that is open to a range of investments, not just energy projects. While the specific eligibility requirements and application process is lengthy, the benefits can be substantial. As with the ITC/PTC, only taxable entities are eligible for the NMTC. Unlike the ITC/PTC, there are very complicated transaction rules and not all projects that apply for NMTCs will be granted an award. The US Treasury holds allocation rounds then reviews applications and selects awardees. Given the complexity, competition, and very specific terms required for an NMTC award, few renewable energy projects have been able to utilize this incentive. For the purposes of SFPUC modeling, the NMTC was excluded from the analysis.

[12] "PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States.", report NREL/TP-6A2-45359, March 2009.

7.1.2 U.S. Federal Government Non-Tax Related Incentives

A range of different types of non-tax incentives have been available to renewable energy project developers, but they tend to be much more limited in funding and of a shorter timeframe relative to tax-based incentives. The most widely recently used grant, the 1603 program, was passed as part of the ARRA bill but has since expired.

Many of the current non-tax related incentives are targeted at non-taxable entities such as municipally owned utilities. Government-owned utilities and other tax-exempt entities are not able to directly take advantage of tax incentives. Tax-exempt entities, however, do enjoy a number of other benefits when financing and operating capital investments. The most obvious benefit is freedom from federal and state income tax liability. Depending on project location and local laws, payment of property taxes may also be reduced or eliminated. These entities are also able to issue tax-exempt debt, which carries lower interest rates than comparable corporate debt.

Non-tax incentive programs available today to support renewable energy include the following:

- US DOE Renewable Energy Production Incentives
- Clean Renewable Energy Bonds
- Qualified Energy Conservation Bonds
- Rural Energy for America Program Grants and Loan Guarantees
- DOE Loan Guarantees

The federal government has established two primary incentive programs for non-taxable entities, but neither of which is currently providing any support. These are the Renewable Energy Production Incentive (REPI) and Clean Renewable Energy Bonds (CREBs). Neither program is intended for privately-owned projects, and both rely on limited congressional appropriations. Originally authorized in 1992, the REPI program was renewed by the Energy Policy Act of 2005 but has not received any funding allocation since 2009. The program provided payments to tax exempt entities, but the amount of funding was limited to whatever was provided during annual appropriations. In 2009 just one-third of project payment requests received funding.

CREBs were introduced as part of the Energy Policy Act of 2005 as a response to the perceived problems with the REPI program. CREBs provide interest-free loans to public utilities (including rural electric co-ops), while providing tax credits to purchasers (the investors who buy the bonds). The program is patterned after the Qualified Zone Academy Bonds (QZABs) used to finance school improvements. Congress authorized $2.4 billion in bonds in 2008 and 2009. The IRS has typically indicated that projects would be funded starting with the smallest request and continuing with the next smallest until the funds are exhausted. This makes the CREB funds much more likely to be available for small projects. While it is unclear if the full funding allocation has been issued, there is no current pathway for obtaining CREBs. The application deadline for the most recent round of CREBs was November 1, 2010, and there is no indication of a new round of funding available in the near future.

A government bond financing program that is open is the Qualified Energy Conservation Bonds (QECBs). These are similar to CREBs in that they have been created to help state and local government entities finance energy efficiency and renewable energy projects. Once a QECB is issued, the government agency issuing the bond pays back the bond principal, while the bond holder receives a federal tax credit in lieu of traditional bond interest. Unlike CREBs, there is no federal application process. Each state is allocated a cap for the amount of QECBs that may be issued, with a state agency being responsible for administration of the program. California has been allocated $381 million in funds which is being administered by the California State Treasurer. As of the end of 2012, it appears that funding is still available for interested qualified parties.

The Rural Energy for America Program (REAP) promotes energy efficiency and renewable energy for agricultural producers and rural small businesses. Federal grants and loan guarantees are available through REAP. Congress must allocate grant funding on an annual basis, and the level of overall funding and funding per project is limited. For the most recent solicitation (April 2013), individual project grants for up to 25 percent of the project cost were available, provided that they did not exceed $500,000. Loan guarantees are not to exceed $25 million. If awarded both a grant and a loan guarantee, the combined total must not exceed 75 percent of the project's cost. The present deadline for entities to apply for grants and loan guarantees was July 15, 2013, although additional funding periods are currently being considered in the 2013 Farm Bill. To be eligible for funding, the SFPUC would likely need to partner with a developer that would be eligible for funding under the REAP program for development of projects in rural locations. The limited funding levels and unique partnership requirements make the REAP program unlikely to be a likely funding source.

Under the Energy Policy Act of 2005 the DOE was authorized to issue loan guarantees for projects that reduced greenhouse gas emissions or demonstrated "new or significantly improved technologies". Large projects with a total cost greater than $25 million were the primary focus of this program. Loan guarantee recipients are required to repay loans in full at 90 percent of the useful life of the project (or 30 years, whichever is sooner). Currently there are no solicitations open, but future solicitations may become available.

7.1.3 State and Local Financial Incentives

California and the City of San Francisco have a number of policies and incentives that support the deployment of renewable energy projects. The major support mechanisms that are relevant to projects that may be developed by the SFPUC or within the City of San Francisco are the following:

- Renewable Portfolio Standard (RPS)
- Net Metering
- Global Warming Solutions Act (AB32) Cap and Trade Program
- GoSolarSF
- GreenFinanceSF

Through its RPS program California has created demand for renewable energy projects. Utilities are required to meet 33 percent renewable energy by 2020. Under changes to the RPS as of January 2011, Renewable Energy Credits (RECs) may be used for RPS compliance. One REC is equivalent to 1 MWh of electricity generated by renewable resources. Tradable RECs may be used to meet up to 25 percent of a utility's compliance requirement through December 21, 2013; afterwards this threshold is reduced until it reaches 10 percent in 2017. The REC price is currently capped at $50.

The SFPUC is required to meet all its retail sales through power generated by Hetch Hetchy and eligible RPS resources. In years where Hetch Hetchy power does not meet the full retail load, the SFPUC can meet its obligation through any combination of RECs and RPS eligible power. If the SFPUC builds renewables in excess local demand, there will be a retail market for the power and RECs beyond the obligations that the SFPUC has for power sales. However, at least in the short-term, the value for the REC is likely to be low given the aggressive procurement efforts that have already been performed by the state's utilities. Data from tracking organizations shows that tradable RECs (Bucket 3) are currently priced at around $1/MWh, roughly equivalent to Green-e RECs that are used for voluntary compliance.[13]

While these low prices limit the value that the RPS brings to new renewable generation projects through 2020, proposed efforts to raise the California RPS beyond 33 percent may provide greater incentives in the future. Given the cap on REC prices, it may be less expensive for the SFPUC to purchase RECs to meet future RPS obligations in the short-term.

All utilities in the state provide net metering access to customers. Net metering is a program where customers are allowed to install generation on their property and sell any excess back to the utility. Limits exist on the maximum size of a generation unit at a customer's property and the total amount of aggregate capacity on a utility's system. Up to now, net metering has not played a large role at the SFPUC because of the nature of the customers that are supplied. However, if the customer base at the SFPUC expands, net metering is a program that will need to be taken into account when estimating the costs and benefits of in-city renewable projects.

The cap and trade program implemented by the Global Warming Solutions Act (AB 32) has imposed a cost on statewide carbon emissions. Beginning in 2013, regulated entities in California must submit allowances for carbon emitted from large point sources of CO_2. Regulated entities include those with over 25,000 tonnes per year of CO_2 emissions, impacting roughly 600 facilities in the state. Beginning in 2015, transportation fuels and natural gas will also be included in the compliance obligations. Regulated entities have the following major options for meeting their obligations: reduce their emissions footprint, use free California Air Resource Board (CARB) allocations (which decline over time), buy credits, or obtain offsets. Carbon credits in the May 2013 auction averaged $14.25/metric tonne for vintage 2013 credits and $11.02/metric tonne for vintage 2016 credits, slightly higher than the $10/metric tonne floor defined by the statute.

The SFPUC receives a free allocation of credits from CARB and does not have a compliance obligation due to its sources of generation. Therefore, inclusion of additional low carbon resources has little value for the SFPUC under AB 32.

[13] See "Green-e RECs Edge Up To Compliance Value", available at http://www.renewableenergyworld.com/rea/blog/post/print/2013/05/green-e-recs-edge-up-to-compliance-value

Both the GoSolarSF and GreenFinanceSF are meant to stimulate development of solar energy within San Francisco. The GoSolarSF program provides incentives to residential, low income residential, and commercial buildings to develop solar PV on their properties. The basic benefit for residential properties is $2,000; for commercial properties it is $1,500/kW (up to a maximum benefit of $10,000), but this can change based a few factors such as income level and ownership by non-profits. Funding is limited to an overall cap per fiscal year. GreenFinanceSF is a Property Assessed Clean Energy (PACE) program where the costs for energy efficiency and solar projects are rolled into the property owner's yearly tax burden instead of being fully paid at the outset. San Francisco collects the loan repayments and distributes them directly to the lender. Both of these program help to stimulate and lower the cost of small scale, customer sited solar PV in San Francisco.

There are other state programs in-place which provide incentives or fixed prices to projects for customers of the investor owned utilities, but not the SFPUC. These include the Self Generation Incentive Program (SGIP), the CSI, the Renewable Auction Mechanism (RAM) and feed-in tariffs (FIT). The only comparable program available to SFPUC customers is the GoSolarSF program which provides an additional incentive to San Francisco residents already receiving a CSI rebate.

7.1.4 Future Term and Incentive Summary

The future of financial incentives is a source of uncertainty for new renewable projects. The PTC and ITC both expired at the end of 2013 for all technologies except solar (which will fall from 30 to 10 percent at the end of 2016). Projects must have begun construction by the end of these years to qualify. These incentives have a substantial impact on the cost of generation from renewables; cases with and without these incentives will have an appreciable difference in the levelized cost of electricity.

There is little basis on which to forecast future incentives. In the short-term, it is assumed that the SFPUC could likely contract with projects beginning construction in 2013 in any technology and thus capture the ITC. The economic model accompanying this report has the ability to "toggle" specific incentives to see the sensitivity of the results to different assumptions. In the base case, the ITC and accelerated depreciation are assumed for all technologies when owned by a taxable entity.

If the state RPS requirement increases to more than 33 percent renewables by 2020, this will likely increase the demand for new renewable projects and the value for RECs. However, since the SFPUC is already committed to procuring all new generation from renewable resources, this policy change would have little impact on either the project incentives or SFPUC procurement strategy unless the SFPUC desired to be in a position to sell excess RECs.

7.2 POTENTIAL OWNERSHIP STRUCTURES

The ownership structure of a project can have a material impact on the electricity cost paid by the SFPUC due to different incentive structures, cost of financing, and tax treatment. This section provides an overview of the major structures available and recommendations for structures that should be considered by the SFPUC. The financial model provided with this report will demonstrate the differences between some of the major structures.

7.2.1 Historical Approach to Renewable Energy Project Ownership

With the notable exception of hydroelectric facilities, renewable energy projects have typically been owned by industrial and independent power producers (IPP) with excess power sold to utilities through PPAs. There are historical reasons for the predominance of IPPs in the renewable energy sector. Renewable energy generation by IPPs was driven by the enactment of the Public Utilities Regulatory Policy Act of 1978 (PURPA), which stimulated the development of a large number of renewable energy projects in subsequent years. Many biomass, wind, and geothermal plants came online in this time period and were allowed under PURPA to sell excess power to the utility at avoided cost or other negotiated rates. As the influence of PURPA waned with lower electricity costs in the 1990s, a new round of renewable energy development was spurred by the PTC and ITC (discussed in the previous section). Public utilities are not able to directly realize the benefits of these tax incentives. The PTC and ITC reinforced the trend to contract renewable energy through PPAs for both public and investor owned utilities. Although there have been some utility owned renewable energy projects built in the recent past these projects have been the exception, and not the rule.

Based on past experience, interviews with other public utilities, and a literature review, the project team developed a list of potential project ownership scenarios that may be applicable to the SFPUC. Many different permutations and variations were identified, and include the following project elements:

- Project Structure – the basic arrangement that specifies ownership and operating control, capital flow, power flow, etc.
- Partners and Counter Parties – for public ownership, the various types of project partners and counter parties that may be involved in projects. These organizations may fill various roles including project owners selling power to the SFPUC, joint participants in ownership, power off-takers, plant operators, or other owners.
- Financing Approach – different sources of financing such as retained earnings, general obligation (GO) bonds, or project finance.
- Development Approach – degree of involvement in the project development process, ranging from complete self-development of a greenfield project to purchase of a turnkey project at commercial operation.

As illustrated in Figure 7-1, combinations of these different elements define different options. Not all elements are used to define each option. For example, for the purposes of this project, there would be no relevant counter-party in SFPUC ownership projects, and SFPUC's active involvement in development would be unusual for a typical PPA project, from which it purchased power.

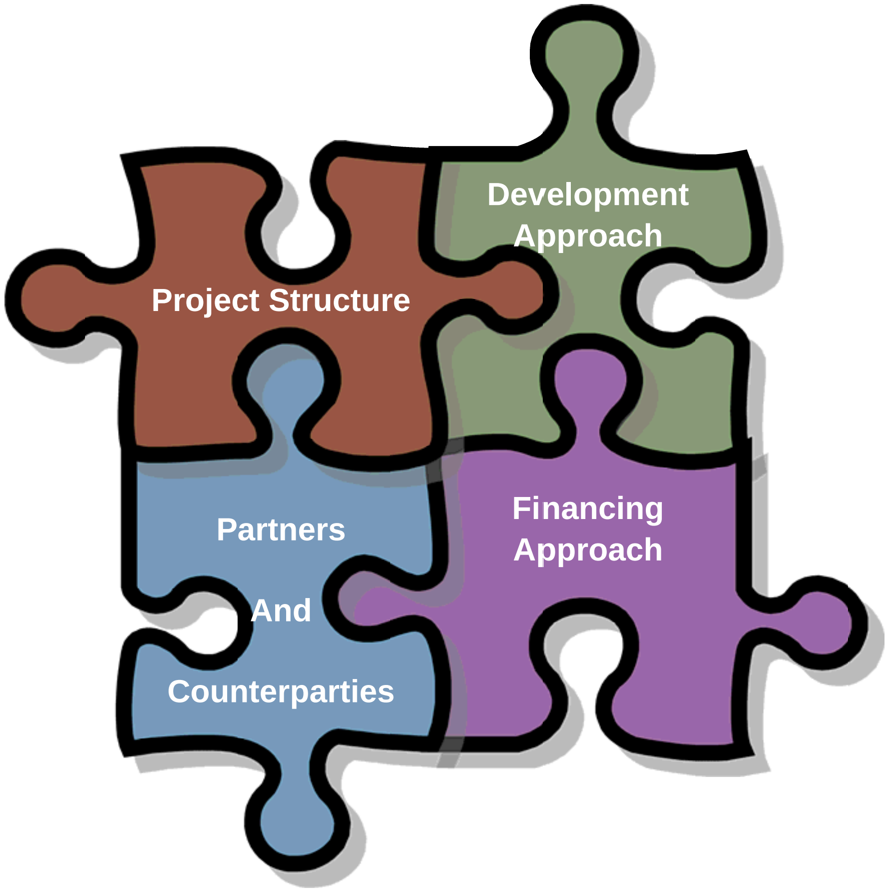

Figure 7-1 Elements Comprising the Various Project Ownership Options

The key consideration for analysis is the project structure element. The project structure will determine the overall form of the economic model. Other elements will typically impact economic variables within a model, such as the cost of debt. The next section explores five different finance structures assessed for this project. The section concludes with recommendations for structures to be considered by the SFPUC that will be carried through into the financial model.

The following sections describe each of the options and characterize advantages and disadvantages in several critical areas:

- Financing Costs – Indicates the relative cost of financing that the project may be likely to receive based on ownership structure.
- Development / Construction Risk – Assesses the relative level of risk the SFPUC would face for the project coming on-line (e.g., project permitting risk, technology risk, etc.).
- Financial Risk – Assesses the relative financial risk to the SFPUC for obtaining power through that ownership structure.
- Use of Tax Incentives – Assesses the degree to which the structure is able to take advantage of tax incentives to lower the cost of energy.

- Project Control – Assesses the relative level of risk the SFPUC would face for maintaining the level of operations required to achieve plant generation targets.
- Prevalence – Indicates the relative industry experience developing projects according to the given ownership structure.

7.2.2 Municipal Ownership

Perhaps the most straightforward ownership option for the SFPUC is direct project ownership. In this instance, the SFPUC would be the sole owner of the facility and would receive all energy generated. The SFPUC could be responsible for the development and construction of the project, or could purchase an already-constructed project developed by a private party. These and other development options involve various levels of development activity by the ultimate owner of the facility. Financing would be obtained through the municipal bond market with general obligation bonds or revenue bonds. Alternately, the project can be financed with internal retained earnings.

An example of this ownership option is the 120 MW Pine Tree Wind Farm near Mohave, CA which was the largest municipally owned wind project when finished in 2009. The project was developed by Horizon Wind Energy under direction and oversight of LADWP. LADWP actively participated in development activities and constructed the project substation and transmission line interconnection. This helped to reduce project costs and allowed LADWP to maintain control over modifications being made within their transmission system. Some municipal utilities such as LADWP prefer this type of structure to keep much of the project work, operations, and control of the unit within the utility. After successful commissioning, LADWP assumed ownership of the project by making a lump sum payment from their retained earnings to Horizon. LADWP now operates and maintains the wind farm. The general attributes of the public utility ownership option are characterized below:

- Financing Costs – Financing costs for publicly owned renewable energy projects are nearly always more attractive than for private projects due to tax-exempt financing. The financing rate varies slightly depending on whether general obligation or revenue bonds are issued.
- Development/Construction Risk – As the sole owner of the project, risks during the development and construction phase of the project are higher for municipal ownership versus other options, such as a PPA. To a certain extent, the SFPUC can control these risks by employing different development approaches (for example, self-development versus purchase of a turnkey facility).
- Financial Risk – The financial risk profile of the project is relatively high because the municipal utility is the sole party responsible for debt repayment, operations, and maintenance of the project.
- Use of Tax Incentives – Because it is a tax-exempt entity, under this structure the SFPUC cannot take advantage of incentives available to taxable entities (e.g., investor owned utilities (IOUs)). However, the SFPUC does not pay state or federal taxes.

- Project Control – The SFPUC has the greatest control over the project with this ownership option. The owner may elect to forfeit some of this control to others, such as a turnkey developer, in exchange for reduced execution risk.
- Prevalence – While there has been a few large municipally owned renewable energy projects developed in the last few years, municipal ownership remains very limited. There is currently roughly 1300 MW of municipally owned renewable energy projects, with the majority consisting of biomass projects built before the year 2000. Figure 7-2 shows the breakdown of ownership options for currently operating renewable facilities by technology based on data from Energy Velocity.

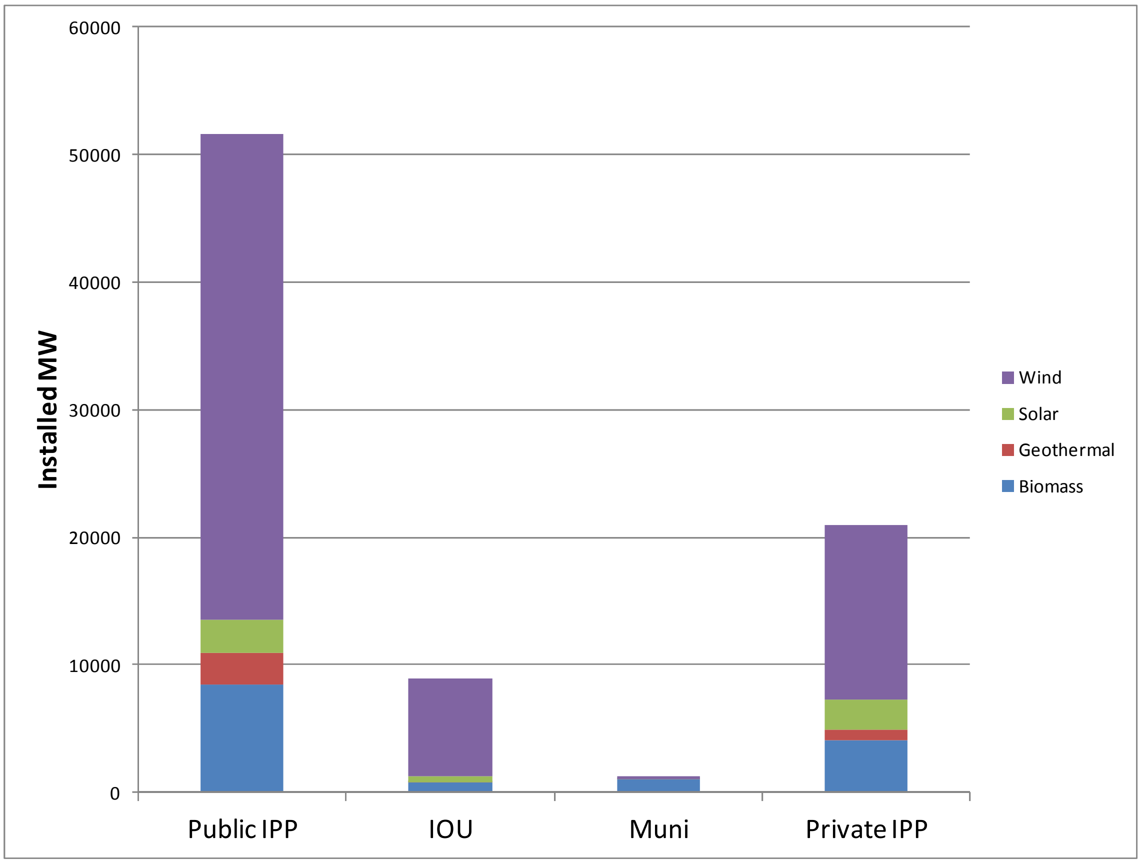

Figure 7-2 Cumulative Renewable Energy Ownership

Public ownership is a conventional project structure that affords the SFPUC a great deal of control over project development, construction, and operation. In exchange, the SFPUC assumes much of the project risk. These risks can be partially managed during the development phase by partnering with other companies. Financing costs for public ownership projects are generally low; however, the SFPUC would not be able to take advantage of the lucrative tax credits available to privately owned renewable energy projects.

7.2.3 Power Purchase Agreement

The purchase of renewable energy by a public utility through a PPA with an IPP is the most common way in which renewable energy projects have been developed in the recent past. PPAs provide low-risk delivery of power to the purchaser, usually for a set cost per unit of energy, while largely shielding the purchaser from project risks. In this arrangement, an IPP will either develop a project concept and market the power to various off-takers, or respond to an RFP from a utility for providing new generation. After securing the PPA(s), the IPP will close financing on the project and build it. Thereafter, ownership and/or operations may be sold or transferred to another private party. In either event, the utility would continue to receive and pay for power per the terms of the PPA. It is not uncommon for renewable energy PPAs to be offered with fixed prices over their full term. PPAs for renewable energy projects do not have to be exclusively with IPPs. Other potential counter parties include other public utilities, IOUs, individuals/community organizations, and federal suppliers.

There are many examples of PPAs between IPPs and public utilities in California. Recent ones include SMUD's 30 MW PPA with Gradient Resources for power from the Patua Geothermal Plant and LADWP's 250 MW PPA with K Road Moapa Solar. The features of a typical PPA project are described below.

- Financing Costs – The cost of financing is typically higher for this option than municipal ownership. Developers will finance the project through financial markets, including commercially priced debt and equity.
- Development/Construction Risk – The development and construction risk for the PPA option is the low for the utility purchasing the power because the counter-party bears the full responsibility for these activities.
- Financial Risk – This option carries the lowest financial risk of any of the options considered for this study since the SFPUC would only pay for the power delivered. PPAs are not totally without risk; issues might arise in a few areas such as (1) take-or-pay agreements if the SFPUC is not able to receive the entire output of the project, (2) any agreement where the SFPUC assumes responsibility for PTC payments in case of output curtailment, and (3) failure of the power provider to perform, in which case the SFPUC may need to turn to alternative supplies of electricity. These risks can be controlled through contract negotiation and prudent due diligence of potential suppliers.
- Use of Tax Incentives – Taxable counter parties are able to claim tax incentives, and these benefits would, in theory, be passed on to the SFPUC in the form of lower PPA prices.
- Project Control – Control of the project development, construction, operations and maintenance would reside with the IPP.
- Prevalence – PPAs are the most common means by which renewable energy projects have been developed.

It is very common for a utility to obtain renewable energy from an IPP through a PPA. Doing so allows the utility to procure the energy at very little risk while allowing the project to claim tax incentives that are indirectly passed to the utility in the form of lower energy costs. Other benefits include limited exposure to development cost and leveraging the experience of a knowledgeable developer. The tradeoff is a lack of project control and possibly upward pressure on the PPA price for two main reasons. First, the project owner is not typically able to use low-cost tax-exempt financing. Second, it should be expected that the power seller, who assumes most the risk to develop the project, would charge the utility a price premium to counterbalance this risk.

At the end of the PPA term or the expiration of the PTC, the utility may choose to purchase the asset. This scenario (PPA with transfer) is discussed in more detail below.

7.2.4 Power Purchase Agreement with Transfer

This option is similar to the PPA option, but adds a provision for asset transfer to the SFPUC at the end of or during the PPA term. The developer must own and operate the project for at least six years to be able to claim any federal tax credits. The transfer price must be based on "fair market value" (FMV). This allows a taxable counter-party to receive all tax benefits and recover some portion of the capital cost of the project. SFPUC then buys the depreciated asset and assumes operation. This structure is popular with public and non-taxable agencies, and has recently been used or considered by groups such as Santa Clara University, Stanford University, and Salt River Project. The attributes of a PPA with transfer structure are described below:

- Financing Costs – The project would initially be financed with higher-cost commercial finance. Upon transfer, the transfer price paid by the utility might be paid using retained earnings or low-cost tax-exempt debt, reducing the aggregate cost of the facility. However, there is some risk that tax-exempt financing may not be allowable for purchasing an existing asset, and a legal opinion of this matter should be sought before proceeding.
- Development/Construction Risk – The development and construction risk of this structure would be low, similar to the PPA option.
- Financial Risk – The financial risk of this option would be low and similar to that of a PPA for the initial term. The largest risk with this option is the cost and condition of the asset upon transfer to the SFPUC. Per IRS guidelines, the developer must own the project for at least six years and a pre-agreed transfer price is not allowed if the developer would like to capture federal tax credits. Therefore, the cost of transfer is not known in advance. Further, the SFPUC would not have direct control over the operations and maintenance of the plant when owned by the private party. There are several methods to mitigate these risks including (1) making the transfer optional, (2) specifying required O&M procedures or a third party O&M company, and (3) defining how FMV will be calculated as a way to reduce the uncertainty while staying within IRS guidelines.
- Use of Tax Incentives – Taxable counter parties are able to claim tax incentives, and at least a portion of these benefits should be passed on to the SFPUC in the form of lower PPA prices.
- Project Control – The project control profile would mirror that of the PPA before the transfer of the facility to the SFPUC, and would mirror that of direct SFPUC ownership after that point. The SFPUC may assert control over some aspects of O&M during the PPA phase to

assure that the plant is in good condition when transferred or place specific condition requirements in the contract.

- Prevalence – While few examples of this structure existed five years ago, this type of structure is becoming much more common amongst public agencies as a way to develop renewable energy projects at a low cost. Taking ownership reduces the rent and royalty payments to the developer and allows the public agency more active control in the project's operations. The agency must feel comfortable operating and maintaining the project, and that costs to do this would be commensurate to those of the developer.

The PPA with transfer combines many of the advantages of the PPA and direct project ownership options. The use of a PPA with a taxable counter-party should allow tax benefits to be indirectly passed to the SFPUC in the form of lower PPA payments. Further, development and construction risk is primarily assigned to the project developer, although the lack of utility involvement in daily O&M decisions might increase long term performance risk in the event of project acquisition. The SFPUC would need to structure project agreements carefully to manage this risk. The use of tax-exempt debt to purchase the project at the transfer date would further improve the economics. However, there are questions as to whether tax-exempt debt could be used for this purpose.

7.2.5 Pre-Paid Power Purchase Agreement

The PPA prepayment option follows the general form of a conventional PPA; however, payment for part of the power is made in one lump sum at the beginning of the PPA term. For the remainder of the power that is not pre-paid, the utility would pay an ongoing "tariff" to make up the difference. The US Treasury Department issued a ruling in 2003 allowing publicly owned utilities to use tax-exempt financing to prepay future electric supplies.[14] This type of structure is not very common in the public power sector, since it tends to be complicated and only makes economic sense for larger projects. Examples include Memphis Light, Gas and Water's 15-year, $1.5 billion agreement with Tennessee Valley Authority in 2003[15] and SMUD's 2012 agreement with Vestas and Citigroup for Phase 3 of the Solano Wind Project.[16]

A prepay structure could be cost effective since the public agency is in effect paying a large portion of the capital cost with low cost tax-exempt debt or retained earnings. The net cost for the delivered power may be potentially lower if the municipal debt rate is lower than the effective after tax debt rate of the private developer. However, prepaying for electricity in advance of delivery could entail a high level of risk. The public agency must come up with a large payment at the start of the project before any power is delivered. Any agreement would need to include significant penalties for failure to deliver power and provisions intended to minimize risks to the SFPUC. Also,

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[14] US Department of the Treasury, "Treasury Issues Final Regulations Regarding Pre-payments Financed with Tax-Exempt Bonds," available at http://www.ustreas.gov/press/releases/js629.htm, August 1, 2003.

[15] Tennessee Valley Authority, "Treasury Approves Innovative TVA-MLGW Pre-pay Deal," available at http://www.tva.gov/insidetva/august03/treasury.htm, August 2003

[16] https://www.smud.org/en/about-smud/news-media/smud-updates/2012-05-01-solano-expansion.htm

the IRS has guidelines for the maximum amount of power that can be pre-paid; if the level is too high, the public agency will be ruled to be the true owner, preventing the tax incentives from being used by the developer. This limit is general thought to be around 50 percent, although there is no explicit limit and views on the limit differ. Black & Veatch highly recommends discussions with a tax attorney before engaging in a prepay PPA. The characteristics of a project employing the PPA prepayment structure are described below.

- Financing Costs – Though the private owner of the facility would have to access more costly commercial markets for debt and equity, the SFPUC would be able to use low-cost tax-exempt bonds to fund the prepayment of the PPA. Because the SFPUC's cost of capital is lower than that of the IPP, such a prepayment could be economically advantageous.
- Development/Construction Risk – Similar to a PPA, the development and construction risk profile for the SFPUC is very low; the counter-party is responsible for all project development and construction risk.
- Financial Risk – There is considerable financial risk in this type of transaction because of the large debt burden issued at the outset of the transaction, with a promise of future delivery but a risk of non-delivery. The SFPUC is essentially accepting the role that would traditionally be filled by project financiers. Prudent due diligence of the project and the proposing counter-party would be necessary. The SFPUC could reduce risk by only prepaying a small percentage of the total upfront energy costs, but this would reduce the value that this structure promises.
- Use of Incentives –If the project were developed by a taxable entity, use of tax incentives should be possible; the SMUD Solano project is an example of this type of structure being successfully arranged. Further investigation of incentive applicability and potential interactions with tax exempt financing is prudent.
- Project Control – Project control considerations are the same as a traditional PPA.
- Prevalence – This structure has been used for renewable energy technologies, but is rare. Only public agencies that have the ability to make a large upfront payment, are willing to accept financial risk, and that have a project large enough (at least 10 MW, but preferable larger) to make this type of structure worth the time and effort should consider a prepay PPA.

It may be possible for the SFPUC to procure power at substantially reduced rates through enhanced negotiating leverage with the PPA prepayment option for large projects. The SFPUC would have to make a fairly large, upfront financial commitment to enter into such an agreement. The risks of doing so would need to be carefully weighed against the advantage of securing low-cost power.

7.2.6 Real Estate Investment Trust

Renewable energy investors have recently considered the use of REITs as a tax-efficient investment structure. A REIT is an investment fund that allows small investors to pool their money for purchases of real property, similar to a mutual fund. There are very specific rules defining how a REIT must operate that cover items such as the minimum number of investors, the amount of the REIT that can be held by an individual investor, and most importantly, the types of assets that can be held by a REIT. By law, 75 percent of a REIT's assets must be "real estate assets", cash, and government securities. There are major questions on if renewable energy equipment, such as wind turbines and solar panels, will pass the IRS definition of "real estate assets" since most of this equipment does not pass the "inherently permanent" test. Also, the sale of inventory from REITs is a "prohibited transaction"; it is likely that the sale of electricity will be classified as "inventory" if held in a REIT.

The advantage of REITs comes in how they are treated for tax purposes. By law, at least 90 percent of a REIT's revenue must be distributed as dividends to shareholders. These dividends are deducted from the REIT's net taxable income. By reducing corporate income tax and thus taxing most revenue at the personal dividend rate, the net tax burden is lower. REITs have been used in the energy industry largely for oil and gas investments, by allowing the purchases of land and non-building, non-machinery equipment. REITs will have limited ability to use the federal PTC or ITC; the amount of the tax credit is reduced by the level of dividend distributions, and the individuals who receive the dividends are unable to claim them. Therefore, while the PTC and ITC are still available, REITs are unlikely to play a large role in the renewable energy industry.

A REIT is not really a full project finance structure, but largely a way to obtain development financing that can be used in a PPA, PPA with transfer, or pre-paid PPA structure. There are both companies looking to invest specifically in renewable energy REITs and traditional REITs looking to add renewable assets to their portfolio. There are currently two REITs with some investment in renewable energy: Hannon Armstrong and PowerREIT. While PowerREIT is investing only in property that may be used for renewable energy, the Hannon Armstrong REIT holds largely energy efficiency investments, with less than one-third of the REIT targeted for investment in renewable projects. Hannon Armstrong requested a private letter ruling (PLR) from the IRS that allowed their specific situation to be approved. The current view in the industry is that this is a "boutique structure" that is not widely applicable to others. The characteristics of a project employing a REIT are described below.

- Financing Costs – It is unclear how project financing being developed by a REIT will impact the overall financing cost. It may be lower than bank financing, since returns (dividends) on the project will be taxed at a lower rate than corporate financing.
- Development/Construction Risk – A REIT would provide funding to a developer who could then utilize any type of project agreement they wished. There is no additional risk in this area created through establishment of a REIT.
- Financial Risk – There is major risk with the use of a REIT for financing since there are a number of hurdles to acceptance of this type of structure for renewable energy. If a REIT was found to be appropriate for financing, then the financial risk to the SFPUC should be no different than the other structures, depending on what type of arrangement was established.

- Use of Incentives – Unlike the other structures evaluated, a REIT would be a poor vehicle for use of federal tax incentives. This could make the cost of the overall project higher that the other options evaluated while the ability to claim the PTC or ITC exists.
- Project Control – As with development/construction risk, a REIT does not establish any additional risk in this area.
- Prevalence – There are no REITs that have been established purely for the development of new renewables. Given the "real property" issues and inability to fully utilize the tax credits, it is unlikely that REITs will be widely used for renewable projects anytime soon.

Given the barriers to the use of REITs and the uncertainty regarding their viability in the current market, it is not recommended that the SFPUC consider this funding mechanism as an option for near-term project financing.

7.3 ECONOMIC AND FINANCING ASSUMPTIONS

Black & Veatch developed a financial model to assist the SFPUC in evaluation of different renewable energy and financing options. This model is provided as a separate deliverable to this report. The model inputs for the cost and performance of different types of solar PV, wind, and geothermal projects, along with letting the user modify these inputs as desired. In addition, each of the different project types can be paired with a different financing option. Based on the analysis above, SFPUC ownership, PPA, PPA with transfer, prepay PPA, and prepay PPA with transfer are all options that can be chosen for evaluation.

Major inputs for the SFPUC and private ownership cases can be seen below.

Table 7-2 Economic Analysis Assumptions

PARAMETER	SFPUC OWNERSHIP	PRIVATE OWNERSHIP
Debt Percentage	100 percent	45 to 50 percent
Debt Rate	3.8 percent	6.5 percent
Debt Term (years)	30	15 for solar and wind, 20 for geothermal
Economic Life (years)	20 for wind, 25 for solar, 30 for geothermal	
Depreciation Term (years)	N/A	5 years
Percent Depreciated	N/A	85 percent
Tax Rate	N/A	40 percent
Equity Percentage	0 percent	55 percent (60 percent in the prepay scenario)
Cost of Equity	N/A	8 percent for prepay, 10 percent otherwise (12 percent for geothermal)
Discount Rate	3.8 percent	N/A
Inflation	2.0 percent	
Debt Service Coverage Ratio	1.2 to 1.3	

Other major assumptions and functionality for the model include the following:

- The discount rate used to calculate LCOE is based on SFPUC's weighted cost of capital of 3.8 percent.
- General inflation factor of 2 percent per year was applied to all O&M costs.
- The model is able to accommodate a Possessor Tax as part of the land lease for the private ownership finance options. For the base case analysis, no Possessor Tax was assumed.
- For transfer scenarios, transfer is assumed to occur at year 7, after the tax credits have been monetized. The methodology for calculating the transfer price is based on the present value of the earnings before interest and taxes (EBIT) stream of the project in year 7 discounted at the developer's equity return rate.
- For prepay PPAs, it is assumed that 40 percent of the energy is pre-paid at the outset of the project.
- Additional incentives, either for municipal ownership or private ownership, can be included in the analysis. The ITC and accelerated depreciation are the only incentives included in the results presented here, although changes to the ITC, PTC, or other incentives can be modeled.

The estimated LCOE for each of the projects modeled under the different ownership options can be seen in the next section.

7.4 ECONOMIC ANALYSIS RESULTS

The LCOE estimates for each different technology are shown below, along with a discussion of the results. Following the technology specific results is a comparison of ownership options for the projects with the lowest LCOEs. Finally, a supply curve comparing the options between technologies and recommendations for future SFPUC development is provided in Section 7.5.

The costs shown below reflect the busbar cost of generation, but not necessarily what SFPUC would pay to obtain energy produced from each project. The price of energy is impacted by other market factors such as overall supply and demand, site specific development considerations not reflected here, the value of the power given its generation profile, and cost of power delivery to the load. For example, many geothermal PPAs are signed at values higher than those shown here given the higher development risk faced by geothermal projects and lower amount of competition for baseload renewable resources.

7.4.1 Solar Photovoltaic

The results of the solar PV analysis shows that the up-country SFPUC locations and large statewide ground mounted facilities have considerably lower LCOEs when compared to rooftop development locations in San Francisco or any of the SFPUC water reservoirs. This is due to the larger size and better solar resource for the projects sited away from San Francisco. The costs for the projects located outside of San Francisco reflect transmission costs to intertie the power into the CAISO. Even once any charges from PG&E to bring the power into San Francisco are included, the LCOEs for the large ground mount projects will remain much lower.

For the three large ground mount projects (Midway, Windhub, and Imperial Valley), LCOEs for both fixed and SAT projects located on the same site were calculated. The good solar resource at all these locations justifies the higher capital cost of a SAT system, with LCOEs roughly 10 percent lower. Therefore, SAT projects only will be carried forward to future supply curve analysis.

While the results for all locations under each ownership option is listed below, prepay PPAs are typically only seen on larger projects due to their complexity and development costs. This structure would only be viable for rooftop, reservoir, and small ground mount systems if bundled within a larger portfolio of projects.

Table 7-3 Solar LCOEs ($/MWh), Different Ownership Options

PROJECT	PPA	PPA WITH TRANSFER	PREPAY PPA	PREPAY WITH TRANSFER	SFPUC OWNERSHIP
Hunters Point	$294.18	$222.67	$222.25	$226.66	$305.82
Marina School	$266.12	$198.39	$197.97	$202.14	$276.94
Thurgood Marsh.	$217.15	$162.58	$162.25	$165.61	$225.92
College Hill Res.	$227.24	$170.27	$169.93	$173.43	$246.21
Summit Res.	$243.18	$182.15	$181.78	$185.53	$252.99
Stanford Heights	$242.94	$181.98	$181.62	$185.37	$252.74
Sutro Res.	$223.81	$168.09	$167.76	$171.19	$232.79
University Res.	$205.37	$154.39	$154.09	$157.23	$222.38
Pulgas Res.	$199.05	$149.64	$149.35	$152.39	$207.02
Tesla Fixed	$112.60	$85.40	$85.24	$86.92	$117.04
Sunol Fixed	$101.93	$80.48	$77.66	$79.15	$105.90
Midway Fixed	$104.69	$80.49	$80.35	$81.85	$108.71
Windhub Fixed	$95.73	$73.60	$73.47	$74.84	$99.40
Imperial Valley Fixed	$99.12	$76.21	$76.08	$77.50	$102.93
Midway SAT	$95.48	$73.50	$73.38	$74.74	$99.13
Windhub SAT	$84.05	$64.70	$64.59	$65.78	$87.26
Imperial Valley SAT	$90.34	$69.54	$69.42	$70.71	$93.79

Notes:

- **Reflects busbar cost of new generation using typical industry development assumptions; SF and SFPUC owned sites adjusted to reflect local costs. These numbers are not necessarily what the SFPUC will pay due to market factors and SFPUC development considerations.**
- **Rooftop and reservoir development costs assume no structural modifications are required.**
- **Prepay PPAs are viable for large scale projects only; small projects would need to be bundled in a larger portfolio.**

The results show that PPA with transfer and prepay options have LCOEs roughly 25 percent lower than straight PPAs or SFPUC ownership. However, it is unlikely that a prepay option could be used for the smaller projects (city rooftops, reservoirs, and Tesla) unless they were aggregated into a large financing bundle.

7.4.2 Wind

The results of the wind analysis shows that the in-city and up-country locations on SFPUC land are located in much poorer wind resources areas, leading to considerably higher LCOEs. In addition, these locations have less land for development when compared to the other locations analyzed throughout the state, which could build a large facility and take advantage of economies of scale. Finally, while the operating cost of the Oceanside facility has been raised to try to reflect the unique operating conditions for an urban wind facility, the ability to permit and obtain local acceptance of a wind project in this location would be much more challenging than the other project sites.

Table 7-4 Wind LCOEs ($/MWh), Different Ownership Options

PROJECT	PPA	PPA WITH TRANSFER	PREPAY PPA	PREPAY WITH TRANSFER	SFPUC OWNERSHIP
Oceanside	$96.77	$82.01	$82.59	$83.46	$105.91
Sunol	$156.72	$129.85	$130.92	$134.36	$173.34
Tesla	$126.38	$104.33	$105.21	$108.03	$140.02
Montezuma Hills	$66.44	$56.13	$56.54	$57.14	$72.81
Altamont Repower	$67.43	$56.63	$57.06	$57.69	$74.12
Walnut Grove	$65.22	$54.89	$55.30	$55.91	$71.60
Leona Valley	$68.05	$56.85	$57.30	$57.96	$74.97
Newberry Springs	$67.07	$56.34	$56.77	$57.40	$73.71

Notes:
- **Reflects busbar cost of new generation using typical industry development assumptions. These numbers are not necessarily what the SFPUC will pay due to market factors and SFPUC development considerations.**
- **Further environmental permitting viability must be performed at all sites, especially Oceanside and Montezuma Hills.**
- **Prepay PPAs are viable for large scale projects only; small projects would need to be bundled in a larger portfolio.**

As will be seen in the other technologies, the prepay and transfer options have lower LCOEs when compared to either a straight PPA or SFPUC ownership. This is due to the use of both the ITC and the SFPUC's low cost of debt in each of these ownership scenarios. As mentioned above, prepay PPA structures tend to be complicated and typically of interest to only larger developers pursuing fairly large projects. Given these issues, a PPA with transfer appears to be the best choice for wind development. Any of the statewide projects outside of San Francisco or SFPUC controlled lands would be of a size and structure suitable for this type of financial arrangement.

7.4.3 Geothermal

All of the geothermal projects analyzed are promising and could provide low cost power to the SFPUC. However, the challenge with any new geothermal project is assurance that the heat resource can produce at the projected output levels and cost projections. Capital costs of geothermal facilities can vary widely for several reasons, but one of the most important variables is the drilling cost to develop the resource. During the exploration phase it is common to have one or more holes that are found to be unable to provide temperatures or flow rates that support commercially attractive development. Once defined and proven, the development wells (production and injection) are drilled. Well costs increase non-linearly with depth, so if a resource is found to be deeper than expected costs will increase. Factors like this, as well as potential scaling and corrosion issues during operation, make cost estimates less certain than for other types of renewable energy. Furthermore, geothermal projects tend to have long lead times as exploratory well drilling could last as long as 2 to 5 years or more.

Table 7-5 Geothermal LCOEs ($/MWh), Different Ownership Options

PROJECT	PPA	PPA WITH TRANSFER	PREPAY PPA	PREPAY WITH TRANSFER	SFPUC OWNERSHIP
Long Valley Binary	$77.39	$63.81	$67.47	$68.00	$78.02
Geysers Flash	$65.96	$53.37	$56.77	$57.26	$66.54
Brawley Binary	$77.65	$61.91	$66.16	$66.77	$78.37

Notes:
- **Reflects busbar cost of new generation using typical industry development assumptions. These numbers are not necessarily what the SFPUC will pay due to market factors.**

PPA with transfer and the prepay PPA cases remain the most attractive ownership options. The low cost of capital available to the SFPUC makes options where the utility takes over ownership of the project more attractive than this type of structure for other technologies. This is because the investment risk is higher to private investors leading to a higher cost of private equity.

Based on Black & Veatch and SFPUC's experience with recent market pricing for geothermal projects, the costs estimated in this report are significantly below the prices being offered in the market. While the prices shown above may reflect the development cost for the best known resource areas, a number of factors, including development risk, higher investor return expectations, project costs, uncertainty of pricing given the thin market for available projects, and resource availability would likely drive prices up beyond the costs estimated in this report. Furthermore, as a dependable baseload resource, geothermal developers may feel they offer a more valuable product than variable wind and solar resources. Due to this uncertainty, it was decided that the focus of the economic comparisons in the supply curve later should be on resources (wind and solar) that have a greater chance of development at costs consistent with on actual transaction prices. Nevertheless, SFPUC should still consider geothermal as a potentially competitive resource option.

7.4.4 Ownership Options

To better demonstrate the differences between the best resource and ownership options, the LCOEs for the best solar PV reservoir (Pulgas), ground mount solar PV (Windhub SAT), wind (Walnut Grove), and geothermal (Geysers) sites modeled as part of this analysis for each of the five ownership options are compared in Figure 7-3.

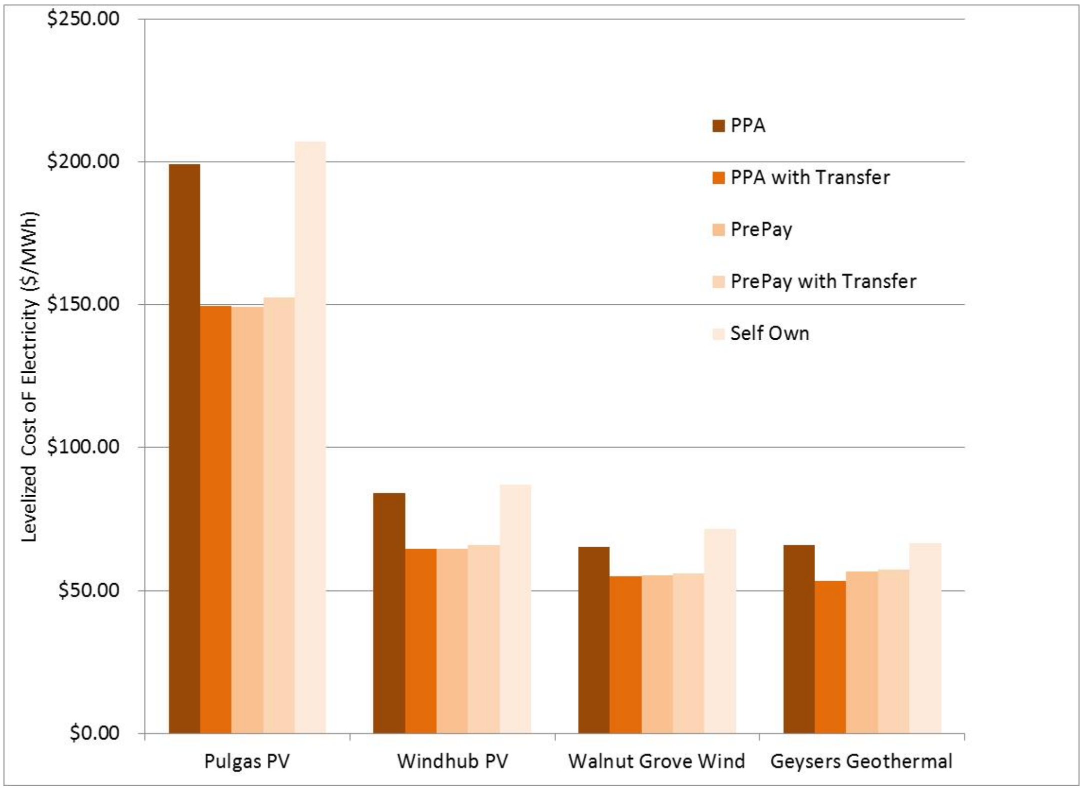

Figure 7-3 Ownership Option Comparison, Best Resources

From this analysis, conclusions can be made regarding the best resource and ownership options. The relative attractiveness of municipal self-ownership versus a straight PPA is highly dependent on the spread between the cost of capital for SFPUC and the developer. The very low cost of capital (3.8 percent) modeled for the SFPUC makes municipal ownership comparable to a straight PPA, albeit slightly more expensive. If the spread between the cost of capital to the SFPUC and private developers was to shrink, the municipal ownership option would look less attractive.

In general, the PPA with transfer and both prepay PPA options have lower LCOEs for all technologies when compared to straight PPAs or SFPUC ownership because the municipality is able to benefit in two ways: (1) the developer is able to pass through the savings from federal tax credits and accelerated depreciation in the form of lower PPA pricing while (2) the municipality is able to utilize low municipal cost of capital to finance a large portion of the capital cost of the project. These three options appear comparable to each other for the following reasons:

- At some point, whether it is in the first year as in the prepay option or in year seven as in the PPA with Transfer option, the SFPUC will finance a portion of the project cost, either directly or indirectly, using municipal bonds.
- Cost of debt for SFPUC of 3.8 percent is comparable to the after-tax debt rate of the developer in the PPA scenario of 3.9 percent (6.5 percent x (1- Tax Rate)) in the PPA with Transfer scenario.
- The debt term for the PPA scenario is assumed to be 15 years for solar and wind. Longer debt terms enable projects to have lower LCOEs.
- The portion of equity investment assumed in the PPA versus prepay scenarios are 55 percent and 60 percent respectively, while the equity return requirements are 10 percent (levered) and 8 percent (unlevered). The combinations of assumed equity percentage and equity return requirements for each of the scenarios result in similar LCOEs. While the equity return requirements reflect returns in highly competitive markets, the return requirements may be higher for some developers, especially under levered structures.

Since the relative ranking of these options lies in the assumptions, Black & Veatch tested the impact to LCOE in the PPA with transfer option as a result of changes to financing assumptions for the Windhub PV project. The analysis focused on the debt rate, debt term and equity return requirements. By testing the financing assumptions for the PPA with transfer scenario, one can see the LCOE change relative to the prepay options.

The sensitivity of the prepay option to changes in assumptions was also tested. Municipal bond rates were not modified since any change in the municipal bond rate may mean a corresponding change in commercial debt rates. The results of the sensitivities are shown in the table below. Note that in all cases, the debt portion was adjusted to achieve the same level of debt coverage as the base case, which is why the debt percent is not the same in all instances.

Table 7-6 Sensitivity Analysis of Developer Financing Assumptions for Windhub PV

FINANCING SCENARIO		DEBT RATE/ PERCENT*	DEBT TERM (YEARS)	EQUITY RATE (PERCENT)	LCOE ($ PER MWH)
Prepay	Base Case (40 Percent Prepay)	NA	NA	8	$64.59 without transfer $65.78 with transfer
	50 Percent Prepay	NA	NA	8	$56.26 without transfer $62.14 with transfer
PPA with Transfer	Base Case	6.5/45	15	10	$64.70
	High Debt Rate	**7.5/44**	15	10	$69.58
	Short Debt Term	6.5/38	**10**	10	$73.48
	High Equity Rate*	6.5/50	15	**14**	$63.46
	High Combined	**7.5/45**	**10**	**14**	$77.89

Notes

- **High equity rate scenario has a higher initial PPA price but lower transfer cost of the project in year 7 because the net present value of EBIT is discounted at the higher equity return rate. Thus, the LCOE appears slightly lower than the base case.**

For the sensitivity test, the prepay options appear to become more attractive if the prepay portion is increased to 50 percent. The base case analysis assumes a more conservative 40 percent; the larger amount of prepay, the greater risk that the IRS will consider the SFPUC the prepay the owner, potentially eliminating the ability to claim any tax credits by the developer.

In addition, the LCOE for the PPA with transfer is fairly sensitive to the financial assumptions, making prepay options appear more attractive under a number of changes to the financing assumptions, such as higher debt rates, shorter loan periods, and higher levered rates of return. However, SFPUC needs to weigh those potential benefits against the complexity and risks of the contractual agreement for a prepay scenario. Prepay PPAs are complicated, have higher structuring expenses, are better suited for larger projects, may encounter greater IRS audit risk, and may place some production risk on SFPUC.

Note that incremental legal expenses associated with prepay options are not captured here. In addition, if the federal tax credits (ITC and PTC) are allowed to expire, this would greatly reduce the incentive for the SFPUC to consider any type of PPA structure, prepay or not. In this case, the low cost of capital available to the SFPUC would favor self-ownership as the preferred option. This analysis is preliminary and is not intended to substitute for financial advisory services which the SFPUC should secure if any of these options are pursued.

7.5 SUPPLY CURVE OF RESOURCES

Figure 7-4 below is a supply curve comparing the LCOEs of the resources modeled relative to the amount of energy produced, with a tabular summary following in Table 7-7. A few notes regarding this curve:

- The preferred ownership option, PPA with transfer, is modeled for all technologies.
- Geothermal projects are not included in the supply curve due to the very limited number of available opportunities, competition for this resource, and uncertainty of costs (see Section 7.4.3).
- This supply curve only reflects a portion of the energy from projects modeled as part of this analysis. There are a large number of additional renewable resource options that could be available to the SFPUC. The intent is to provide a relative understanding for how the different resource types compare to one another; the net amount of generation potential available to the SFPUC is considerably greater than what is presented below.
- The large scale solar projects are sized to 20 MW, while the City Solar projects are based off available rooftop or canopy space. While the modeled wind projects were sized to the total developable potential at the site (20 to 170 MW), the total amount of large scale wind energy in the supply curve was normalized to equal the amount of energy from large scale solar to provide an equal comparison.

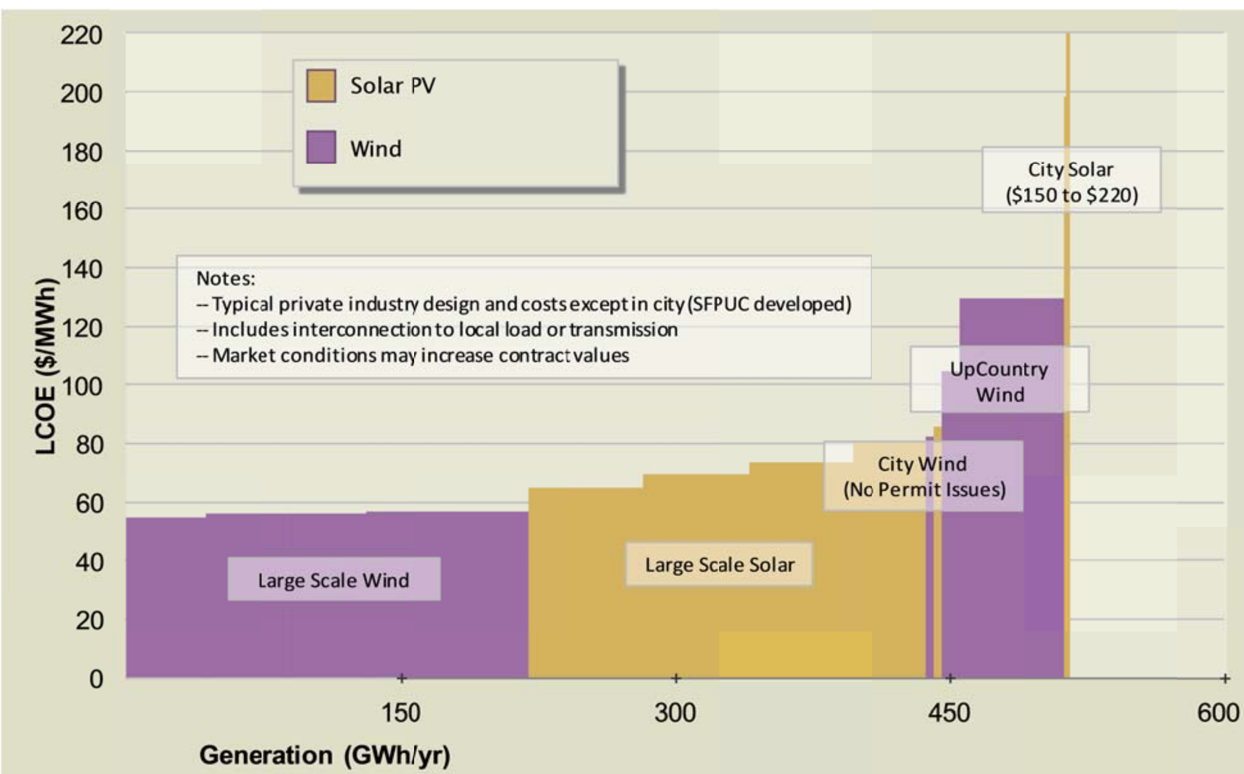

Figure 7-4 Modeled Resource Supply Curve (PPA with Transfer)

Table 7-7 Tabular Comparison of All Resources (PPA with Transfer)

NAME	TECHNOLOGY	LOCATION	SIZE (MW)	LCOE ($/MWh)
Walnut Grove	Wind	Yolo	170	54.89
Montezuma Hills	Wind	Solano	100	56.13
Newberry Springs	Wind	San Bernardino	100	56.34
Altamont	Wind (Repower)	Alameda	20	56.63
Leona Valley	Wind	Los Angeles	100	56.85
Windhub	Tracking PV	Kern	20	64.70
Imperial Valley	Tracking PV	Imperial	20	69.54
Midway	Tracking PV	Kern	20	73.50
Sunol PV	Fixed PV	SFPUC Owned, Alameda	19.2	80.48
Oceanside	Wind	San Francisco	2	82.01
Tesla PV	Fixed PV	SFPUC Owned, San Joaquin	1.6	85.40
Tesla Wind	Wind	SFPUC Owned, San Joaquin	6	104.33
Sunol Wind	Wind	SFPUC Owned, Alameda	30	129.85
Pulgas Res.	Rooftop PV	San Mateo	2.7	149.64
University Res.	Rooftop PV	San Francisco	2.9	154.39
Sutro Res.	Rooftop PV	San Francisco	2.0	168.09
Thurgood Marsh.	Rooftop PV	San Francisco	0.2	168.65
College Hill Res.	Rooftop PV	San Francisco	0.9	170.27
Stanford Heights	Rooftop PV	San Francisco	0.7	181.98
Summit Res.	Rooftop PV	San Francisco	0.7	182.15
Marina School	Rooftop PV	San Francisco	0.05	198.39
Hunters Point	Rooftop PV	San Francisco	0.005	222.67

In general, large, utility-scale facilities connected to the CAISO tend to have lower LCOEs relative to local, smaller-scale wind and solar projects located in and around San Francisco. However, other factors not quantified here such as local development and jobs, visibility, and ease of development could justify the development of more local resources.

If available for development, large wind projects are estimated to have a slight cost advantage over large solar facilities, although the projected LCOEs are very close. However, both geothermal and wind face greater development challenges relative to solar. The availability of power from new or operating geothermal facilities is limited, and wind projects face more challenging siting and permitting issues relative to new solar units. In addition, the wind output can be more variable; a closer look at the output profiles for different wind and solar projects can help the SFPUC to determine if there are time of generation advantages that would favor one of these resources over another.

If the SFPUC chooses not to take project ownership at any point during the project's life, a PPA finance structure should be considered. This is a relatively simple, well-established structure that the SFPUC has utilized in the past. This structure may increase the LCOE to the SFPUC, since the SFPUC's low cost of capital would not be used. A supply curve showing the same resources as Figure 7-4 but for a PPA structure without ownership transfer can be seen below.

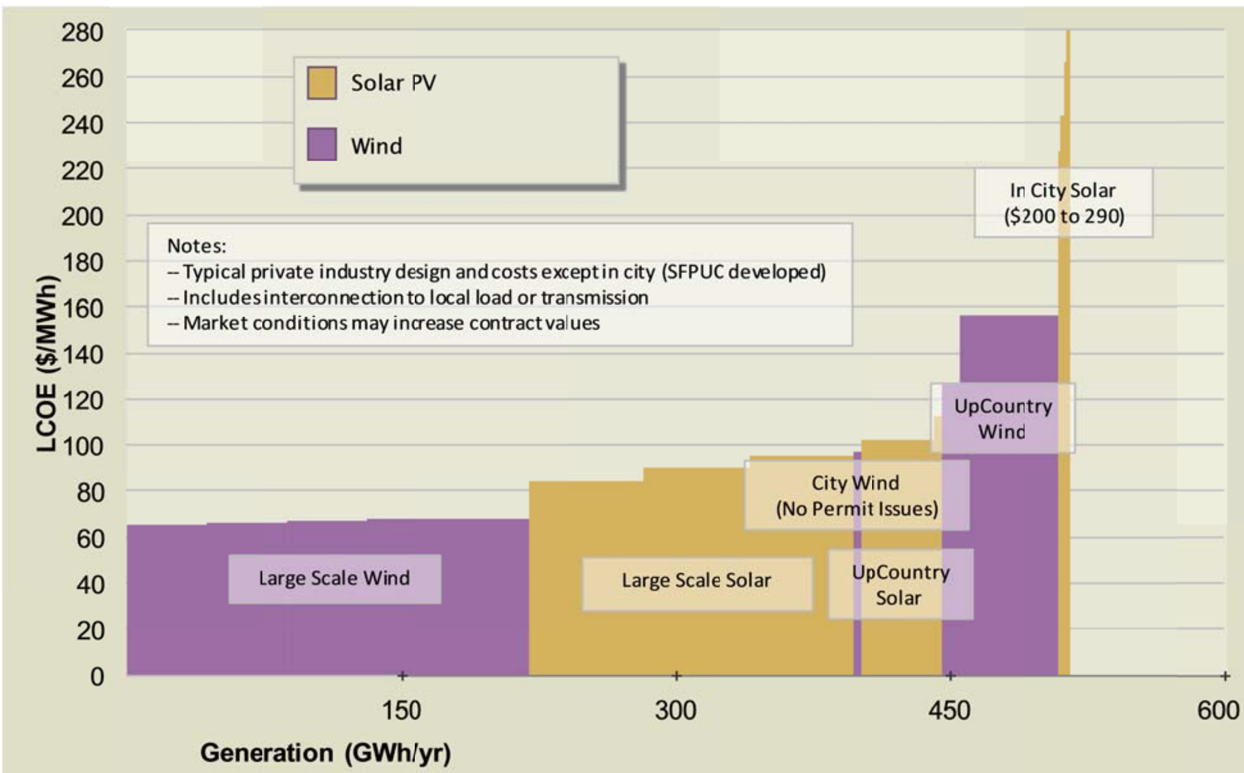

Figure 7-5 Modeled Resource Supply Curve (PPA Only)

Under this financing arrangement, the LCOEs for wind projects has increased by roughly 20 percent, while the LCOEs for solar have increase by roughly 30 percent relative to a PPA with transfer. Since solar pricing increased by a greater amount relative to wind, this moved some smaller wind projects to the left on supply curve. Solar projects have higher capital costs than wind projects, which makes their LCOEs change more significantly when the cost of capital is modified.

7.5.1 Comparison with Renewable Energy Credits

Another option available to the SFPUC to meet future renewable energy and power requirements is to purchase both on the wholesale market. Currently, both wholesale power and REC prices in Northern California are low: US DOE EIA data for 2013 shows the average market clearing wholesale price at nearly $44/MWh, while Section 7.1.3 shows that Category 3 RECs are currently trading at around $1/MWh. In the short-term, market purchases appear to be a lower cost option when compared to development of even the best resources available to the SFPUC.

If a longer-term perspective is taken into account, the economic prospects for the development of new generation improves. Black & Veatch forecasts that the 2020 wholesale Northern California power price will be roughly $54/MWh (in 2013$, equivalent to $60/MWh at 2 percent inflation). REC prices are expected to remain low unless higher goals are established for the California RPS. It is becoming increasingly likely that RPS targets will rise, which may lead to higher future REC values. Even at low REC prices, the best renewable energy resources identified in this analysis have LCOEs of $55 to 60/MWh, making them competitive with long-term purchases of green power. Locking in a price at this level in a long-term PPA would act as an effective hedge against volatile power and REC prices provided that the SFPUC projects a steady future demand for additional generation. Additional improvements in the delivered cost of power from solar PV facilities may further improve the economics of new solar plants relative to purchased power. Even with these improvements however, development of in-city facilities may remain more expensive than wholesale purchases, even over a long-term planning horizon.

7.5.2 Comparison with Developer Proposals

Data provided to Black & Veatch by the SFPUC for developer proposals show a slightly higher projected LCOE relative to the resources considered by this analysis. Without seeing detail on the assumptions used by the developers, it is hard to make a direct comparison with the projects made in this Section. Most of the developer proposals are more than a year old, which explains a portion of the difference due to changes in financial assumptions and technologies. In addition, many of the developers are using straight PPA assumptions, which will yield a higher overall LCOE price. The projections used in this report and the financial model should be utilized as a direct comparison against any future offerings made by developers to the SFPUC.